Scope: This article describes how policies and regulations affect the deployment of innovative technology by electric utilities in states with regulated and deregulated electricity markets. For the full set of articles as well as information about the contributing authors, please visit http://acee.princeton.edu/distillates.

Article 7: Supporting innovative electricity storage with federal and state policy

Introduction: Utilities and innovation

In order for energy storage to become an important component of the U.S. electricity grid, costs need to fall or rules need to change, or both. In the cases of solar and wind energy, costs have fallen with large-scale commercial deployment as the technology has progressed along a "learning curve." Commercial deployment, in turn, has been facilitated by public policies implemented at both the federal and state levels that have stimulated innovation. In the case of storage, one cannot yet know if the story will be similar.

The extra costs associated with the initial deployment of renewable energy have included the costs of research and development (R&D), the costs of pilot projects, and the costs prior to full commercialization when the first full-scale facilities incur costs that exceed the market price. These costs have been paid partly by taxpayers and partly by ratepayers (electric utility customers): governments have collected and allocated tax revenue, and utilities have collected and allocated revenue from sales of electricity, subject in the U.S. to federal and state regulations. Similar costs are arising for energy storage, again paid by ratepayers and taxpayers.

This article describes how new federal and state regulatory initiatives, rules, and policies governing the electric utility industry have affected the commercial deployment of renewable energy and could affect energy storage. It does not discuss R&D or direct government involvement in late-stage deployment (such as direct government procurement). We first review the current regulatory landscape in the U.S. at the state level, where utilities operate under two distinct kinds of regulatory regimes, with consequences for how innovation can be promoted and supported. We then explore how grid-scale renewable energy is supported via federal and state policies, to see the two parallel regulatory systems in action. We conclude with implications for the deployment of storage.

In the U.S., two parallel electric utility industries

The U.S. electric utility industry today is a "tale of two industries." In some states, a regulated industry operates under a legacy system overseen by state public utility commissions. In the other states, a "new" deregulated industry operates largely under a framework established by the federal government, with an overlay of modest state regulation that bears mostly on the distribution of electric power to customers.

This parallel industrial structure emerged only over the past 20 years, largely as the result of major federal initiatives. For most of the period since the creation of the U.S. electric power industry by Edison, Insull, and others in the late 19th century, the industry consisted of several kinds of Load Serving Entities (LSEs): Investor Owned Utilities (IOUs), federally organized entities (e.g., the Tennessee Valley Authority), utilities serving single municipalities, and Rural Electric Cooperatives. These LSEs were granted monopoly franchises by state and federal government agencies, which allowed them to operate in identified regions (service territories). Their activities were regulated by state public utility commissions (PUCs) as well as federal agencies such as the Federal Energy Regulatory Commission (FERC) and the Securities and Exchange Commission.

For the most part, irrespective of ownership, these utilities were vertically integrated. Vertical integration refers to the inclusion, in one entity, of power generation, high-voltage electric transmission, and lower-voltage power distribution to customers. The larger utilities had sufficient resources to invest in R&D and to support the deployment of advanced technology. Utilities determined the combinations of generation and transmission assets required to achieve grid reliability at least cost, and the PUCs allowed them to deploy the necessary capital in any of the segments. System reliability – the assurance that a light will come on when a customer flips a switch – became the foundational value proposition of public utilities. Today, system reliability is supplemented by new objectives, such as cybersecurity, but it retains its prominence.

The first steps toward change in the electric utility industry were taken in 1978 with the passage of the Public Utility Regulatory Policy Act (PURPA), which, for the first time, allowed non-utilities to generate power at wholesale. Restructuring of the industry began in earnest with the 1992 Energy Policy Act, which created full-scale competition in wholesale power generation, governed by federal authority. The objective of enhancing competition was to reduce electric prices, and an influential model was the deregulation of telecommunications (the dismemberment of Ma Bell). The new power-generation markets were opened so that both utility and non-utility generators could sell their power into large transmission grids. These grids are managed by Regional Transmission Organizations (RTOs) and overseen by FERC.

