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A Clean Electricity Future: Assessing the Role of Wide-Area Power System Operations in Supporting Weather-Driven Renewable Energy in the U.S.

Paul D. Picciano
Pomona College

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Paul Picciano

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Abstract

Over the coming decades, renewable energy sources, namely wind and solar, will need to play a larger role in our nation's energy mix as we seek to lower greenhouse emissions and respond to renewable energy policies and the EPA's Clean Power Plan. This thesis assesses the role of wider-area power system operations in the U.S. as a powerful solution in supporting the integration of these weather-driven, variable energy resources that pose substantial challenges to grid reliability. The expansion and integration of organized electricity markets and transmission networks over wider geographic areas can (1) help reduce net-variability in wind and solar power generation while improving reliability; (2) provide an outlet for over-generation while reducing curtailment; (3) improve resource utilization while enabling resource sharing and lowering electricity costs; and (4) enable low-cost pollution reduction by providing a cheap alternative to fossil-fuel generation. Through power industry assessment, case-study analyses, and modeling research using NOAA's National Energy with Weather System Simulator to compare scenarios of regional expansion versus a nation power system, this paper evaluates the feasibility and role of wide-area expansion and integration in achieving higher levels of variable renewable energy than our current system is capable of supporting.

Table of Contents

List of Figures

List of Tables

List of Acronyms

AB 32: Assembly Bill 32

AC: Alternating Current

BAA: Balancing Authority Area

CAISO: California Independent System Operator

CO_2: Carbon Dioxide

CPP: Clean Power Plan

CREZ: Competitive Renewable Energy Zones

DC: Direct Current

DOE: Department of Energy

E3: Energy and Environmental Economics

EIA: Energy Information Administration

EIM: Energy Imbalance Market

EPA: Environmental Protection Agency

EPACT: Energy Policy Act

ESRL: Earth System Research Laboratory

FERC: Federal Energy Regulatory Commission

GHG: Greenhouse Gas

HVAC: High-Voltage Alternating Current

HVDC: High-Voltage Direct-Current

ISO: Independent System Operator

ITC: Investment Tax Credit

kV: Kilovolt

kWh: Kilowatt-hour

NEMS: National Energy Modeling System

NERC: North American Electric Reliability Corporation

NEWS: National Energy with Weather System (Simulator)

NOAA: National Oceanic and Atmospheric Administration

NREL: National Renewable Energy Laboratory

PTC: Production Tax Credit

PURPA: Public Utility Regulatory Act

PV: Photovoltaic

RETI: Renewable Energy Transmission Initiative

RGGI: Regional Greenhouse Gas Initiative

RPS: Renewable Portfolio Standard

RTO: Regional Transmission Organization

WREZ: Western Renewable Energy Zones

Introduction

The development of the U.S. electric power industry reflects a remarkable response to a complex problem. The need for a reliable, efficient, and cost-effective energy system to power millions of American homes, industries, and commercial practices has spurred a thorough integration of infrastructure and regulation over the past century to create the power grid that exists today. Now, through vast networks of transmission lines, power generators, utilities, system operators, and much more, the electric power system maintains a delicate balance of electricity production and distribution to meet a constantly varying demand. Without such a system, modern life as we know it would not be possible.

The power industry, however, now faces another complex problem that must be resolved. Due to heavy reliance on fossil fuels for energy, power plants fired by coal, natural gas, and oil provide nearly two-thirds of generation, and account for about a third of total U.S. greenhouse gas (GHG) emissions, including 38 percent of all carbon dioxide (CO_2) emissions. As a result, the electric power sector is now the single greatest contributor to GHG emissions in the United States, exacerbating the effects of climate change. Over the coming decades, the same kind of resiliency and innovation that has marked the industry's development thus far is needed to spur major reforms across the grid system to transition to a low-carbon power sector.

Higher levels of renewable energy generation, namely from wind and solar power, will be a critical part of this solution. Deployment of these energy sources has been steadily increasing as costs become more competitive, and legislation at federal and state levels now incentivize, and in some cases mandate, greater levels of renewable power generation. The great majority of these new renewable generators are powered by wind or solar energy— i.e. they are essentially "weather-driven" sources of power generation. However, there are inherent difficulties in integrating these weather-driven sources because they are variable and still to a large extent unpredictable. Our power system requires an instantaneous balance of electrical supply and demand (load), and uncontrollable fluctuations in generation create issues of reliability and physical stress on the power system – potential causes of power failure and damage to infrastructure (Masters, 2013). With this variable and uncertain generation, the power system is forced to maintain higher levels of conventional generation as operating reserves – often large, fossil fuel or nuclear fired power plants that can be controllably dispatched – to ensure sufficient power supply when renewable generation is low. And when there is too much wind and solar generation, the excess generation, or "over-generation", must be curtailed, or wasted – an inefficient and costly practice. These significant issues are major obstacles to achieving and accommodating high levels of variable renewable generation. As improving economics combine with increasing legislative support for higher levels of wind and solar power utilization, solutions to mitigate consequences of their variability and provide the grid with flexibility are needed to support integration.

A myriad of such solutions, physical and institutional, are currently under discussion, and a number of these will likely need to be implemented as an ensemble of solutions across the power industry (E3, 2014). Electric storage, for one, would be an extremely salient tool, especially if applied on a large scale. This technical solution would allow storage of excess power generated when demand is lower than supply, and controlled dispatch when demand is higher, practically eliminating issues of variability. However, unless vast technological advances are made to reduce costs and improve efficiency of storage technology, which are unlikely before 2030, storage is not likely to be feasibly implemented beyond the local distribution level (i.e. residential storage units or electric vehicle batteries) (MIT, 2011). Another potential solution addresses demand-response behavior. By incentivizing consumers of electricity to better match their patterns to the patterns in wind or solar generation, such as through time-of-day electricity pricing, customer loads can be shifted to provide more flexibility for the grid and reduce peak load (E3, 2014).

Another powerful solution can be realized through better utilization and design of organized electricity markets and transmission networks, which play a crucial role in orchestrating efficient power transmission and utilization of our nation's energy resources. This is the solution that will be explored in further depth in this thesis. The issue is that the U.S. power system as it exists today is very regionally divided – a so-called "balkanized grid" consisting of three essentially independent systems, or "interconnections", and a myriad of regional market structures and power-coordinating agencies. Organized electricity markets managed by Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) cover only two-thirds of the U.S. power system (see Figure 1, below). In the remaining areas of the country, power transactions are conducted through less efficient bilateral trades between one buyer and one seller. Even within the two-thirds of the country covered by formally organized regional structures, there will soon be not enough transmission capacity to enable efficient market operations to support a growing electric load and to access remote renewable resources. Moreover, the complicated and balkanized structure of current regulation obstructs regional and interstate transmission expansion. These issues significantly constrain how power resources are shared and utilized, particularly important for renewable sources that are dependent on location, in contrast to traditional fuels that can be physically transported. Through the expansion of organized electricity markets and sufficient integration of transmission across wider areas, the power system could better support variable, weather-driven energy and realize significant benefits.

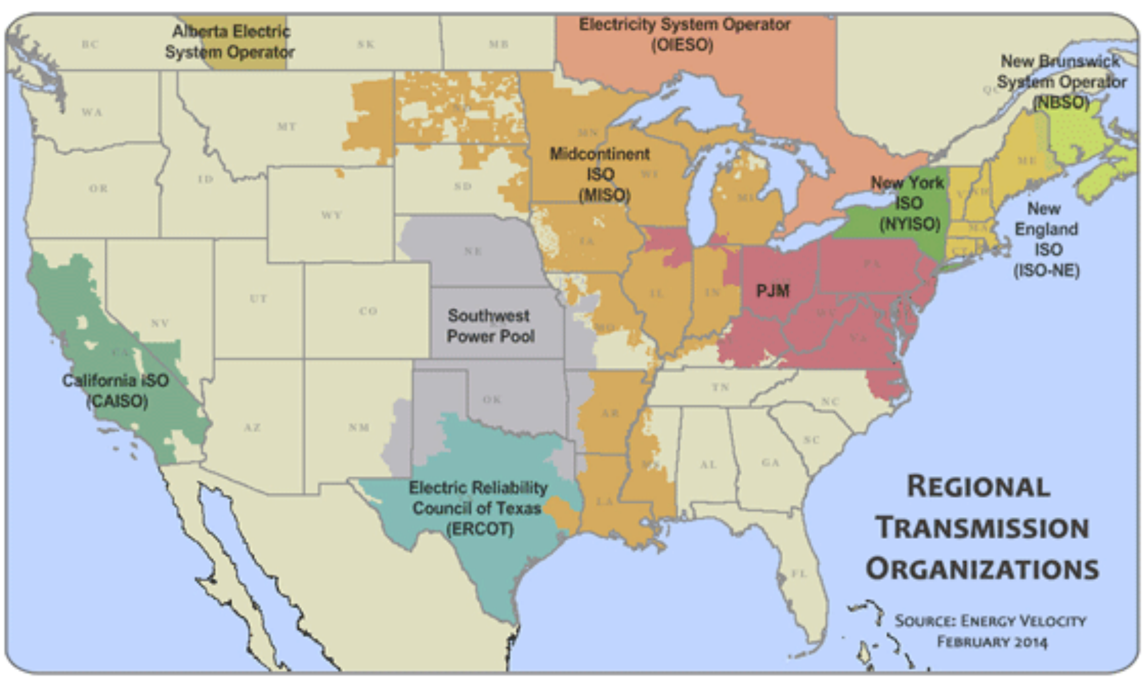


Figure 1: Organized Electricity Markets in the U.S. This demonstrates the scale of regional coverage and the lack of markets in the West and Southeast. (Source: Energy Velocity, 2014)

