Technical and Institutional Barriers to the Expansion of Wind and Solar Energy

Near-term measures to foster development

Prepared for Peter Fiekowsky, Citizen's Climate Lobby

June 19, 2015

AUTHORS

Patrick Luckow
Bob Fagan
Spencer Fields
Melissa Whited

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

CONTENTS

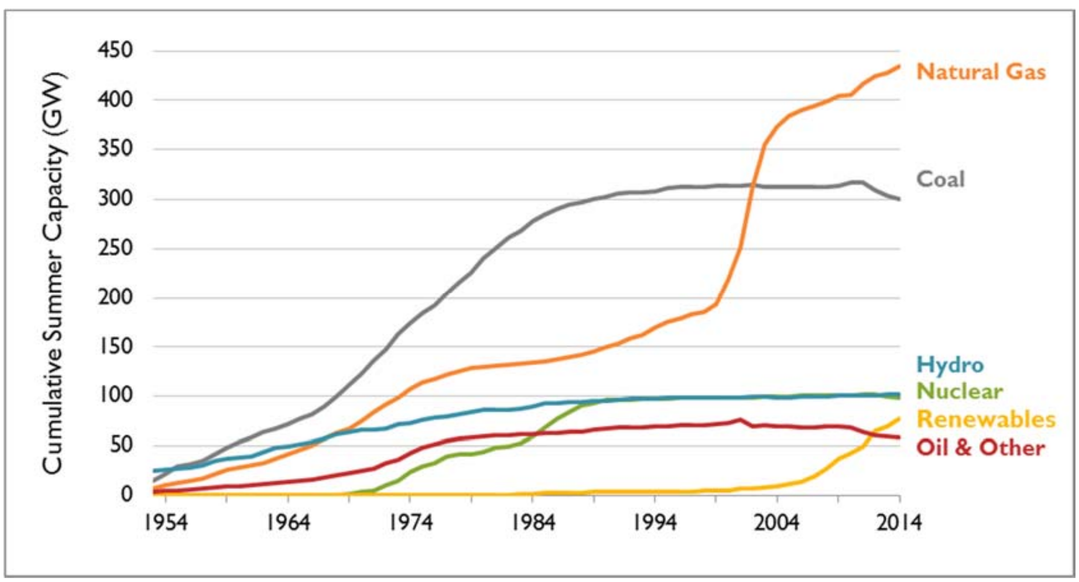
1. INTRODUCTION

The expansion of renewable energy technologies, particularly wind and solar energy, continues to face barriers despite dramatic cost declines in the last decade. Some of these barriers are legitimate technical issues, but many are based on “virtual” inefficiencies—limitations associated with structures, communications, and procedures that have adapted in a localized, fossil fuel-centric power market.

New power plant additions in the United States have been historically dominated by fossil fuels: by natural gas more recently, and by coal before that (see Figure 1). In the last several years, renewables have been gaining steam. As of March 2015, coal capacity fell below 300 GW for the first time since 1988. The U.S. Energy Information Administration’s (EIA) most recent Annual Energy Outlook foresees a continuation of this trend for the next several years, with coal capacity declining to 259 GW in 2017 under the pressure of low gas prices and deadlines to meet compliance with U.S. Environmental Protection Agency (EPA) regulations, such as the Mercury and Air Toxics Standards (MATS). New capacity additions have been a mix of renewables and natural gas. There is eleven times as much utility-scale solar on the grid today than in 2010, and five times as much rooftop solar. Wind energy has continued to grow as well, and already represents the lowest-cost new energy resource for some utilities.

This report identifies several of the key institutional, regulatory, and market barriers that need to be overcome in order for renewables to continue their rapid rate of expansion.

Figure 1: Cumulative summer electric capacity in the United States, 2001-2014



Source: EIA Form 860 and Electric Power Monthly

This report identifies:

- Perceived, but not actually limiting, barriers
- Technical hurdles, including balancing area cooperation and transmission requirements
- Siting challenges
- Renewable Portfolio Standard (RPS) policy limitations and inadequacies
- Rate design that discourages new renewable installations

These are not so much barriers as hindrances in the near term. For the next five years, the limitations to new wind and solar capacity are largely "virtual" in nature. For example, regional system operators have not historically worked well with their neighbors in the current localized structure. However, regional transmission organizations (RTO) have begun to implement coordinated scheduling to facilitate transactions across RTO lines. Equally small but significant changes to the other areas identified in this report will foster the development of renewable energy, and let utilities and ratepayers take full advantage of recent cost declines. In the longer term, further development of renewables will likely require more physical improvements—from substantial transmission system additions and reinforcements to improved ramping abilities of gas generators. Having these physical changes in place in the 2020-2025 timeframe will require proper planning and foresight over the next several years.