States were free to decline to participate in RTOs and to stay in the old system with regulated vertically integrated utilities supervised by the state's PUC. States that decided to deregulate their utility industry began the process by unbundling their power generation system from transmission and distribution, so that power was generated on a competitive basis, transmitted at high voltage over the interstate transmission system by FERC-regulated entities, and then distributed to customers via state-regulated distribution utilities. In such a market each segment of the industry acts independently. It seeks new investment opportunities and the maximization of its returns on these investments without regard for other industry segments.

Today, roughly half of the states participate in RTOs, and there is little further momentum toward deregulation. The deregulated states form a swath from New England and New York to the Mid-Atlantic States (New Jersey, Delaware, Maryland, Pennsylvania, and Ohio) and also include Texas and California, while the southeast extending into Florida as well as several states in the Midwest continue to have regulated, vertically integrated utilities. As seen in Figure 7.1, the U.S. has three single-state RTOs (also called ISOs) – New York, Texas, and California – and four multi-state RTOs.

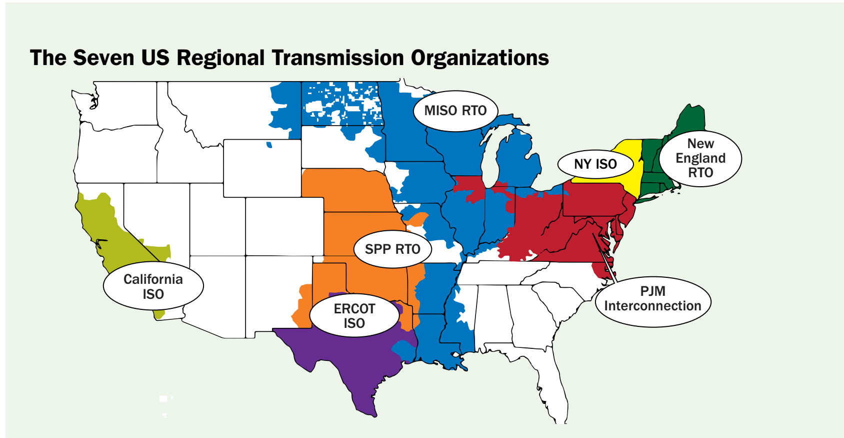

Figure 7.1 Colored regions of this map show states that have undergone partial deregulation of electric utilities, opening the generation of electricity to competition and assigning transmission to regional organizations.
Source: http://www.ferc.gov/industries/electric/indus-act/rto/rto-map.asp

Not surprisingly, investment in technology innovation in areas like electricity storage is encouraged differently in states where utilities are regulated by PUCs and states that participate in RTOs. In a fully regulated state, the traditional vertically integrated utility is responsible for all aspects of the electricity value chain and plans its investments under integrated resource planning processes overseen by state regulators. The PUC decides which of a utility's expenditures can be recovered from its customers. If a PUC judges that an innovative technology has long-term value for the state's customers, it can allow the costs of investments in R&D, demonstration, and deployment to be recovered across the value chain that includes generation, transmission, and distribution.

In states that are part of the new, partially deregulated system, power generators and owners of interstate transmission and distribution utilities can coordinate in only limited areas and in effect make investments independently. FERC, which sets the rules in these states, fosters innovation and investment by opening access to the grid and creating new performance-based markets for grid services such as energy storage. However, in this case there is no guarantee that these new markets will be sufficiently remunerative to lead to the intended investments in innovative technologies.

For the purposes of understanding current innovation processes, what matters is that the two-industry structure will remain for some substantial period of time. The reality today is that the northeast of the U.S., Texas, parts of the Midwest, and California have effectively abolished vertically integrated utilities and have created, instead, independently organized generation, transmission, and distribution segments.

The jury is still out regarding whether utility deregulation has actually achieved lower costs. Meanwhile, a new wave of regulatory reform is being discussed that would foster distributed generation and related technologies, including those required for the "smart" grid. Whatever new structure emerges will have its own consequences for the commercialization of the innovations required to manage the transitions that lie ahead in this century.

