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Electric Power Markets and State Policy:

Changing Dynamics amid Federal Policy Uncertainty

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KEY POINTS

- The electric power sector is facing a set of trends related to electricity demand as well as technology- and policy- driven shifts toward low-carbon generation that are occurring regardless of federal policy.
- These broad trends have led to market dynamics—such as falling wholesale electricity prices and increasing shares of natural gas and renewable resources—that pose challenges to current electricity markets, including incumbent coal and nuclear power plants.
- States, utilities, and regulatory bodies have developed a range of approaches to address these challenges and also are continuing to pursue their own priorities regarding climate and clean energy technology policy.
- Better aligning market incentives and state policy priorities can improve efficiency in US electricity markets and help achieve policy goals cost-effectively.

Introduction

In the early days of the Trump administration, we're seeing a major shift in federal energy policy—moving away from efforts to address the risks of climate change. At the same time, the electricity industry is undergoing rapid technological transformation, and states are adopting policies that may accelerate or otherwise affect these changes. These developments raise important questions about the future of US energy policy at both the federal and state levels and, in particular, how the electric power sector will be affected.

The Policy Context

Despite increased policy uncertainty at the federal level, the power sector is undeniably undergoing a series of changes already, driven to a significant degree by market forces and state-level policy. The US electric power sector is therefore confronting at least three major dynamics related to demand, technology, and policy that will remain important—regardless of changing White House policy.

- Flat electricity demand, driven by slower than expected economic growth in the wake of the Great Recession and the decoupling of electricity use and economic growth in the recovery through increasing energy efficiency
- Technology-driven shifts, including the shale gas revolution; falling costs of wind and solar electricity production; the incorporation of information technology and analysis into energy management; and the falling costs of energy storage
- Policy-driven shifts, toward low-carbon electricity, including environ-

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mental regulation of greenhouse gases (GHGs) and other impacts associated with coal, as well as financial support for renewables and energy efficiency

These major dynamics have led to a range of more specific market issues that utilities, regulators, and lawmakers are already facing:

- Electricity capacity growth, despite flat demand (Figures 1–3)
- Falling wholesale power prices that challenge incumbent baseload sources such as nuclear and coal plants (Figure 4)
- The need to balance electricity load given an increasing share of generation coming from intermittent renewable sources (Figures 5–6)
- The need to resolve the questions of whom, how, and how much to pay for services such as capacity, ramping, and distributed generation

Despite the Trump administration's push to roll back the Clean Power Plan, we can expect many states to continue their own efforts to mitigate GHG emissions and increase clean energy generation. These priorities need to be reconciled with the broader market issues mentioned above.

Over the next few years, these efforts will play out in three key areas: electricity market policy, climate policy, and clean energy technology policy. The remainder of this brief illustrates how these policies are unfolding at the state and regional levels.

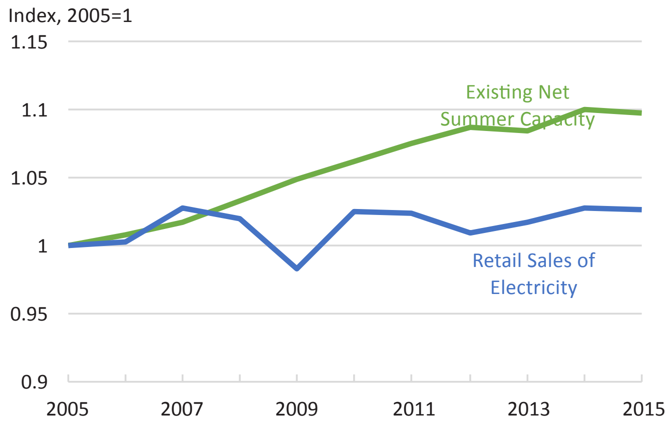
Electricity Policy

Falling wholesale electricity prices are a symptom of capacity growth in resources with low and zero marginal cost—specifically, natural gas and renewables. In the case of nuclear power, some states and utilities are already addressing the problem that low wholesale prices pose to existing plants.

In California, this has led to PG&E's proposed closure of its last operating nuclear plant, Diablo Canyon. PG&E has said it plans to replace the plant's capacity with a combination of energy efficiency, renewables, energy storage, and demand-response initiatives. In contrast, New York and Illinois have both approved programs to subsidize nuclear plants at risk of closure.