2. Some Supposed "Barriers" to Wind and Solar Will Not Be an Issue for Many Years

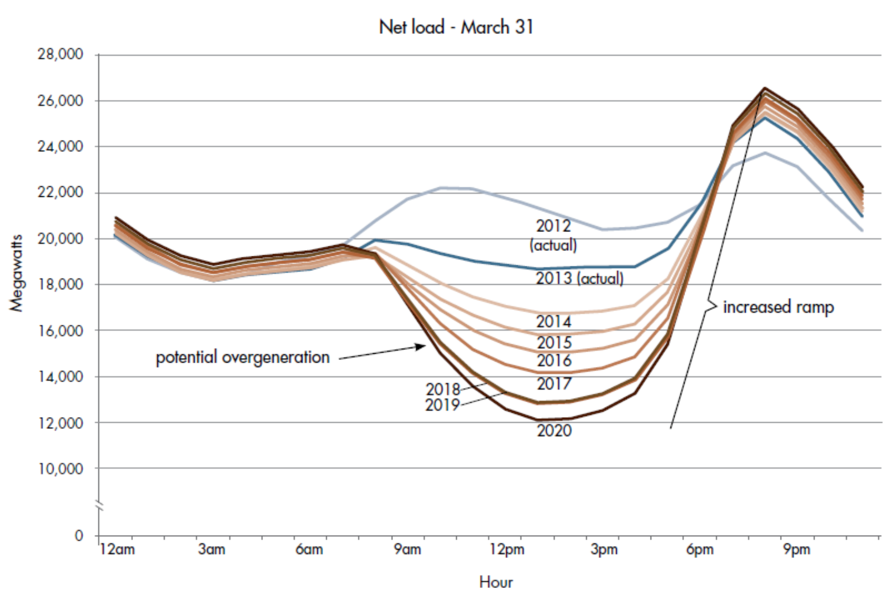
The critique most often used as an argument against the expansion of wind and solar energy is that it will cause the grid to become unstable. However, the power system is a regional or multi-regional system composed in part of many different forms of supply-side resources (e.g., conventional fossil fuels, hydroelectric, nuclear, solar, wind). Each and every one of these types of resource is sometimes unavailable to produce energy, for either planned or unplanned reasons. It is not just varying-output renewable resources that are sometimes unavailable. One often overlooked benefit of utility-scale wind and solar is that most failures only bring down a small fraction of the overall plant—one wind turbine, or one array of panels—whereas a failure at a steam turbine risks a much larger outage.

When any of these resource types are not operating, the remaining available resources provide the collective energy and ancillary service requirements needed and system response times remain the same. System designers and operators know this. And while wind and solar energy are generally not dispatchable by system operators in the same sense that existing fossil fueled power plants are,[1] this near-term challenge is quite tractable. The communication, coordination, and analytical capabilities of those who run the system and their inherent understanding of how load and resource output patterns can and do vary (along with the presence of sensibly calculated operating reserve margins) will make balancing the needs of a more diverse range of resources relatively straightforward, at least for the next several years. In particular, concerns over the ramping ability of power plants to support solar energy and over the vulnerability of the grid during extreme events are overblown. For the longer term, there is no shortage of means and technologies to continue the same successful balancing act.

2.1. Ramping Concerns May Be Overstated in the Near Term

Increasing levels of onshore wind and solar photovoltaics (PV) can create substantial ramping needs in the shoulder hours (the hours that precede and follow peak usage) when PV or wind output can change relatively rapidly. During periods of relatively low load, conventional power plants may generate very little electricity during the day when solar generation is at its maximum, and need to ramp up quickly as the sun sets. This ramping pattern is represented in the California ISO's "duck chart," so called because the shape of the load curves resembles a duck (the chart is reproduced in Figure 2 below).

Figure 2: California "duck curve"



Source: California ISO. December 2013. "Demand Response and Energy Efficiency Roadmap: Maximizing Preferred Resources." Available at: http://www.caiso.com/Documents/DR-EERoadmap.pdf.

[1] The curtailment of wind and solar resources could be thought of as dispatch – turning a plant down at the control of the system operator. Generally, the economics support utilization of wind and solar resources if the "fuel" is available but it is technically feasible that some level of dispatchability can be used with some of these resources, at times.

Older coal units are particularly poorly suited to the task of ramping up quickly, but as coal retires and is replaced by more efficient and flexible gas units, the system will be able to adequately respond to the need. Three factors increase the ability to respond to “duck curve” issues:

- System size: Large systems can take advantage of geographically diverse resources and loads, as well as a higher absolute number of generators, to balance ramps in a straightforward manner.
- Demand response and smart grid: New tools to actively reduce load in the early-evening peak hours, as solar generation is falling, can reduce the level of fossil ramping required, particularly by being available to shave (i.e., reduce) what will otherwise be the highest net peak load hours of the day. The most extreme ramping events happen on only a few days per year, and the ability of system operators to call on customers to reduce loads, or shift consumption to another time of day, can reduce the need to purchase new gas capacity.
- Change in resource adequacy products: Energy and capacity markets are already changing to value the ability of plants to ramp.[2] Old, inflexible units put a cost on the system due to their poor performance in this regard. New markets will properly incentivize more flexible units.

2.2. System Stability Concerns Can Be Addressed with Today’s Technology

Some have expressed concern that increasing levels of renewable energy make the grid more vulnerable to outages and extreme events. The large quantity of physically spinning fossil generation assets are able to automatically respond to disturbances in a way that wind and solar resources are not—but technology developers have been actively working on this issue for a number of years. A study released in the spring of 2015 by General Electric and the National Renewable Energy Laboratory (NREL) found that even with an 80-90 percent decrease in the amount of operational coal plants, the grid could respond to faults in a timely and reliable manner, with only modest transmission reinforcements.[3]

3. Transmission and Other Technical Barriers Still Need to Be Addressed

There are a number of legitimate technical barriers to the substantial expansion of wind and solar energy—several have straightforward solutions, and others need further research to be overcome.

---

[2] For example, the California ISO wholesale market pricing algorithms include “flexibility” constraints that sometimes—when needed—result in additional revenue for resources that can provide extra ramp capability, even though there is not yet a formal “load following” ancillary service market product. See, for example, http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf at page 96.

[3] Miller, N., M. Shao, S. Pajic, and R. D’Aquila. 2015. “Western Wind and Solar Integration Study Phase 3 – Frequency Response and Transient Stability.” Available at: http://www.nrel.gov/docs/fy15osti/62906-ES.pdf.