Policies for the promotion of grid-scale renewable energy

An increasingly important factor in determining the trajectory for innovation in the electric utility industry is the ascendency of renewable energy. Understanding the dynamics of the interactions between electric utility policies and renewable energy investments can shed light on the future for investments in storage. We start with the passage of the 2005 Energy Policy Act (EPAct) and the 2007 Energy Independence and Security Act (EISA). Both acts received the support of members of the Congress wishing to address climate change and wishing to encourage alternative energy sources. This legislation came in the aftermath of a dramatic increase in natural gas prices in 2005 and the collapse of both Enron and the merchant natural gas power industry. The 2005 EPAct and 2007 EISA provided for federal tax credits in the form of investment tax credits (ITCs) for solar energy and production tax credits (PTCs) for wind and all other types of renewables. Both ITCs and PTCs are available to the owners of renewable energy projects irrespective of whether such projects supply power to regulated utilities or LSEs operating in competitive power markets.

Although ITCs and PTCs have played critical roles in the commercialization of renewable energy, both have shortcomings. When a solar facility is placed into commercial service it receives an ITC that is based on the facility's capacity to produce power. After an initial period during which the ITC can be "recaptured" if the solar facility does not operate, there are no requirements that the project run for any particular period or achieve any specified level of performance.

As for the PTC, although its value to a wind project depends on actual generation for a substantial number of years, its value does not depend on the time of day when the power is produced or its value to the grid. As a result, with the PTC taken into account, wind can sometimes supply power to the grid less expensively than any other sources, even "baseload" sources designed to operate at constant output (coal and nuclear plants). In situations where wind power is abundant and demand is low (e.g., in the middle of the night), low-cost wind is creating a novel problem: the least-cost mix of power sources that meets the demand is achieved only if the grid operator accepts less baseload power than the system was designed for. Providers of baseload power then incur substantial costs for not operating at constant output.

In parallel with ITCs and PTCs at the federal level, many states have developed their own policies to encourage renewable energy. These have taken the form of Renewable Portfolio Standards, which require all utilities operating in a state to provide a minimum fraction of their power from "certified" renewable energy facilities and by specific dates. These facilities are eligible to receive state Renewable Energy Credits that can be monetized in-state and, in some cases, in broader regional markets. Exactly which kinds of facilities are certified varies from state to state, but most renewable energy technologies are certified.

Renewable Energy Credits, like Production Tax Credits, are linked to actual generation but are not valued by time of day or other metrics. Neither recognizes the value of grid impacts arising from intermittency, the high cost of power at peak times, or other costs arising from the details of the displacement of conventional generation. The market inefficiencies created by these federal and state policies to promote renewables could be addressed by introducing market-based incentives, with the result, for example, of making it more attractive to store wind produced at low-value times (a windy night), for sale into the grid at high-value times (a calm day). Another area of constructive change would bring about coordination between federal tax policy, RTO rules, and state renewable energy programs. Policies to promote storage, which we consider next, evidently interact with current and prospective policies to promote renewables.

Implications for storage

The deployment of solar and wind energy has grown rapidly, thanks in part to broad-based political support from major corporations, environmental advocacy groups, and governments. By contrast, energy storage has not yet been able to garner the support necessary to propel sustained growth and thus remains at an earlier stage in the commercialization process. The limited advocacy for new policy constructs to support the introduction of energy storage into U.S. electric grids has come largely from private companies seeking to develop and deploy energy storage technologies commercially as a new business and from renewable energy advocates who see storage as key to accelerated deployment. Nonetheless, significant initiatives have emerged recently at the federal level and in California to promote energy storage and other unconventional grid-management technologies.

To understand policy options, consider the requirement of providing reliability on the grid. Under both unregulated markets and traditional markets featuring state regulation, the National Electric Reliability Corporation (NERC), operating under FERC oversight and through its regional coordinating councils, determines minimum grid reliability standards as well as other metrics that address grid safety and security. In both kinds of markets today, electric utilities are able to support grid reliability using a portfolio of conventional generation and transmission technologies. Only rarely have utilities used energy storage to satisfy NERC's regulatory requirements. But as new energy storage options emerge, both regulatory systems are challenged to respond, and they are likely to respond differently and in different timeframes.