The first of these benefits can be realized by achieving greater "diversity" of power demand and supply over wider areas. This potential can be best understood by considering how wind and solar weather patterns vary and co-vary with time and geographic scale. While smaller regions might have low levels of wind and solar energy at a given moment, there is high likelihood of higher levels of energy available *somewhere* over a larger area. This phenomenon has been demonstrated with weather and power capacity[1] data by numerous studies, including DOE (2008), Milligan et al. (2012), and Clack et al. (2015). By actually taking advantage of the large-scale variability and diversity of wind and solar resources, large and interconnected regions can enhance the instantaneous availability of these sources, decreasing net-variability in supply, reducing needs for reserves, and improving reliability. Furthermore, by utilizing geographically large and interconnected networks, more wind and solar power can be efficiently shipped more often at low costs from resource-rich areas to locations requiring energy. This creates an outlet for over-generation thereby reducing the need for curtailment of renewables (particularly important with higher penetration levels), improves resource utilization while lowering electricity costs, and enables low-cost pollution reduction by providing a cheap alterative to fossil-fuel generation. Lastly, benefits can be gained from sharing power reserves over the larger regions, which lowers costs and makes market expansion more appealing. Thus, because electric load must only be balanced on aggregate within an interconnected region, weather-driven sources of energy can be more feasibly integrated on a larger geographic scale and through regional coordination.

These benefits can only be realized to their fullest, however, when electricity markets are well designed and have sufficient transmission to efficiently orchestrate power transmission over these larger regions. Compared to electricity markets that are organized primarily around bilateral trading, the operation of electricity markets organized around clearinghouse-based short-term and spot-market auctions allows for a more efficient and timely adjustment of resource up until minutes before the actual physical generation of power. Because wind and solar generation is to a significant extent uncertain, organized

[1] Capacity, whether in reference to transmission and generation, refers to a physical power constraint – the maximum power a given line can withstand and transmit or a given generator is capable of producing at any moment.

markets can more easily and efficiently integrate them by adjusting the planned dispatch of other generation right up to the last minute before actual physical dispatch. Organized markets also bring significant gains from trade, facilitating lower cost dispatch of generation and better utilization of transmission capacity, since they manage generation potential from a fleet of power producers over an area rather than consider trade between a single buyer and seller, as in a bilateral transaction. This latter concept was demonstrated during a significant period of reform during the later 1990s and early 2000s when many of the organized markets seen in Figure 1 were established.

The merits of wide-area power system operations have already begun to emerge as a powerful tool for renewable energy integration in the United States. California has already specifically identified the expansion and integration of its organized market operations as a key solution in achieving its mandated goal of 50% renewables by 2030 (E3, 2015). Since the late 1990s, the California ISO (CAISO) has managed electricity and power in most of California, but there has not been an organized market operator in the rest of the Western region. A recent study by Energy and Environmental Economics (E3) assessing the impacts of higher renewable portfolio standards (RPS) in California showed how "enhanced regional coordination" with more integrated market operations in the region would allow for greater flexibility in power generation, reduce the cost of renewable energy integration, and provide a crucial outlet for over-generation (especially mid-day over-generation of solar) (E3, 2014). In November 2014, CAISO expanded operations into the Western region, integrating many of its operations with PacifiCorp, a major power utility operating in six Western states, to form the Energy Imbalance Market (EIM). Now, the two largest power entities in the Western region coordinate on real-time electricity transactions, which typically take place within 15 to 5 minutes of dispatch, in the West's only competitive, wholesale electricity market. And due to the initial success of the market – saving $21 million in its first eight months of operation – the power companies are now exploring a further expansion of the partnership, and several other utilities are planning to join in coming years. While electricity markets have undergone significant reform and expanded in the past, this represents one of the first major instances driven largely by the need to integrate variable renewable energy.

Beyond regional expansion, the implementation of a national system has also been discussed and its feasibility is currently being assessed more thoroughly. As a so-called “super-highway” or “super grid,” this system would involve installing a new network of transmission overlaid on top of existing regional infrastructure to better enable the operation of a national power market. In fact, researchers at the National Oceanic and Atmospheric Administration (NOAA) have demonstrated how a national network of high-voltage direct-current (HVDC) transmission combined with a significant expansion of wind and solar power generation could enable reductions in CO_2 emissions of up to 80% of 1990 levels by 2030 – with existing technology and at no additional costs (see Figure 2) (Clack et al. 2015). This striking result highlights how the penetration of weather-driven renewable resources can be substantially increased simply by expanding power grid operations and markets to a much larger geographic scale. By enabling connectivity on a national scale with HVDC lines, more wind and solar power can be efficiently and cost-effectively utilized across the country.

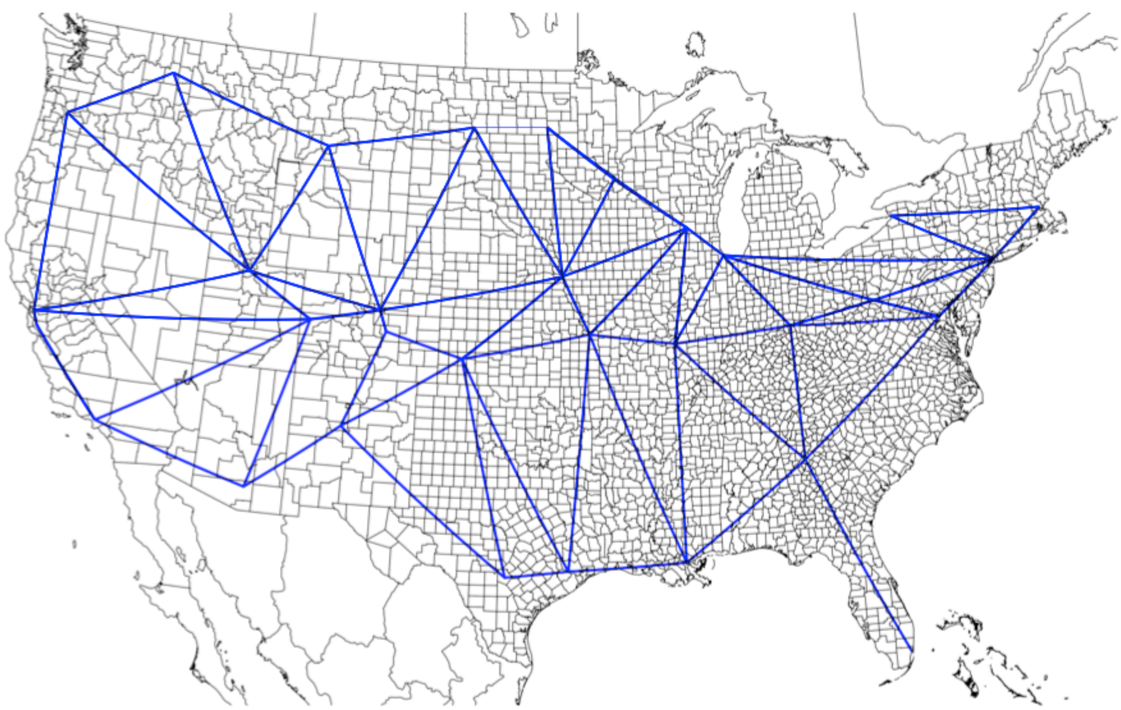


Figure 2: The national HVDC transmission network implemented in Clack et al. (2015).