3.1. Reduce Limitations at Regional Transmission Organization and Balancing Authority Seams

A balancing authority is an entity responsible for balancing supply and demand in a given geographic area. This entity is not only responsible for developing transmission plans and overseeing resource adequacy, but critically is the system operator with NERC (North American Electric Reliability Corporation) authority and responsibility for committing[4] and dispatching power plants, maintaining interchanges with other balancing authorities, and supporting frequency in real time.[5] Regional Transmission Operators have these same responsibilities, but also provide transmission access to independent generators and conduct markets to cost-effectively dispatch power plants from a number of owners. Their size and coordination helps to integrate wind and solar resources. The major RTOs in North America are shown in Figure 3. NREL's 2011 Eastern Wind Integration and Transmission Study (EWITS) found that cooperation and consolidation among balancing areas, combined with transmission enhancements, were "the most effective measures for managing wind generation."[6] Smaller balancing authorities were challenged by the high wind levels (20-30 percent) in the EWITS study, and required significant levels of transmission additions.

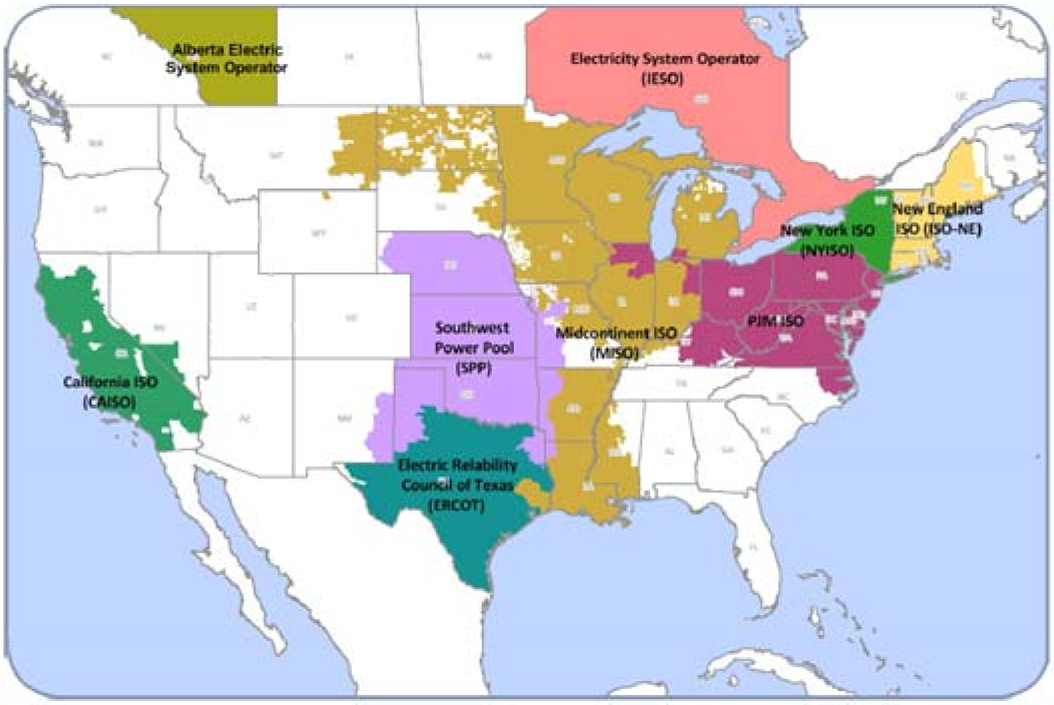
---

[4] "Committing" a power plant is the decision to turn on or turn off a power plant while abiding by temporal restrictions (start times, requirements to "cool down" after it is turned off before being switched back on, etc.). Balancing authorities used a range of simple to sophisticated mechanisms to determine when and over what timeframes to do this. Once committed, a gas or coal plant is restricted to operating above its minimum operating level, typically 40-50 percent of rated capacity for older plants.

[5] North American Electric Reliability Corporation. 2009. "Glossary of Terms Used in Reliability Standards." Available at: http://www.eia.gov/electricity/data/eia411/nerc_glossary_2009.pdf.

[6] NREL. 2011. "Eastern Wind Integration and Transmission Study." NREL/SR-5500-47078. Available at: http://www.nrel.gov/docs/fy11osti/47078.pdf.

Figure 3: North American RTOs as of Summer 2014



Source: Federal Energy Regulation Commission created with Energy Velocity. Available at: http://www.ferc.gov/market-oversight/mkt-electric/overview/elec-ovr-rto-map.pdf.

While there is concern over the ability of existing fossil resources to provide sufficient flexibility to balance swings in wind and solar generation, for the most part the size of existing markets should be sufficient to meet this need in most areas of the country. One exception is in Hawaii, where old, inflexible oil generators cannot turn down to allow the rapid influx of solar PV on the grid, and where there is no connection to a larger regional system. In California, discussions have been ongoing related to the "duck curve" phenomenon, where resources have to rapidly respond to falling solar output in the evening, but these discussions are focused on the post-2020 time period. In the near term, transactional, not physical, improvements will be required to continue to integrate wind and solar technologies. Institutional barriers slow the process of interregional cooperation, but progress is being made across the country.

In the East

The sheer size of the PJM and MISO systems offsets most flexibility constraints posed by aging fossil fleets. In its latest renewable integration study, PJM found it could accommodate up to 30 percent variable renewable energy (**more than 100 GW**) with no major issues. These scenarios did find a need for about $8 billion in new transmission system upgrades and new lines, as well as an increase in the amount of operating reserves PJM is required to carry. While this is a modest undertaking to complete by the study target date of 2026, a more rapid expansion of wind and solar resources will require a concerted effort to complete these upgrades earlier.