In a regulated state the initiative for introducing energy storage lies with its PUC. The PUC determines the portfolio of generation assets that the utilities under its jurisdiction must hold, including the assets the utility is required to hold in reserve. The utility then invests in the appropriate resources and operates its portfolio of generating units to maintain this level of reserve. The PUC allows each utility to recover from its customers all capital and operating costs associated with reserve power. The utilities, in turn, have no need to separate the cost of providing operating reserve from the cost of generating energy. The PUC regularly evaluates the integrated resource plans formulated by its utilities to ensure that system reliability is being achieved at the lowest cost. The PUC, for instance, can decide to mandate storage investments, on the grounds that early deployment of storage will buy down its cost, to the long-term benefit to its customers.

The situation is more complicated in states where there is an RTO. NERC's reliability rules are then implemented not by a single entity such as a vertically integrated utility but, potentially, by transmission owners, LSEs, and even individual generators. The challenge is to assure that reliability standards are implemented in a way that is consistent with established governance and market design. An LSE seeking to meet its reserve requirements will commit to energy storage only if it is the least-cost way of doing so. Absent special circumstances, the LSE cannot recover from its customers any extra costs of meeting its reliability requirements resulting from using a storage option rather than a conventional resource such as a natural gas turbine.

New FERC regulations

Cost-competitiveness within an RTO depends on the rules that FERC sets. In the past several years, notably in its Order 755 (October 2011) and Order 784 (July 2013), FERC has focused on insuring that all innovative technologies capable of providing reliability-related services to the grid compete on a level playing field, when it comes to market compensation for the services they provide. For example, FERC recognizes that many storage systems can add or remove load from the grid more quickly and with greater accuracy than conventional generators. The result is better "ancillary services," such as tighter control of the frequency of alternating current (AC) so that it stays very close to 60 cycles per second. FERC now requires its RTOs to send out two different signals to accomplish frequency regulation, one requiring a faster response and one requiring a slower response, and to pay more for the faster response. (Previously there had been only one signal.) Only a few generators on the grid can respond to the faster signal, but many storage systems have the potential to do so. In these ways FERC is improving the competitiveness of fast-response storage for ancillary services. PJM (the largest of the RTOs) is implementing the new FERC orders particularly rapidly.

New California state regulations

The California ISO (as this RTO is called, see Figure 7.1) is proceeding in a unique fashion today, because it is being driven not only by FERC orders but also by state regulations governing the California Public Utility Commission (CPUC).

California has long been committed to including a significant share of renewable energy in its electricity generation mix (33 percent of total power generation by 2020). Toward this end, the state of California has been developing its own regulations to accommodate intermittent generating resources while maintaining grid reliability. Specifically, California now has state legislation, AB2514, enacted in 2011, which directs the CPUC to promulgate rules that support the commercial deployment of energy storage across the entire electricity value chain.

To implement AB2514, in October 2013, after a three-year deliberative process featuring stakeholder engagement, the CPUC announced the first mandatory energy-storage procurement targets in the nation. The targets apply to California's three major investor-owned utilities: Southern California Edison, Pacific Gas & Electric, and San Diego Gas & Electric. Collectively, they are required to procure 1,325 MWs of energy storage capacity by 2020, with an installation deadline of the end of 2024.

To drive industry toward advanced technologies, there are CPUC rules limiting the use of conventional energy storage technologies, such as pumped storage of hydropower, to meet the targets. Additional CPUC rules seek to foster a storage industry that is independent of the state's utilities: utilities are not allowed to own a majority of the storage resources, and utility-owned storage is preferentially treated when it has not been developed by the utilities themselves but rather has been developed by others and sold to the utility on a turnkey basis under a purchase agreement. Overall, the CPUC is seeking to create significant new market demand and new supply for a broad range of advanced energy storage technologies.

The CPUC recognizes the issue of storage cost by requiring energy storage targets and procurements to be "viable and cost-effective," based upon a predetermined methodology developed for each utility. To provide flexibility, the CPUC allows a utility to meet its targets by a wide range of combinations of transmission projects and distribution projects. Thus, substantial investment in innovative multi-hour storage is not assured. To the extent that the primary reason for policies supportive of storage is to facilitate a large role for renewable energy, if only modest investments in multi-hour storage are forthcoming, one can imagine that procurement rules would be revisited. As it is, targets can be revised on an ongoing basis, and a utility is allowed to defer up to 80 percent of its targeted procurement to the next solicitation period.

The integration of FERC rules and CPUC rules to assure coherence and self-consistency is currently a work in progress.