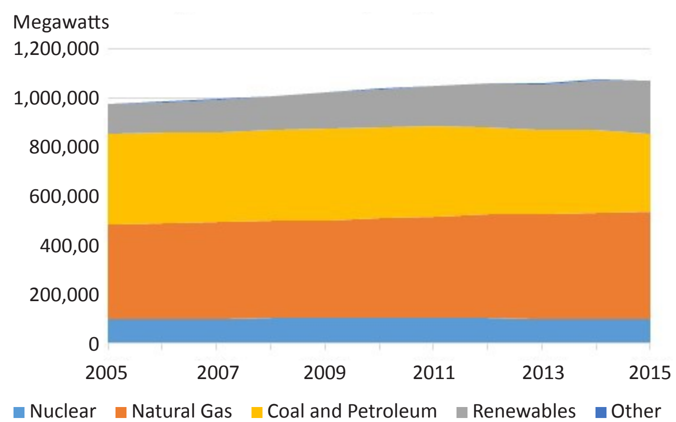
This state-based approach is already leading to varying outcomes, reflecting differences in how states and utilities are assessing whether—and how much—to pay for nuclear capacity. Although nuclear has no carbon emissions, it cannot ramp quickly and existing plants may have significant incremental fixed costs as plants age.

Figure 1. Existing Net Summer Capacity and Retail Sales of Electricity, 2005–2015



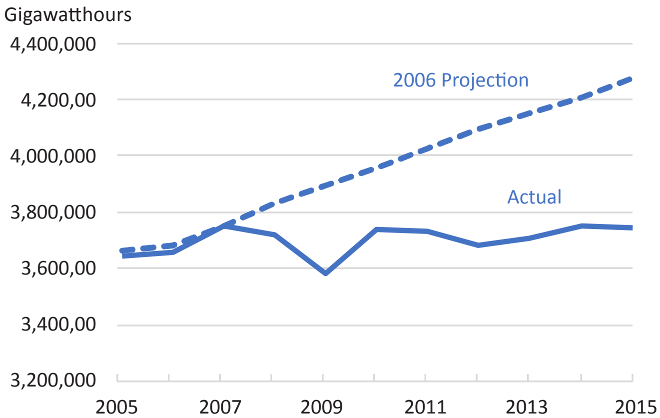
Source: US Energy Information Administration (EIA) Electric

Figure 2. Existing Net Summer Capacity, 2005–2015



Source: EIA Electric Power Annual 2015.

Figure 3. Retail Sales of Electricity, Actual vs. Projected, 2005–2015



Source: EIA Electric Power Annual 2015; EIA Annual Energy Outlook 2006.

This variation in state and utility approaches will likely continue—and will be highly debated—in the absence of a blanket federal policy on nuclear sources. But, one might ask, would a uniform federal approach be better or is the tailored response that differs among the states a better solution for each situation? The answer depends in part on the degree to which policy goals are local versus national or international in scope.

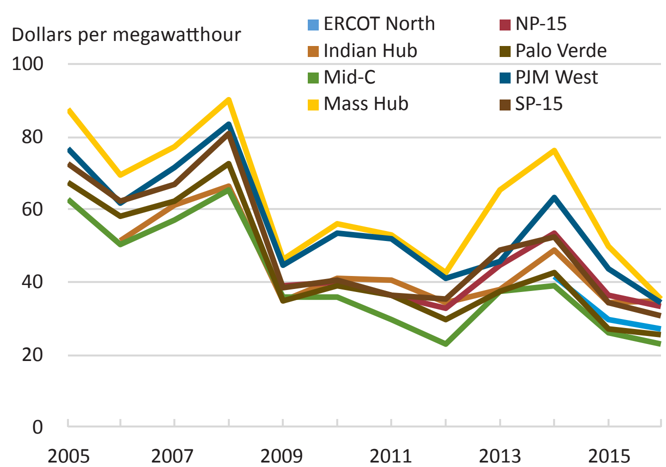
A separate issue is the question of what to pay for distributed energy resources such as solar. Although net metering is still the norm, states with a high proliferation of distributed solar are rethinking their net metering policies. The economic argument is that the private savings from installing distributed energy resources are greater than the overall savings that they provide to the grid. This disparity can lead to inefficient levels of distributed energy resources—which could cause utilities to raise electricity prices, potentially resulting in a feedback loop of rising electricity prices and increasing installations of such resources—leading to the so-called utility death spiral.