Further integration between SPP and MISO, and between these regions and the TVA and southern systems, will be highly valuable to flow power from areas where the cost of wind is low to load centers in the south central regions of the country. Stacking wheeling charges at each transmission facility (called “pancaking” transmission rates) can unnecessarily make wind resources available in the SPP and MISO systems incrementally more expensive to load serving entities in the regions to their southeast; this expense could be reduced by further coordination.[7]

The regional market in New York, NYISO, is working with neighbors to the east (ISO-NE) and west (PJM) to increase real-time scheduling. In late 2014, NYISO began to implement coordinated transaction scheduling to facilitate transactions across RTO lines.[8] This will lower costs of the system as a whole, better integrating the existing regional resources. Together these three regions represent about 250 GW of generating capacity.

The vertically integrated utilities of the South, as well as TVA, could be a destination for initially 5-10 GW of wind from SPP, delivered via high voltage direct current (HVDC) lines terminating at the TVA border or in the western portions of the Southern system.[9] As TVA in particular is faced with the cost of retrofitting a number of coal plants, the ability of new transmission resources to deliver low-cost renewable energy could allow these plants to retire, reducing emissions and saving ratepayers money. In the next five years, a broader understanding of the importance of these new transmission assets is essential to finalizing siting and beginning construction.

In the West

Improved transmission scheduling is already happening elsewhere across the country, as a result of FERC Order 764, which requires intra-hourly transmission service; in some areas, this has also resulted in the formation of 15-minute energy scheduling protocols.[10] This will allow systems to more efficiently (i.e., more economically) balance intra-hour fluctuations in wind and solar generation. The California ISO (CAISO) began such transmission scheduling in 2014, and went further than the minimum requirements

[7] Pancaking refers to multiple, sequential charges for transmission access across systems. MISO and PJM eliminated pancaking between their systems, allowing for more economically-efficient scheduling of resources that generate in MISO and are used by load in PJM (and vice versa). Over the past decade plus, FERC has been advocating for, and instituting tariff reforms that reflect, the elimination of pancaked rate structures for transmission access. See, for example, http://www.naruc.org/Grants/Documents/NRRI%2015-03%20NRRI%20-%20Seams%20Primer_3.pdf.

[8] NYISO Coordinated Transaction Schedule available at: http://www.nyiso.com/public/webdocs/energy_future/issues_trends/broader/brm_documents/CTSPamphlet20141003Final.pdf.

[9] As found in the Eastern Interconnection Planning Collaborative (EIPC) study available at: http://www.eipconline.com. The suite of merchant HVDC projects proposed by Clean Line Energy Partners represents a similar level of new transmission (http://www.cleanlineenergy.com/projects).

[10] For example, California (to/from the Pacific Northwest, and the desert Southwest), New York, PJM, and New England now have at least some form of 15-minute energy scheduling capabilities across their interregional interties. MISO and PJM are working towards implementation of 15-minute scheduling between their regions by 2016.

of the FERC Order by incorporating 15-minute energy transaction scheduling as part of its new region-wide energy imbalance market (EIM).

PacifiCorp, a utility operating in six Western states, began participation in the CAISO EIM in late 2014, and will be joined by Puget Sound Energy and NV Energy in 2015 and 2016. This market will cover seven states and 44 million people, and will improve the ability of operators in all associated areas to manage renewable integration.[11] Notably, PacifiCorp is now planning on formally joining the CAISO RTO, which will expand the CAISO's day-ahead market reach and potentially allow for even greater renewable integration efficiencies by coordinating unit commitment across a broader region.[12]

A continuation of this trend of improved coordination in the Western Electricity Coordinating Council will facilitate better unit commitment decisions and further integration of renewables. This entails overcoming a "virtual"[13] barrier—some new systems are required for better integration, but by and large it simply requires getting the right people talking to each other. Institutionally, it will be important to foster cooperation among RTOs and investor-owned utilities in the West at a rapid pace to incorporate new renewable additions.

3.2. Build Merchant High Voltage Direct Current Transmission Lines

There is already substantial economic justification to build new merchant HVDC transmission lines as dedicated pathways to bring renewable energy from large utility-scale wind and solar energy installations to population centers. Most of these projects are not essential for the expansion of wind and solar in the next several years, but will be important to the next large phase of renewable energy expansion, expected to occur in the 2019-2024 timeframe.[14] In order to make sure they are online in this timeframe, siting of these lines needs to be facilitated in a fair and efficient manner.

While these lines are being financed by merchant developers, cost recovery guarantees from state and federal regulators could facilitate more rapid development, and reduce the investor risk over what can be an extended permitting and review process.

There have been numerous successful merchant transmission build-outs in the last decade. The Champlain Hudson Power Express was proposed seven years ago and the developers plan to begin construction in 2016, linking the New York Metro area to Hydro-Quebec. The Cross-Sound cable linking

---

[11] CAISO. 2015. "Energy Imbalance Market Overview." Available at: https://www.caiso.com/informed/Pages/CleanGrid/EIMOverview.aspx.

[12] Coordination of unit commitment across broader regions can reduce concerns about the need to sometimes curtail renewable energy output to assure the presence of sufficient peak-load serving capacity for any given operational day.

[13] As opposed to formal consolidation of balancing areas, such as occurred with the evolution of now-single control areas ERCOT, SPP, and MISO from multiple balancing authorities.

[14] The timing of such incremental expansion is not exact, but here reflects our opinion that one driver for increased renewable energy installations, the EPA's Clean Power Plan, could result in a ramp up in renewable installations over that period.