Despite this potential opportunity, many obstacles stand in the way of the realizing the benefits of wide-area expansion and increased coordination, and this transition presents a blend of physical, economic and institutional challenges. First, to expand regional markets or increase coordination, new infrastructure must be developed to provide greater regional connection and physical capacity to support the resulting power flows. Furthermore, to integrate increased renewable energy generation, infrastructure also needs to be expanded to remote locations to access the richest renewable resource sites. This process of transmission development is not only physically demanding and costly, but also very difficult to achieve under current institutions. Transmission planning of interstate or even intrastate lines is subject to state regulation, involves conflict over the allocation of costs and benefits, and requires compromises among stakeholders and local governance. The merging of interstate market operations will likewise require largely unprecedented cooperation. The Federal Energy Regulatory Commission (FERC), the primary governing body over interstate electricity commerce, has in the past decades and recent years adopted regulations to encourage development of competitive, organized markets and to improve the regional transmission planning process. However, its authority to mandate such changes is extremely limited and much more needs to be done if wider area coordination of markets is to be achieved.

In this thesis, I will assess the institutional, economic and physical implications for encouraging the integration of wind and solar power generation through the expansion of organized electricity markets and transmission networks in the U.S. electric power system. In doing so, I will evaluate the feasibility and role of wide-area expansion and integration as a solution to achieving higher levels of variable renewable energy than our current system is capable of supporting.

Chapter 1 introduces the U.S. power system and concepts regarding variable renewable energy integration. Chapter 2 will discuss the evolution and benefits of organized, wholesale electricity markets in the U.S.; present a case-study analysis of the West's EIM; and consider the idea of a national market system. These notions help build precedents for market reform, establish the fact that achieving a substantial increase in wind and solar generation is an important emerging motivation for grid and market expansion, and seek insight into the process and challenges of achieving further market restructuring and expansion.

While it is clear that wider-area coordination and integration would bring numerous benefits and will be necessary to accommodate higher volumes of wind and solar energy in our power system, the extent of expansion that would be most valuable and cost-effective is unclear. Chapter 3 explores this uncertainty. Using NOAA's National Energy with Weather System (NEWS) Simulator, an advanced model of the U.S. electric system, I will demonstrate the impacts of potential expansion scenarios on both regional and national levels. These efforts attempt to assess the merits of a national market enabled by a national HVDC network in context of the current U.S. power grid and a less intensive regional expansion scenario. By assessing system changes through metrics including renewable energy deployment, electricity costs, CO_2 emissions, and curtailment, I will compare the marginal benefits of regional expansion versus the implementation of a national system. Through this analysis, I provide suggestive conclusions regarding the extent of reform that must occur over the next few decades to achieve higher levels of wind and solar energy integration.

Chapter 4 will then explore the role of transmission expansion and assess the institutional, economic, and physical challenges impeding interstate projects that apply to both the regional and national expansion scenarios. This discussion will highlight prominent barriers to achieving the integration of wind and solar power through wide-area power operations that must be resolved moving forward. Finally, Chapter 5 concludes and identifies future areas for investigation and the next steps necessary to achieve this clean electricity future.

Chapter 1: The U.S. Electric Power System

The electric power grid is a complex system that orchestrates the generation, transmission, and distribution of electrical power to consumers. The current grid infrastructure, specifically for the contiguous United States, spans over six million miles of transmission and distribution lines, involves the coordination of over three thousand electric distribution utilities and over five thousand power plants, and provides energy to over 143 million end users (MIT, 2011). This represents a significant change from when the power system first began to emerge over 130 years ago. Originally, there was no "system", but simply individual generators serving a few adjacent customers. Local systems slowly emerged, frequently serving overlapping territories of consumers. Eventually, it was recognized that overlapping grids were socially undesirable and that, at a minimum, the industry's wires systems should be treated as regulated "natural monopolies" serving local service area "franchises". As the industry grew, power plants and utilities found it economical to connect their lines and share power, leading to the creation of the first transmission networks. And by the 1980s, many utilities had formed regional and interregional networks to serve larger customer-bases at lower costs and more reliably – benefits gained from sharing reserves, access to lower-cost generation, and support in case of system failure (NREL, 2012). Over the past century, this system has grown significantly and now is responsible for producing and distributing over forty percent of the nation's energy supply, a substantial increase from 1949 levels of fourteen percent (MIT, 2011).

Describing the electric power industry and all its intricacies would be a long endeavor going well beyond the purpose of this chapter. Instead, this chapter is intended to explain only those aspects of the system that are necessary and relevant to understanding the U.S. power system and how it operates for the purposes of this paper, as well as to introduce key concepts of renewable energy integration in this context. By detailing grid infrastructure and market operations, I will lay the foundations to understand the key challenges and possible solutions discussed in the following sections of the paper, which contain the heart of the research and analysis.

1.1: The Grid: Key Players

The current grid consists of numerous levels of divisions and entities, including, but not limited to: transmission and distribution networks (distinguishable by voltage and function), wholesale and retail electricity markets, wholesale market operators, local utilities, competitive retailers, and reliability regulators. At the highest geographic level, the most obvious institutional separation is among three main grid interconnections, each of which operate independently of each other as essentially separate grids, with exception of very minimal power sharing via a handful of direct-current (DC) lines (see Figure 3). A myriad of regional market structures and power-coordinating agencies are spread across these interconnections, including organized wholesale markets coordinated by ISOs and RTOs, and domains of various other utility and power supplying structures, including investor-owned utilities, government-owned utilities (municipal, state, federal levels), and non-profit cooperatives. While two-thirds of the U.S. population and electric load is met through the organized markets operated by ISOs and RTOs, as seen previously in Figure 1, power markets in the Southeast and West are operated primarily through vertically integrated or government-owned utilities. At the federal level, the Federal Energy Regulatory Commission (FERC) is the primary governing body over wholesale electricity markets and interstate electricity commerce. However, states are primarily responsible in matters of retail sales and operations. This regional mix of regulation and ownership structures is largely due to the historical evolution of the industry and, so far, a lack of sufficient political will or motivation to superimpose a stronger national policy over these local and regional structures (MIT, 2011).

Further divisions of the power system include the North American Electric Reliability Corporation (NERC) regions and Balancing Authority Areas (BAAs), as portrayed in Figure 4. Currently, there are about 130 Balancing Authorities (more often called "control area operators") across the U.S, each of which are responsible for ensuring that the electric load is matched by supply at all times in their respective "balancing areas" (MIT, 2011). Power can be shared between balancing areas, but each local operator is first and foremost required to maintain the balance within its own area. Due to the uncontrollability of electrons (which follow the path of least resistance), balancing areas

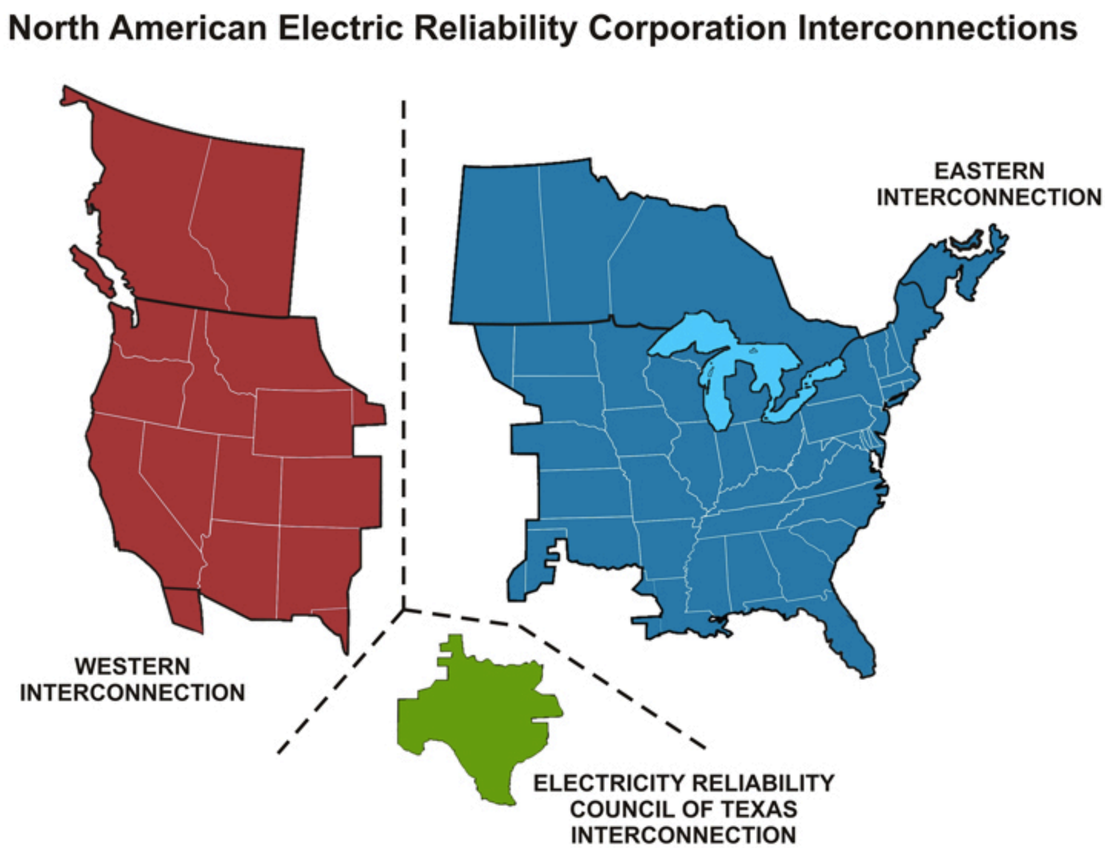


Figure 3: The three major power interconnections, independently synchronized, forming the U.S. power grid. (Source: Department of Energy)