A well-designed value of solar would price the net benefits that distributed solar generation provides to the grid. It would be location- and time-specific, and would account not only for the value of peak solar generation, but also for the cost of fast-ramping back-up capacity that must be available to fill in when the sun isn't shining.

In addition, capacity market reform is becoming a salient topic for grid operators in regions that encourage and subsidize zero-carbon generation. ISO New England and PJM (the regional transmission organization serving thirteen eastern states and Washington, DC) are good examples, where two-part capacity auctions have been proposed. The primary auction would operate as it does now, using the minimum offer price rule that currently applies only to natural gas plants, plus a provision that prevents other state-subsidized resources from submitting price bids that are lower than their costs. The second part would coordinate the exit and entry of resources and could prove an efficient way to better align market operations with states' decisions to subsidize certain resources.

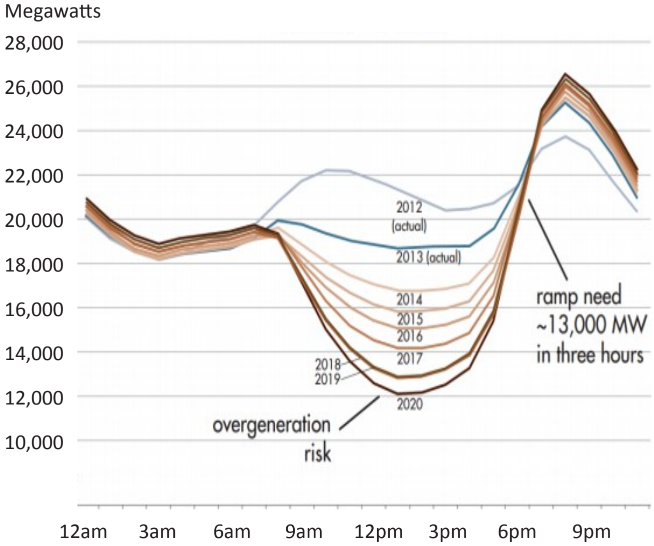
The issues discussed so far pertain to modernizing grid operations and electricity policy as the costs of natural gas and renewables fall. They are the symptoms of both market and policy dynamics, and they will remain priorities regardless of federal climate policy.

Figure 4. Average Annual Wholesale Electricity Prices for Eight Major Hubs, 2005–2016



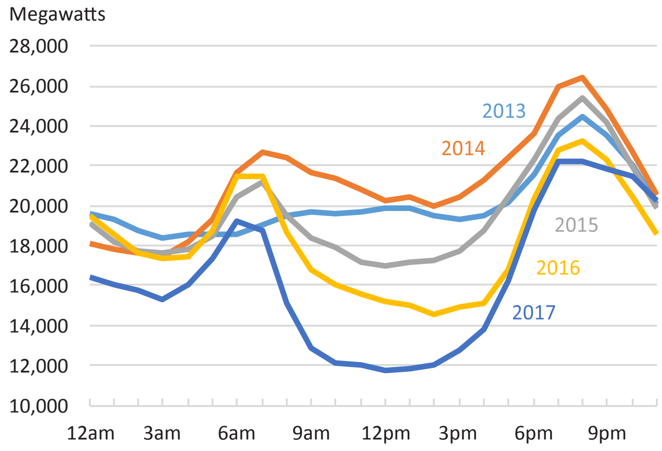
Source: EIA, based on data collected by the Intercontinental Exchange (ICE).

Figure 5. California Independent System Operator (CAISO) Projected Net Load as of 2013



Source: California Independent System Operator (CAISO) 2013.
Note: Figure is a daily snapshot for March 31. CAISO manages the majority of California's electricity flow. Net load represents the total electricity demand minus wind and solar generation. California is a large electricity market that has a higher than average penetration of intermittent renewable generation.

Figure 6. CAISO Actual Net Load as of 2013



Source: CAISO.
Note: Figure is a daily snapshot for March 31. CAISO manages the majority of California's electricity flow. Net load represents the total electricity demand minus wind and solar generation. California is a large electricity market that has a higher than average penetration of intermittent renewable generation.