Long Island and Connecticut, in operation since 2003, is another example, as is the Neptune line between PJM and Long Island.

Transmission zones specifically dedicated for renewable energy can help, but can still result in extended project times. The MISO MVP ("multi value projects") program, for example, proposes to take 10 years (2007-2017) to get $5-10 billion of transmission in place in order to facilitate approximately 10,000 MW of new wind. In Texas, the CREZ ("competitive renewable energy zone") program was mandated by a 2005 state senate bill, and completed construction in 2014 at a cost of $7 billion to facilitate 18,500 MW of wind power.[15]

3.3. Allocate Costs of Transmission Expansions

There is widespread need for new transmission resources across the country, since the location of much of the wind (and some of the solar)[16] resources is different than the locations of most of the older fossil fuel facilities (whose energy output is being displaced, in part, by wind and solar). Such transmission expansions would benefit all ratepayers, and lead to a cleaner and more reliable power system. Distributing these costs accordingly, rather than forcing individual project developers to pay for them, would let a number of relatively smaller (100 MW scale) projects come online.

3.4. Identify Key Weak Points in Grid for the Next Phase of Renewable Expansion

In 2010, the Eastern Interconnection Planning Collaborative (EIPC) initiated a study to analyze transmission requirements under a range of alternative energy futures and to develop long-term transmission expansion plans under these scenarios. The study found that two key pieces of the transmission grid will need expansions in the next decade: (1) new high-voltage transmission lines flowing from the highest class wind regions in MISO and SPP towards the loads in the east, and (2) lower voltage transmission reinforcements to properly support changing power flow patterns as older coal units retire. To better understand what wind and solar additions in the post-2020 timeframe will require, the EIPC study should be updated, accounting for the recent decreases in installed PV and wind costs and an updated forecast of retirements and fossil additions.

---

[15] Public Utility Commission of Texas. 2014. "CREZ Progress Report No. 15 (April Update)." Available at: http://www.texascrezprojects.com/page29605717.aspx.

[16] Solar resources are in general more geographically distributed, and potentially located closer to loads, than wind resources and thus in general will not face the same transmission expansion needs as wind resources.

4. ADMINISTRATIVE BURDENS STALL DEVELOPMENT

New solar and wind installations are carefully located not only to maximize energy production, but to minimize impacts on local wildlife, visual concerns, and other issues. Collaborative working groups have begun to provide data and work with stakeholders to facilitate siting and permitting processes, but this process could be improved. Regulatory requirements vary widely by state, and can change drastically during the development of a project.

4.1. Unclear and Evolving Permitting Requirements Harm Developers

In 2014, Ohio enacted a bill to revise the setback distance to a minimum of 1,125 feet from the nearest property line, a substantial increase in the amount of land for a new wind farm. Several proposed wind farms were immediately off the table, and had the Blue Creek Wind Farm not been grandfathered in, only 12 of its 152 turbines would have been able to be built.[17]

4.2. Use Energy Zones to Streamline Permitting and Regulatory Approvals

While identifying resources is helpful, the key characteristic of a successful program is streamlining the permitting approvals process. One technique to streamline the process is by zoning, which essentially pre-approves a site for future build-out. The state of Rhode Island has designated Renewable Energy Zones pre-established by the state's Coastal Resources Management Council that are designed to minimize potential impacts and improve permitting from state organizations.[18] Numerous other states (including Hawaii, Maine, Iowa, Nebraska, Nevada, Utah, and Washington) have attempted to create similar zones.

In addition to state regulations, offshore wind is also subject to federal regulations from the U.S. Army Corps of Engineers to ensure the project complies with the Endangered Species Act and the Magnuson-Stevens Fishery Conservation and Management Act. The federal government could streamline this process with a broad set of similar Renewable Energy Zones that would give project developers more certainty of approval and lower application costs. In fact, such actions have already begun—the Western Solar Plan, a program developed by the Bureau of Land Management, developed a Programmatic Environmental Impact Statement to facilitate rapid yet environmentally responsible utility-scale solar energy development in six Western states. With the additional help of Solar Energy Zones that identify

---

[17] Kowalski, Kathiann. June 19, 2014. "Industry: Setback changes will end new wind farms in Ohio." *Midwest Energy News*. Available at: http://www.midwestenergynews.com/2014/06/19/industry-setback-changes-will-end-new-wind-farms-in-ohio.

[18] Connecticut Law Review. May 2013. "Second Wind: A Legal and Policy-Based Evaluation of the Block Island Wind Farm and the Legislation that Saved It."

preferred locations, the first three projects under this plan were permitted in less than six months, compared to a typical timeframe of 18-24 months.[19]

4.3. Is Rooftop PV the Solution?

Permitting challenges can be significantly reduced for distributed solar PV, but even for this technology they can make a difference. While the costs of producing PV modules have declined drastically in the past several years, "soft" costs, including permitting, have not followed suit. A recent study found that variations in local permitting and regulatory procedures can lead to an 8 percent price impact.[20] When a homeowner chooses to install PV, they are often required to get multiple approvals that the installation meets local codes, pay a permitting fee, and get interconnection approval from the local utility. The study found 18,000 different authorities with jurisdiction over PV permitting in the United States. By developing comprehensive legislation to streamline and simplify this permitting process, states can have a real impact on the installed cost of solar power.