attempt to direct the transfer of electric through a process called power wheeling, which involves raising or lowering generation at different locations. It has been estimated that about 40% of demand in each area is still balanced by local generation, despite the interconnections with other balancing areas (Cicala, 2015). To monitor and ensure larger grid reliability, the NERC[2], which operates under the authority of the FERC, develops and enforces compliance of most of the operational, reliability, and security standards. There are now eight regional entities in the U.S. As Figures 3 and 4 suggest, a larger grid exists at the North American level, with connections with Canada and Mexico. However, the international political divisions inherently impose constraints that limit interconnection and coordination, and this paper will maintain a focus on the contiguous U.S. system.

[2] The NERC was established by the FERC in 1968 in response to a major blackout in 1965 in the Northeast U.S. with the objective to ensure reliable and stable energy supply in the grid (Masters, 2013).

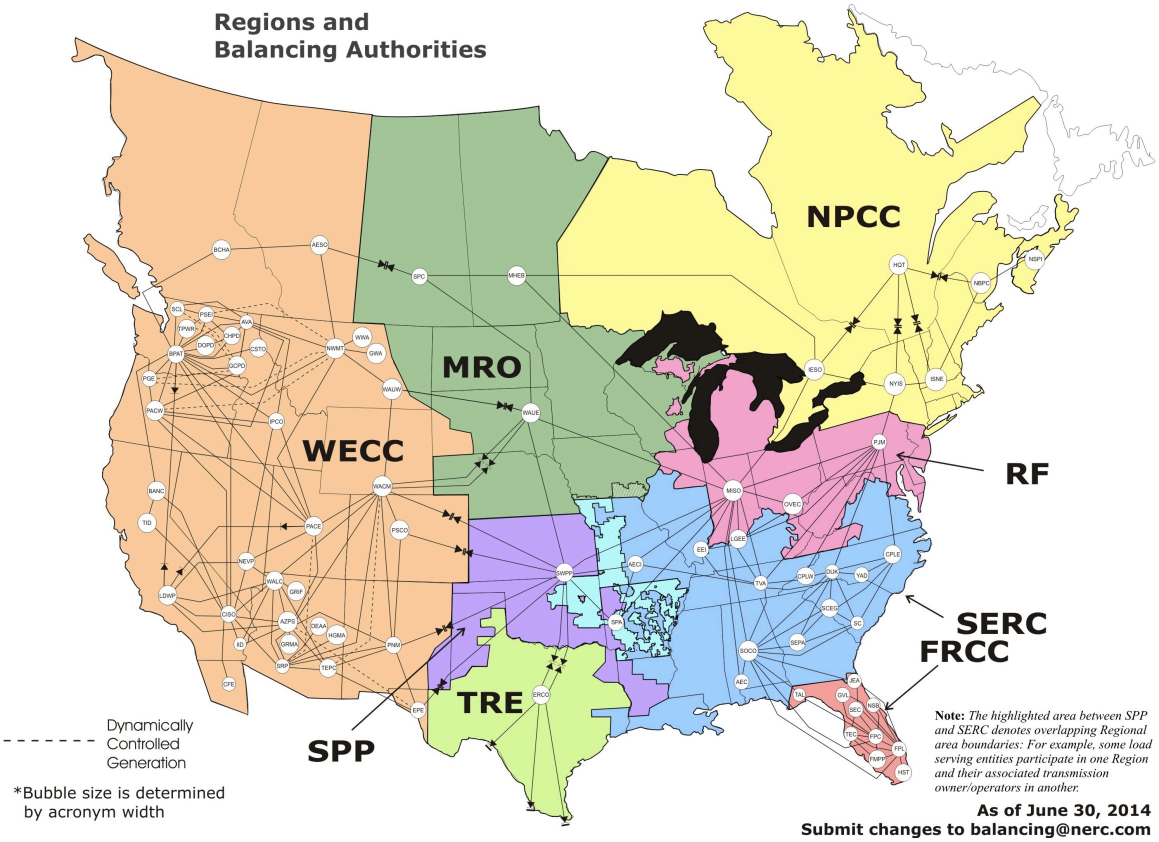


Figure 4: North American Electric Reliability Corporation Regions and Balancing Authority Areas. (Source: NERC, 2014)

Lastly, it is important to briefly discuss the concept of reserve-sharing groups. To ensure the reliable operation of the system, networks require a buffer in terms of capacity available above the projected annual peak load, often around 12-15% (NREL, 2012). There are several classes of "reserves" for different purposes, including spinning and non-spinning reserves, and operating and planning reserves. Importantly, interconnected balancing areas and utilities can form groups through which they can aggregate resources and reduce their need for maintaining total reserve capacity. This is a significant motivation for integrating the grid over larger geographic areas.

1.2: Wholesale Electricity Markets and Operations

A wholesale electricity market is a system that orchestrates the generation and transmission of electricity between generators and retailers, or "sales for resale." In comparison, retail markets link these distributors to end-use customers such as households or commercial buildings in final sales. Whether a transaction is considered a wholesale transaction or a retail transaction depends entirely on the identity of the power purchaser. If the power purchaser is an entity that resells the power to another party then the transaction is a wholesale transaction. If the purchaser is an end-user who uses the power to do work such as operating an appliance, then the transaction is a retail transaction. Two distinct market structures currently facilitate wholesale electricity transactions: central, organized markets; and decentralized, bilateral markets.

Organized electricity markets currently cover about two-thirds of the system's electric load, a significant increase from 1999 levels of about 10% (Cicala, 2015). While regulated by the FERC under the Federal Power Act (1935), these organized wholesale markets are managed by independent entities – ISOs and RTOs – that play the central role in orchestrating these transactions between generators and power-purchasing utilities, dispatching the lowest-cost units first to reliably meet demand. This dispatching process is completed through an automated auction in which suppliers and purchasers submit price bids in several temporal market phases (typically, day ahead, hour-ahead, and real-time). Because demand must be met instantaneously, generation and trading requires advanced planning (Mansur and White, 2012).

First, generating units are committed in a day-ahead market, which typically facilitates the highest volume of transactions (Mansur and White, 2012). These often entail scheduling large fossil fuel or nuclear-fired power plants that require significant time to change output. Each generator submits a selling price, and the market operator constructs a "merit-order" of submitted bids ordered from lowest to highest. Those units with the lowest bids whose prices fall below the amount needed to meet demand are scheduled for dispatch. This merit-order, however, does not reflect the final commitment. During the day of generation, hour-ahead and real-time markets (up to minutes until dispatch depending on the region) enable changes to dispatch units that more appropriately respond to demand at the cheapest costs. This is important because it gives more flexibility to grid operators, and can allow for deployment of, for example, quick natural gas turbines or renewable energy sources whose generation levels are better known in the closer time frame. Known as economic dispatching, this multi-phased process is only possible because independent, centralized operators manage the dispatch of the entire fleet of generators and have the ability to assess decisions in the context of the needs of the entire network.

In contrast to these market-orchestrated operations, the remaining power transactions are conducted through bilateral trades. These involve scheduling trades through either manual means of communication, such as telephone calls, or pursuant to pre-existing power purchasing agreements, which ensure generators a fixed price for electricity over a predetermined period of time. As seen earlier in Figure 1, the majority of the West and Southeast are the last remaining regions without any form of organized markets, and thus are largely driven by these bilateral transactions. Without a central, coordinating entity, these transactions are not typically conducted in a sub-hourly timeframe, and the inability to facilitate the most cost-effective and efficient trades over a region makes it difficult to appropriately dispatch the lowest-cost units, resulting in significant "out-of-merit" losses. This issue will be a matter discussed in greater detail in Chapter 2.