Climate Policy

The prospects for state climate policies in the absence of the Clean Power Plan are more of a mixed bag. "Climate policies" refers to those that focus directly on reducing GHG emissions. For better or for worse, state-based climate policy has been the rule rather than the exception in the United States.

The United States has a rich history of state leadership in designing environmental policies and demonstrating their feasibility. Opportunities for learning abound when it comes to market-based climate policy, with two subnational cap-and-trade programs already implemented (California's, and the Regional Greenhouse Gas Initiative, or RGGI, in the Northeast and Mid-Atlantic). California's cap-and-trade program is currently heading into a restructuring effort, the outcome of which is still uncertain. What is already determined, however, is that California's emissions cap will continue increasing in stringency.

California's ambitious goal for 2030—of reducing emissions 40 percent below 1990 levels—is likely to put electrification pressure on other sectors, particularly on water heating, space heating, and vehicles, presumably reversing the trend toward falling electricity consumption.

In the RGGI region, low allowance prices mean that the program has a fairly small impact on the relative order of resource use in wholesale markets. It is having its greatest impact through the funding of energy efficiency spending via auction revenues, and by signaling it provides that encourages long-term investment in resources with low- or zero-carbon capacity.

Electric utilities make resource portfolio decisions that have impacts extending far longer than an election cycle. Managing regulatory risks requires consideration of future climate policies that may be implemented during the lifetime of resource investments.

Using carbon prices in integrated resource plans (IRPs) is an efficient way to begin aligning business decisions with the incentives that future climate policies may create. Since many IRPs projected carbon costs using scenarios considering compliance with the Clean Power Plan, its rollback may increase uncertainty in scenario modeling.

RFF Visiting Fellow Joe Kruger has pointed out in a new report that state regulators can help address this uncertainty by providing guidance to utilities on how to use carbon pricing in IRPs. Minnesota, for example, requires the use of an externality value for carbon in IRPs. A state judge has recommended that the Min-nesota Public Utilities Commission adopt the federal social cost of carbon as the externality value. RFF is in the process of launching a research initiative to respond to recent recommendations by the National Academy of Sciences for updating the social cost of carbon to ensure it reflects the best available scientif-ic evidence.

Clean Energy Technology Policy

The third and final key area of policy activity—policies aimed at mandating or subsidizing generation from renewables—is far more widespread than emissions-focused climate policy. Clean energy technology policies may not mitigate GHG emissions as efficiently as market-based climate policies, but they do apparently hold the advantage of better political feasibility.

In fact, mitigating GHG emissions may not always be their primary motivation. Boosting renewable energy is often motivated by local economic interests and other concerns, including job creation and pollution. To date, twenty-nine states and the District of Columbia have adopted renewable or alternative energy portfolio standards, and nine others have voluntary renewable goals.

The success of state renewable portfolio standards relies to some degree on federal production and investment tax credits, a fact that has been brought up in the context of tax reform. It seems unlikely that federal tax reform negotiations will pose a serious threat to those tax credits, at least through their current expiration dates a few years from now. As we point out above, policymakers need to work toward better integration of state clean energy technology policies with electricity market operations to help those markets operate efficiently while also meeting policy goals cost-effectively.

We are also seeing a range of electricity consumers exerting their own resource portfolio preferences when they do not match what utilities are supplying. Microsoft reached a deal with Puget Sound Energy in April to purchase its energy directly from the wholesale market—a deal meant to help Microsoft meet its internal renewable portfolio goals.

A similar story is also playing out at a smaller scale through a system known as Community Choice Aggregation, in which residential customers pool together to choose their energy portfolio. As both major corporations and smaller-scale residential communities pursue their own preferences for renewables, the question of what and how much to pay for utility services such as reliability and distribution becomes even more important. These trends also put pressure on the regulated electricity markets, where it is more difficult for consumers to exert their own preferences.

Conclusion

The shift toward low- and zero-carbon electricity resources and flat total electricity demand are driven to a significant degree by market forces and state-level policy—and these trends are not going to disappear in the next few years. The changing characteristics of both supply and demand necessitate some rethinking of whom, how, and how much to pay for services such as backup capacity, storage, and fast ramping that have not traditionally been worked into power markets. Considering these issues will help market incentives better align with a wide range of policy priorities that states can be expected to continue to pursue regardless of federal policy.