To address this challenge, New York State developed an optional "Unified Solar Permit." A small incentive ($5,000-$10,000), coupled with increasing accuracy and quality of applications resulting from a streamlined process, was enough to facilitate adoption by over 60 cities and towns.[21] Despite the high-profile nature of siting challenges for utility-scale wind and solar projects, balance of system costs are a much higher fraction of the total installed costs for distributed PV.[22]

A streamlined but voluntary process such as New York's, but on a wider regional or national basis, could facilitate a rapid increase in residential PV development.

5. UNCERTAIN RENEWABLE POLICIES WEAKEN INCENTIVES

Another key barrier to increasing investment in wind and solar energy throughout the country stems from uncertainty regarding federal and state-level programs and policies designed to incentivize growth in renewables. Surprisingly, although these policies—such as the federal Investment Tax Credit (ITC) and

[19] Bureau of Land Management. 2014. "BLM Reaches Major Permitting Milestone for First Projects under Western Solar Plan." December 8, 2014. Press release. Available at: http://www.blm.gov/nv/st/en/info/newsroom/2014/december/southern_nevada__blm.html.

[20] Brukhardt, J., R. Wiser, N. Darghouth, C.G. Dong, J. Huneycutt. September 2014. "How much do Local Regulations Matter?: Exploring the Impact of Permitting and Local Regulatory Processes on PV Prices in the United States." Lawrence Berkeley National Laboratory.

[21] NY-SUN PV Trainers Network. 2014. "NYS Unified Solar Permit." Presentation on October 3, 2014. Available at: http://cnyenergychallenge.org/wp-content/uploads/2014/10/3_CUNY_Schnell_NYS-Unified-Solar-Permit.pdf.

[22] Massachusetts Institute of Technology. 2015. *The Future of Solar Energy*. Page 86. Available at: https://mitei.mit.edu/futureofsolar

state-level Renewable Portfolio Standards (RPS)—provide important financial incentives essential to growth in the industry, they also may hinder renewable growth due to their uncertain futures.

5.1. Federal Tax Credit Ambiguity

The potential positive impacts these policies can have are best shown by a recent study that found federal tax incentives are currently the most important driver of the improving economics of solar energy in New England.[23] Although the physical costs of solar panels and the installation costs for these technologies are continuing to decline at a rapid pace, it is the added economic benefit of the federal ITC that makes installing rooftop solar panels a no-brainer. Nevertheless, there has been much uncertainty around the future of the ITC. As a result of political jockeying, the continued existence of the ITC is in jeopardy. For instance, just two years ago, the ITC was set to expire before a late-night Congressional session extended it at the last minute.

This uncertainty has far reaching effects in the industry, and impacts both solar and wind growth. First of all, the threat of a possible expiration of the ITC led to an unsustainable boom in solar and wind investments in the fourth quarter of 2012, followed by a sharp decline in demand for these projects. The American Wind Energy Association points out that wind installations in 2013 dropped by 92 percent from 2012, a decline that "can be attributed to the late extension of the PTC [Production Tax Credit] and ITC."[24] Such instability is difficult to plan for, and places the businesses and professionals that install these systems in a very tough situation. With the wind ITC and PTC having just expired at the end of 2014, will Congress change its mind and renew the credits? And if the solar ITC expires as planned at the end of 2016, then what future will these companies have? There is no way for installers or manufacturers of solar panels or wind turbines to know whether another tax credit will take the place of the expired ITC, or whether another policy—such as a national carbon tax—will further shift the economics of the electric industry to favor renewable generation. As such, it is difficult for these companies and employees to plan for the future.

5.2. State-Level RPS Policies

The future demand for renewable technologies is further muddied by the changing dynamics of state-level RPS policies. Although 28 states currently have some form of mandatory renewable targets in place that should guarantee the need for renewable growth well into the future, nearly every policy is unique in the types of targets established as well as in the type and level of financial incentives offered for various technologies in state. This inconsistency in the economics of renewable technologies across

---

[23] ICF International. February 2015. "Economic Drivers of PV Report for ISO-New England." Available at: http://iso-ne.com/static-assets/documents/2015/02/icf_economic_drivers_of_pv_report_for_iso_ne_2_27_15.pdf.

[24] American Wind Energy Association. January 2014. "AWEA U.S. Wind Industry Fourth Quarter 2013 Market Report." Available at: http://awea.files.cms-plus.com/FileDownloads/pdfs/AWEA%204Q2013%20Wind%20Energy%20Industry%20Market%20Report_Public%20Version.pdf.

state boundaries creates a difficult business situation for installers who are forced to juggle multiple policies and incentives if they wish to compete in more than one state, severely hindering growth potential.