1.3: Transmission Infrastructure

The power transactions facilitated by wholesale markets would not be possible without the infrastructure to transmit electricity. Transmission refers to the high-voltage circulation of power between generators and distributors – the bulk power system, which must be distinguished from distribution, which refers to the supply of electricity to end-use customers. There is a substantial difference in the infrastructure and operations of each process. During transmission, voltage must be stepped-up from generation to very high levels (between 200 and 765 kilovolts (kV)) in order to minimize power losses[3] [4]. For distribution, however, the voltage must be stepped back down at substations to safe

[3] Today, about 7 percent of power generated is lost before it reaches final customers. This is an improvement from the 1920s, when levels were around 16% (MIT, 2011). These losses result largely from heat, and represent a significant physical constraint.
[4] Power is the product of voltage (the electrical force) and current (the rate of electricity flow). Losses are proportional to current-squared, so at a given power level, stepping up voltage will reduce current by the same factor, while maintaining power supply and reducing power losses by that factor squared (Masters, 2013).

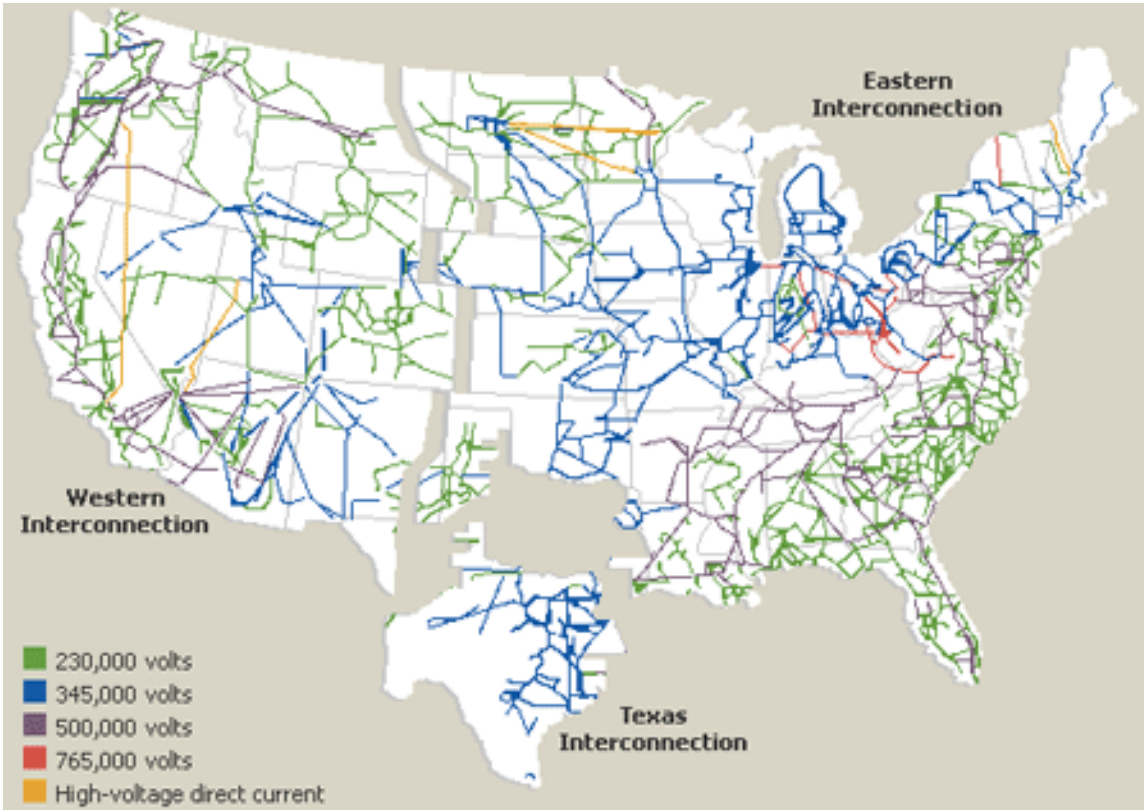


Figure 5: Transmission lines in the U.S., broken down by voltage. Orange represents HVDC, while the remaining colors are HVAC. (Source: EIA, 2014)

and usable levels for customers, at a standardized frequency of 60 Hertz. Furthermore, while there are over three thousand entities that operate at the distribution level, only a few hundred control and orchestrate transmission, owned for the most part by investor-owned utilities, but also federal, public-owned, independent, and cooperative entities. Similarly, while there are nearly six million miles of distribution lines, which are constructed for lower voltages and often disperse radially from load centers, there are about 170,000 miles of transmission lines made for 200 kV or higher that connect generation and distribution (MIT, 2011). Unlike the distribution system, the transmission system contains more redundant paths along which power can flow. Consequently, if there is a failure of a single transmission line, customers will likely not notice because power will be automatically routed across the remaining redundant transmission paths so that an area-wide blackout will be averted. However, local distribution circuits contain much less redundancy so that an outage of a distribution line will usually result in a blackout of many customers in a confined local area (MIT, 2011). In this paper, I specifically focus on these high voltage transmission networks – the underlying infrastructure that enables the operation of wholesale electricity markets.

Transmission infrastructure and technology has changed significantly since the power industry first began, and will continue to change further. In the 1880s, Thomas Edison designed and built the Pearl Street Station in New York City, the first local electric power network serving multiple customers. However, because he championed the use of DC power, his system could only transmit power at a low-voltage and over short distances without significant power losses. After the alternating-current (AC) transformer became a viable technology in the 1880s to change AC power voltages (but not DC), George Westinghouse demonstrated the ability to ship power longer distances with high-voltage alternating-current (HVAC) transmission in his 1896 project connecting hydroelectric power in Niagara Falls to Buffalo, New York. Following his "victory" over Edison, Westinghouse's HVAC became the predominant transmission technology, with exception of a few HVDC lines, such as the 850 mile Pacific DC Intertie connecting the Pacific Northwest and Southern California, and some low-voltage DC lines connecting the three large U.S. interconnections (Masters, 2013). Because these interconnections are independently synchronous (i.e. they operate with slightly different frequencies), the AC-DC-AC conversion provides a viable way for transmitting power from one independently synchronous interconnection to another without the grids matching exact frequencies.

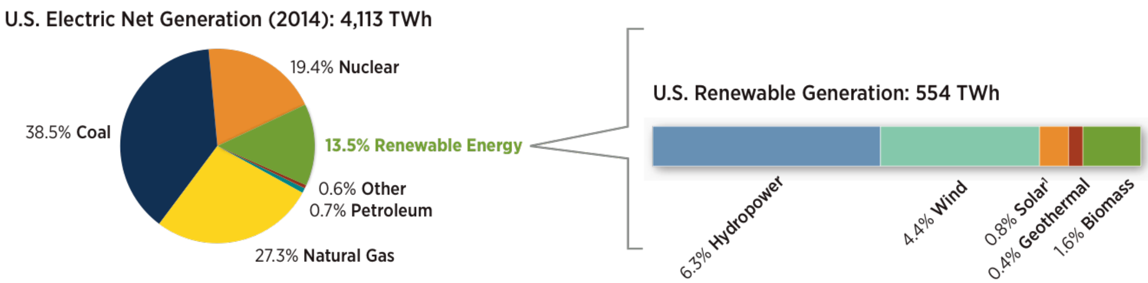
Ironically, the use of DC transmission now might be needed for long-distance lines to access remote renewable resources as well as constructing a national overlay system, if such a project is pursued. Over longer distances (over 300 miles), HVDC transmission has fewer power losses than HVAC and is cheaper per-mile. While DC-to-AC converter stations increase capital costs, the benefits gained over longer distances compensate. Additionally, these lines are ideal for point-to-point transfers as in either case above, and enable more direct and reliable power transmission (MIT, 2011). In the case of a national system, HVDC lines also would easily allow power transfers across the independently synchronous interconnections, which would not be possible by simply expanding existing HVAC infrastructure.