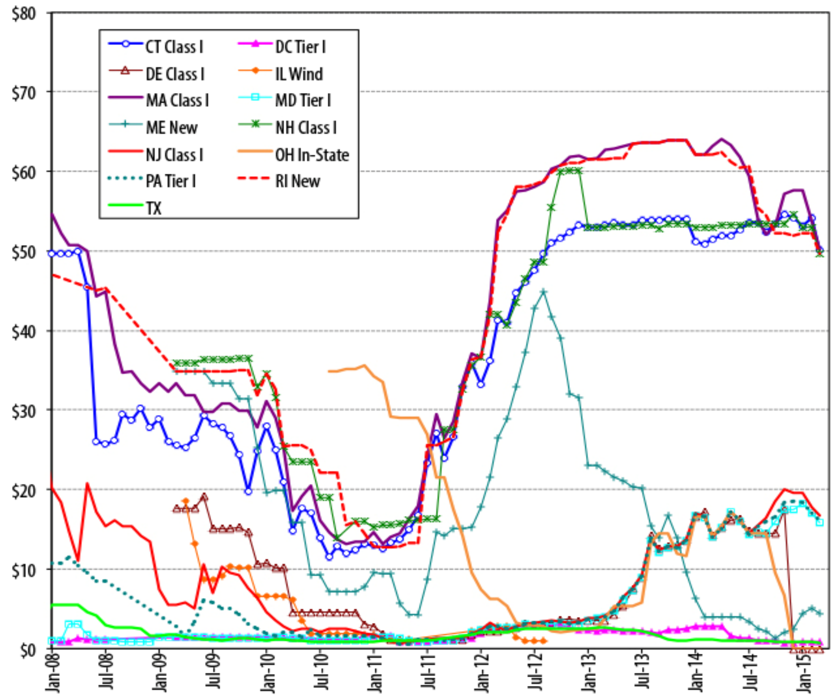
Uncertain Targets

A number of state legislatures around the country have begun to call into question the renewable targets in place in their states. For instance, in 2014, Ohio's state legislature passed Senate Bill 310, which froze the state's Alternative Energy Portfolio Standard. Although the freeze is technically only in effect for two years—maintaining the targeted level of renewable generation from 2014 in both 2015 and 2016—the post-freeze future of renewables in Ohio is uncertain. On one hand, the freeze may be extended permanently into the future, leaving the renewable industry without much incentive to operate in Ohio into the future. On the other hand, the freeze may be lifted, and the state may still strive to achieve 12.5 percent renewable generation by 2027, creating a significant swing in possible futures for the industry in Ohio. Further complicating issues is the fact that the future of the freeze is likely up to the results of a legislature commission study on the topic that has yet to be completed. As other large states see similar issues arise in achieving state goals, the future of the renewable industry in those states is placed under considerable stress. West Virginia became the first state to repeal its RPS policy in February 2015, followed by Kansas in May.

Uncertain Prices

The inconsistency among state policies and renewable requirements leads to an uncertain future for another significant driver of the economics of renewable energy: the price paid for renewable energy credits (REC). North Carolina, which has relatively low levels of installed renewable capacity and is the only state in the southeast of the United States with an RPS, allows compliance through purchasing RECs from any other state. The price paid will differ widely based on the state purchased from, which is dependent on both the renewable energy economics in the state and its RPS policy. Figure 4 below demonstrates how widely these prices fluctuate on the spot market. This instability of REC prices has an impact both on ratepayers in North Carolina as well as developers across the country, who may not be able to accurately assess the economics of new wind or solar projects. Most utilities purchase RECs based on long-term contracts to avoid this uncertainty, but the variation in the spot market shown below demonstrates how much the price of those contracts could vary, depending on when they are signed.

Figure 4: Monthly REC prices by state



Source: DOE Green Power Markets. April 2015. Available at: [http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=5.](http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=5)

Create Stable Incentives

There are, however, a number of options to mitigate this uncertainty, and to allow these federal and state policies to revert back to being a beneficial driver of renewable growth in this country. For one, if the federal government were to revise the ITC again, a better option than a one- or two-year extension might be to draft a glide-path plan that establishes a future path for federal tax credit incentives, ramping down the level of the tax credit over time. Such a policy revision would afford installers and manufacturers alike certainty over the future of the industry.

Another option for mitigating the barrier posed by uncertainty with state and federal policies would be to increase, or even require, consistency among state RPSs. While federal tax policies are a first step in this direction, merely improving consistency across state lines when it comes to the types of renewable targets established and the financial incentives offered could be a huge stabilizing factor in the renewable industry.

6. RATE DESIGN IMPACTS DISTRIBUTED GENERATION

6.1. How Are Rates Designed?

Most electricity customers pay for their electricity consumption using a two-part or three-part tariff, depending on the customer class. Residential customers typically pay a monthly fixed charge (e.g., $9 per month) plus a variable rate based on usage (e.g., $0.10 per kilowatt-hour). The fixed charge (sometimes called the "customer charge") is generally designed to recover the costs to serve a customer that are largely independent of usage, such as metering and billing costs, while the variable rate reflects the cost to generate and deliver energy.

Commercial and industrial customers frequently pay for electricity based on a three-part tariff consisting of a fixed charge, a variable rate, and a demand charge. The demand charge is designed to reflect the maximum amount of energy a customer withdraws at any one time, often measured as the maximum demand (in kilowatts) during the billing month. While the fixed charge is still designed to recover customer costs that are largely independent of usage, the cost to deliver energy through the transmission and distribution system is separated from the cost to generate energy through the use of separate demand and energy charges.

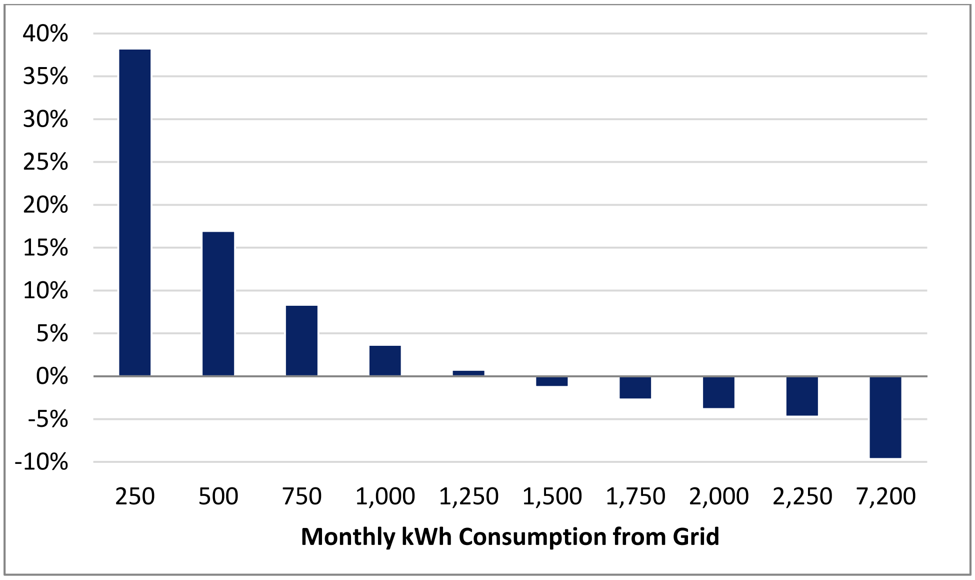
Recently, there has been a substantial increase in the number of utilities that are proposing to recover more of their costs through monthly fixed charges rather than through variable rates. Increased customer charges are attractive to utilities because they reduce risk to the utility from fluctuations in sales due to energy efficiency, distributed generation, weather, economic downturns, or other factors. However, higher fixed charges have a detrimental impact on customers who wish to generate their own electricity through distributed generation.