1.4: The Integration of Weather-Driven Renewable Energy

The U.S. Renewable Electricity Sector: Current Trends & Drivers:

Renewable energy sources currently play a small role in the generation of electricity in the U.S. In 2014, as seen in Figure 6(a), renewables accounted for around 13% of all electricity generated, largely from hydroelectric and wind. Figure 6(b) shows the break down of major categories of sources and generation shares from 2004 to 2014. While current levels of wind and solar penetration are low, they reflect a major shift in the past decades, particularly with respect to wind and solar deployment. From 2000 to 2010, wind capacity increased over 15-fold, from 2.6 GW to 40 GW, and today there are 65 GW installed with another 13.6 GW in development (NREL, 2012; DOE, 2015). Wind generation has also increased dramatically, tripling between 2008 and 2013 to 168 GWh and leading the U.S. to be the greatest producer of wind power in the world (EIA, 2014). Utility-scale solar has also increased significantly, although it still contributes a smaller share of the energy mix. From nearly zero capacity in 2008, there was about 10 GW by 2014, and now there is another 27 GW in development (DOE, 2015). Solar capacity additions in 2014 accounted for nearly half of all renewable electricity installations, demonstrating its prominence among other renewable sources (Beiter, 2015). Importantly, there is significant regional variety. For example, while in 2010 non-hydro renewables accounted for 4.2% of generation, they accounted for 13.7% in California (MIT, 2011).

Two key factors driving this transition are decreasing costs and increasingly favorable legislation. First, primarily through research and development and learning-by-doing, the costs of wind and solar have plummeted over the past decade into cost-competitive ranges. Solar costs dropped by nearly 60% from 2008 to 2014 to $2.34 / Watt (W), and wind likewise has dipped below 10 cents / Kilowatt-hour (KWh) (DOE, 2015). This has incentivized significant investment in the deployment of renewable energy technologies across the country over alternative generation sources. Secondly, electric sector policies favoring both renewable generation and reduced GHG emissions have become more stringent over time and have played a strong role in the greatly increased adoption of clean energy generation. At the federal level, the Renewable Electricity Production Tax



(a)

	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Gases	Nuclear	Renewables[1]	Other	Total Generation (GWh)
2004	49.7%	2.5%	0.5%	17.8%	0.4%	19.8%	8.8%	0.4%	3,979,032
2005	49.5%	2.5%	0.6%	18.7%	0.3%	19.2%	8.8%	0.3%	4,062,583
2006	48.9%	1.1%	0.5%	20.0%	0.3%	19.3%	9.5%	0.3%	4,072,073
2007	48.4%	1.2%	0.4%	21.5%	0.3%	19.4%	8.5%	0.3%	4,164,743
2008	48.1%	0.8%	0.3%	21.4%	0.3%	19.5%	9.3%	0.3%	4,126,995
2009	44.4%	0.7%	0.3%	23.3%	0.3%	20.2%	10.6%	0.3%	3,956,877
2010	44.7%	0.6%	0.3%	23.9%	0.3%	19.5%	10.4%	0.3%	4,133,671
2011	42.2%	0.4%	0.3%	24.7%	0.3%	19.2%	12.6%	0.3%	4,112,099
2012	37.3%	0.3%	0.2%	30.2%	0.3%	18.9%	12.4%	0.3%	4,061,056
2013	38.7%	0.3%	0.3%	27.6%	0.3%	19.3%	13.1%	0.3%	4,082,706
2014	38.5%	0.5%	0.3%	27.3%	0.3%	19.4%	13.5%	0.3%	4,113,375

(b)

Figure 6: (a) U.S. Electricity generation by source in 2014, including a breakdown of renewables. (b) Generation of major categories from 2004 to 2014. (Source: Beiter, 2015).

Credit (PTC) specifically incentivizes wind generation by awarding wind producers $.023 for each kWh of generation for the first 10 years of a wind turbine's operation. The PTC applies to several other less prominent sources of energy such as biogas, geothermal, and smaller hydroelectric plants, but importantly does not include solar energy. Similarly, the Investment Tax Credit (ITC), also a federal-level corporate tax credit, supports investment of various renewable technologies, most notably a 30% tax break for solar investments. These policies have significantly encouraged wind and solar development since their implementation in the mid-1980s. However, they have undergone cycles of expirations and renewals, and their future is uncertain. In addition to these federal programs, many states provide either similar tax credits or other incentives to promote renewable energy growth (MIT, 2011). And either in addition or as an alternative to incentive-based approaches, twenty-nine states and Washington, DC have enacted RPSs. This legislation *requires* that a minimum percentage or amount of energy sold to consumers by electricity retailers be produced by renewable generation. Until recently, California had demanded a minimum share of 33% renewable electricity generation by 2020, but now has increased this share to 50% by 2030.

Efforts to reduce air emissions in the U.S. have also led to numerous policies that indirectly will require cleaner energy generation and greater renewable energy usage. The U.S. Environmental Protection Agency's (EPA) Clean Power Plan (CPP) regulations issued in 2015 is a nation-wide initiative to reduce CO_2 emissions from the total fleet of U.S. power generation plants. Driven by state-specific implementation plans to meet federally determined emission standards, it employs a flexible approach and aims to reduce nation-wide emissions by 32 percent of 2005 levels by 2030 (EPA, 2015). While the CPP will shape CO_2 emissions in years to come, cap-and-trade programs[5] already regulate CO_2 emissions at the regional and state levels in the Northeast's Regional Greenhouse Gas Initiative (RGGI) and in California pursuant to Assembly Bill 32 (AB 32). EPA policies such as the Mercury and Air Toxic Standards and the Coal Combustion Residuals Rule will likely force early retirement of many coal plants, which will require new, cleaner generation sources (E3, 2015). For a much longer period of time, cap-and-trade programs have also regulated sulfur dioxide emissions nationally, as well as nitrous oxide emissions in the Eastern U.S.

As states respond to incentives and comply with the standards for renewable energy and emissions, renewable energy penetration will continue to increase, especially for wind and solar power. In fact, with current legislation in place, projections by the U.S. Energy Information Agency (EIA) predict that between 2010 and 2030, 57 percent of the increase in generation and 46 percent of the increase in capacity will be due to renewable

[5] Cap-and-trade is a market-based emissions reduction scheme in which a number of permits, each equivalent to a unit of emissions (e.g. ton), are allocated to emission generating entities such that a total cap, or limit, is established. These entities are then allowed to trade permits among themselves, allowing cost-effective reductions in emissions.

energy sources other than hydroelectric. Of these increases, about 50% and 90%, respectively, will be attributed to wind and solar (MIT 2011).

Integration Challenges:

The integration of increasing amounts of variable wind and solar energy resources poses substantial challenges that the electricity industry must resolve in the coming decades. Without affordable electric storage at the utility (grid) level, the short-term and long-term fluctuations in wind and solar generation must be instantaneously offset by alternative generation sources. While current levels of wind and solar generation do not pose significant challenges to grid operations and power supply reliability under most circumstances, higher levels of penetration will become far more problematic as the "net" demand after subtracting the portion served by wind and solar power becomes much more variable and unpredictable.

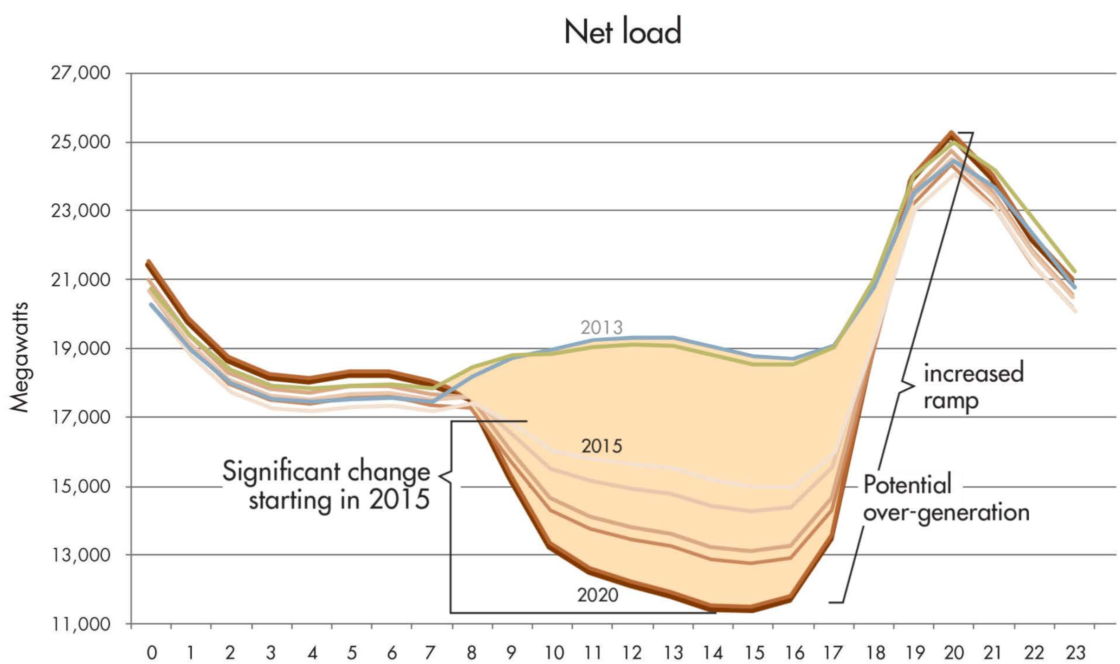


Figure 7: The "Duck Chart" highlighting over-generation and ramping issues due to solar and wind generation in California's power system. (Source: Rothleder, 2013)