6.2. Rate Design Can Stop Rooftop Solar Investments

A fixed customer charge reduces incentives for customers to invest in solar and other distributed generation. It sends the signal that customers have no control over a large portion of their bill, as they will have to pay the fixed charge regardless of how much electricity they consume or generate. Since only the variable component is avoidable, increasing the fixed charge makes it more difficult for customers to reduce their electricity bill by reducing their energy consumption from the grid.

For example, consider the impact of increasing the fixed charge for residential customers from $9.00 per month to $25.00 per month, with a corresponding decrease in the cost per kilowatt-hour. A customer that consumes 1,250 kilowatt-hours per month would see virtually no change in their monthly bill, while a customer that consumes from the grid only 250 kilowatt-hours per month due to installing solar panels would see their bill increase by nearly 40 percent (see Figure 5). Kansas City Power & Light recently proposed this increase in the fixed charge,[25] and similar increases in fixed charges were approved last year for several Wisconsin utilities.

Figure 5. Illustrative customer bill impact due to increasing fixed charge from $9 to $25



6.3. Equity and Cross-Subsidization

It is often claimed by utilities that fixed charges are needed in order to ensure that customers with distributed generation pay their "fair share." However, increasing the fixed charge by itself does nothing to evaluate or recognize the full value of distributed resources. Accounting for the true costs and benefits of distributed resources would require an avoided cost study, and any additional costs imposed on the system by distributed generation are likely to be very small at low levels of penetration.

In addition, higher fixed charges can increase cross-subsidization in other areas. By reducing the cost per kilowatt-hour and increasing the fixed charge, low-usage customers will see their bills increase, while high-usage customers will experience bill decreases. Low-income customers will be impacted disproportionately by the new rates, as these customers tend to be low-usage customers.[26] Further, such rates also cause customers in apartments and dense housing to pay a disproportionate share of system costs, since these customers tend to impose lower fixed costs per customer.[27]

---

[25] Missouri Public Service Commission Docket ER-2014-0370.

[26] In a 2009 presentation to the Utah Demand-Side Management Working Group, Jim Lazar noted that approximately 70 percent of low-income customers use less than the average residential monthly usage. See: Lazar, J., *Rate Design Options and Revenue Decoupling*, presentation on January 8, 2009.

[27] Lazar, J. April 2013. *Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed.* Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6516.

7. SUMMARY

The U.S. power grid is in a state of rapid flux, particularly over the next decade as a large number of older fossil fuel fired units retire. The EIA projects another 40 GW of coal retirements in the next two years, and further retirements are likely as other environmental regulations related to water and air quality are finalized—not to mention the soon-to-be-finalized Clean Power Plan. A recent Synapse analysis concluded that a full 77 percent of coal capacity is uneconomic compared to a market price set by natural gas, when accounting for upcoming required environmental control investments.[28]

Wind and solar costs have fallen dramatically over the past decade, and these technologies are poised to make up for much of the energy of retiring fossil units. The originally aggressive scenarios in studies such as PJM's Renewable Integration Study and NREL's Eastern and Western Renewable Studies done several years ago—which called for hundreds of megawatts of new wind and solar by the mid-2020s—seem more realistic every year. In order to facilitate a smooth transition, and perhaps reach these targets by 2020, a number of technical concerns can and must be mitigated:

- The "duck curve" and system stability concerns are largely mitigated in well-interconnected systems, and further alleviated by the increasing presence of demand response and other smart grid measures.
- Improved balancing area cooperation by system operators is essential to managing higher levels of wind and solar in the near term—and can be achieved at relatively low cost. Substantial progress has already been made in the last 18 months.
- Siting new utility-scale installations continues to be an administrative burden to developers, and stalls many proposed developments. State and federal policymakers should continue to refine and develop innovative mechanisms to streamline the review process, such as pre-defined Renewable Energy Zones, in order to speed up the process.
- Renewable energy credits suffer from an uncertain future and state renewable standards are inconsistent across borders. If state policymakers are able to create more stable incentives, developers will feel more confident that installing wind and solar is financially sound.
- Rate design has an oversized impact on the economics of rooftop PV systems, and regulators need to ensure that it balances the interests of all ratepayers while continuing to encourage new systems.

These problems are all solvable in the near term with existing systems and technologies. Modest improvements to these processes should continue to be made by system operators, state and federal policymakers, and public utility commissions to foster the next wave of wind and solar development.

[28] Knight, P. and J. Daniel. 2015. "Forecasting Coal Unit Competitiveness." Available at: http://www.synapse-energy.com/sites/default/files/Forecasting-Coal-Unit-Competitiveness-14-021.pdf.