Figure 7 above depicts one of the most significant challenges facing grid operations and power supply reliability. The graph, informally dubbed the "Duck Chart" by California stakeholders, shows forecasts of net electricity demand in California in various years after subtracting wind and solar production. Because solar is most prominent during mid-day hours when the sun is shining, it displaces much of the remainder of the generation needed to serve load. However, abrupt changes in solar radiation as the sun goes down results in a significant drop in the amount of solar power that can be generated, forcing other dispatchable sources to step in very quickly. However, there are significant limitations in how fast these generation sources, often fossil-fuel power plants, can change production – a constraint called "ramping" (Borenstein and Bushnell, 2014). As solar power increases in penetration, these ramping challenges will become more severe and potentially cause grid reliability issues or damage to the heavy industrial technology that becomes strained by abrupt changes generation (Masters, 2013). These ramping limitations force individual power plants to maintain generation above a minimum "turn-down" level during these mid-day hours, further exacerbating the issues of solar power over-generation.

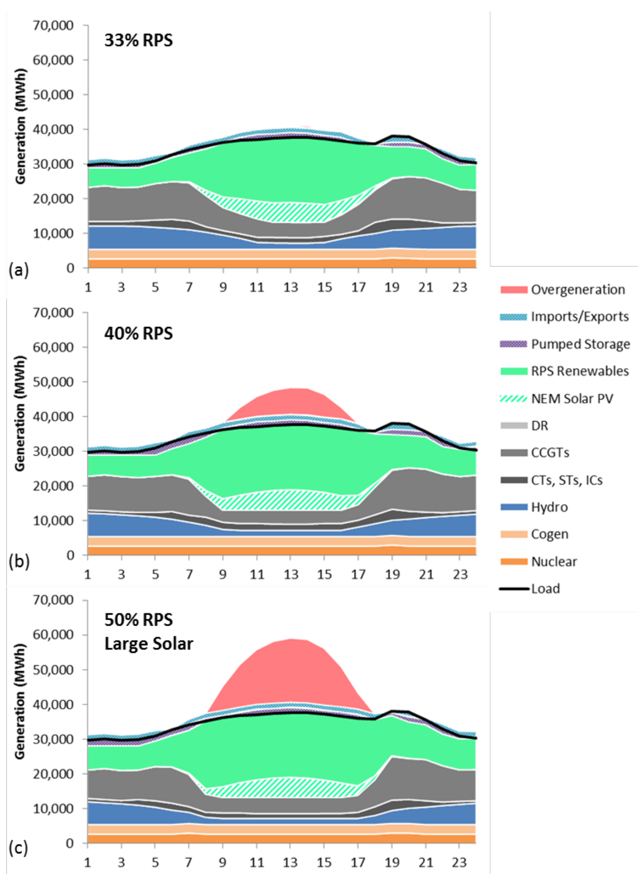


Figure 8: Potential over-generation in California. (Source: E3, 2014)

According to a recent study conducted by E3 in 2014 assessing the impact of higher RPSs in California, over-generation will be perhaps the greatest integration challenge. During mid-day hours when solar generation is at a maximum, risk for over-generation becomes much more likely at higher levels of solar penetration. If solar (or wind) energy generated causes total generation to exceed demand, either something must be done to dispose of this excess power generation or these renewable generation sources will have to be curtailed. Even though their marginal costs are near zero, it is more economical to waste their free energy than shut down power plants that have might have costly start-up expenses, minimum turn down levels, or require long times to turn back on. It some cases, curtailment might be physically necessary regardless of costs to ensure a sufficient power supply that might otherwise be compromised if these power plants are shut down instead.

Long-term, seasonal fluctuations also cause significant concern with higher levels of wind and solar power. If these sources are to account for a majority of power generation and capacity, long periods of time without generation capability would cause major reliability issues and power outages. To prevent this, backup capacity would need to be readily available for dispatch, likely fossil fuel or nuclear power plants. Maintaining these reserves in addition to significant capacities of wind and solar would cause electricity costs to rise significantly, negating any cost benefits from wind and solar themselves (Borenstein and Bushnell, 2014). The inability for these renewables to also completely and independently supply power to meet load also places a constraint on the maximum level of penetration feasible unless economical large-scale energy storage becomes a reality.

Power System Flexibility and Integration Solutions:

To mitigate the challenges of integrating variable wind and solar energy resources, the electric power industry must implement innovative solutions to provide the grid more flexibility in generation or shift demand in response to patterns in generation. Known as supply-side and demand-side strategies, a combination of both will likely need to be implemented to cope satisfactorily with periodic over-generation caused by integrating more wind and solar generation. For a long time, California has been a leader in environmental sustainability and clean energy, and now with a RPS of 50% by 2030, and numerous other environmental regulations, it is preparing to integrate a myriad of solutions to support of high levels of variable renewable energy. These solutions, listed below, are broadly applicable mitigation solutions and reflect responses that can and should be implemented by the rest of the nation in the coming decades. These are the main solutions proposed in the E3 study referenced earlier.

Enhanced Regional Coordination: Pursing greater coordination with other Western states could give California an outlet for over-generation and as well as supply flexibility from imports that could relax ramping constraints.

Renewable Portfolio Diversity: Integrating a variety of renewable energy sources reduces the concentration of generation during particular times of the day. For example, substituting more wind for solar in the generation portfolio could reduce over-generation from solar during the day and increase generation during the night, smoothing net variability and reducing mid-day over-generation.

Curtailment Energy Storage: By capturing electricity generated by renewables rather than curtailing it during times of over-generation, energy from wind and solar can be dispatched at later times. In addition to reducing over-generation, this would reduce the need for reserve capacity. This storage could consist of both on-network storage as well as storage located on retail customer premises.

Demand Response / Flexible loads: Electric demand can be shifted to better match supply through methods such as time-of-day pricing, where electricity prices vary throughout the day in response to load, or charging/dispatching electric vehicle batteries during critical times of the day. (Note that the prices in some wholesale markets have already actually become negative during periods of over-generation.)

Wide-area operations – the integration solution explored in this paper – can be understood through concepts such as "enhanced regional coordination" and "renewable portfolio diversity." The latter, in this case, is achieved by creating access to a diverse renewable selection inherent over the wider geographic area, rather than deliberately selecting new types of generation in the original area, as the E3 study describes regarding California's integration. Over larger geographic areas, the variability of total renewable generation is reduced. The effect is much like investing in a wider range of stocks to reduce the variability in an investment portfolio. For example, consider Figure 9c below, which depicts data from the National Renewable Energy Laboratory's (NREL) Western Wind and Solar Integration Study. The four plots show wind power over four areas, with the top images representing a smaller area within the areas in the bottom plots (NREL, 2012). The y-axis range represents the variability of generation, and the data in the bottom plots show that variability has smoothed considerably in comparison to the corresponding top plot. Figure 9a also demonstrates this same idea. Considering five regional groups from NREL's Western Wind Integration and Transmission Study, the variability (Normalized Sigma) is again reduced with the larger regions (NREL, 2012). Lastly, the study recently conducted by NOAA researchers (Clack et al., 2015)

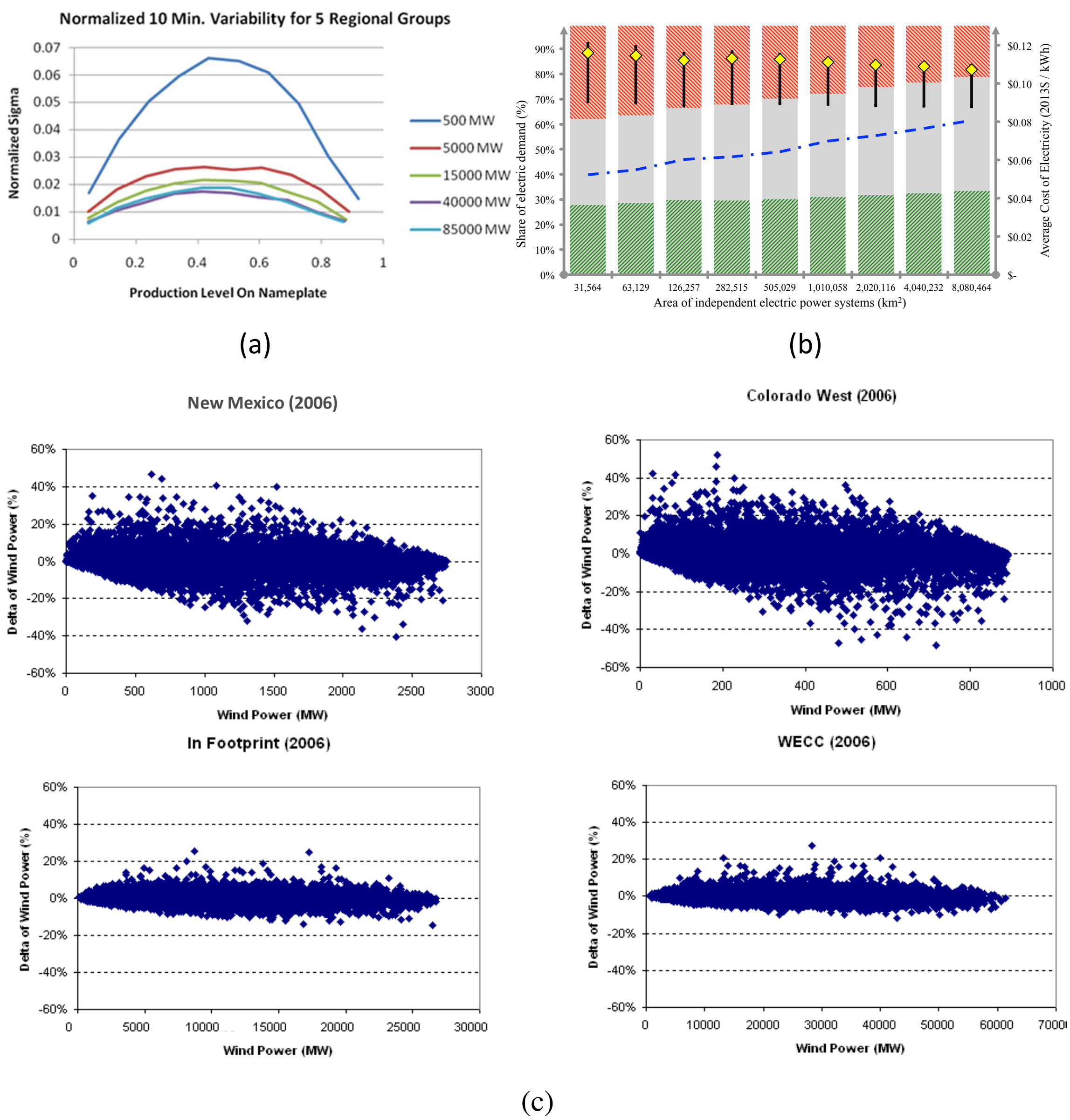


Figure 9: Effects of geographic area on wind and solar variability and cost-optimal integration. (Sources: a & c: NREL, 2012; b: Clack et al. 2015)

demonstrates the impact of geographic scaling (Figure 9b), from small, independent regions (or power systems) to one national system, on energy sources for consumption in an optimized power system. In the plot, green represents renewable generation for a high-cost renewable scenario, while gray represents the additional renewable generation for a low-cost renewable scenario, and red represents all other generation. As the size of the independent systems increase, the cost-optimized electric power grid elects to generate higher proportions of renewable energy generation to meet demand (Clack et al. 2015).

To achieve wide-area integration and coordination and exploit the many benefits, markets and transmission networks must collectively be designed to do so. While market operations facilitate power transactions, it is transmission that is the key, enabling infrastructure that allows efficient market operations to achieve more robust cost savings. In Chapter 2, I will demonstrate the importance of organized electricity markets in context of wide-area operations and renewable energy integration. In Chapter 4, I will explore the key institutional and physical challenges in expanding transmission to provide adequate support of these market operations and access remote renewable resources.

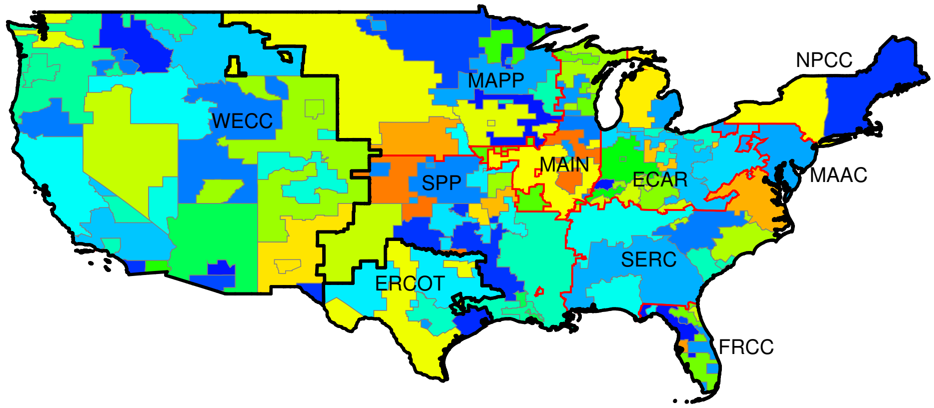
Chapter 2: Electricity Market Expansion and Coordination

The performance of any system involving economic transactions is fundamentally influenced by the operational efficiency and design of the markets that facilitate the transactions. More specifically, the process through which a market links its buyers and sellers can affect how much information is known by the market's participants, thus constraining or enabling optimal decision making and impacting net benefits of the system (Mansur and White, 2012). Furthermore, good market design can reduce the transaction costs involved in getting buyers and sellers together, and can also reduce strategic bidding behaviors that may reduce the efficient performance of the markets. In the following sections, I will describe the evolution of wholesale electricity markets over the past several decades as these markets became more formally organized. This transition establishes precedent for power industry market reform and has (unintentionally) laid better foundations for supporting the integration of variable renewable energy. I will then explore the implications for this evolutionary period, evaluating the two wholesale market systems prevalent in the U.S. – central, organized markets and decentralized, bilateral trading. Finally I will apply these concepts to the integration of variable renewable energy through a case-study analysis of California and the West's EIM transition and consideration of a national power system. These latter cases demonstrate wind and solar integration as an important emerging motivation for grid and market expansion.

2.1: The Evolution of U.S. Wholesale Electricity Markets

The current market structure described in Chapter 1 represents a significant departure from past operations. Prior to the 1990s, when the grid underwent significant regulatory reconstruction, electricity markets and power system operations were dominated by vertically integrated utilities. These entities controlled everything from generating units to transmission and distribution lines, and often functioned as the BAAs themselves. They generally operated in exclusive retail territories as regulated local monopolies. As of 2000, vertically integrated investor-owned utilities generated 80% of all electricity in the U.S. (NREL, 2012). In a drastic transition, however, 60 of the 98 BAAs in 1999 shifted to an organized market structure by 2012, as depicted in Figure 10 (Cicala, 2015).

(a) Approximate PCA Configuration in 1999



(b) PCAs by Market Dispatch in 2012

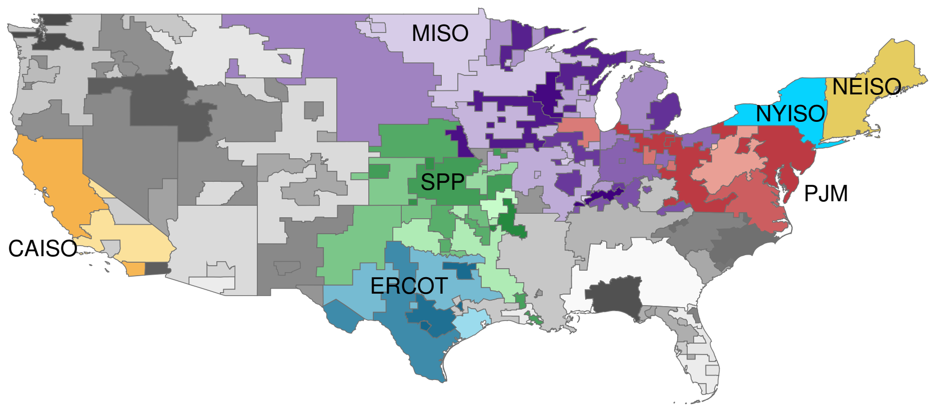


Figure 10: The transformation of control areas between 1999 and 2012. (a) NERC regions are labeled and individual, neighboring balancing areas are distinguished by the different colors. (b) Organized markets (ISOs and RTOs) are labeled and balancing areas are grouped together by similar color shades in each market. (Source: Cicala, 2015).

Over the past nearly half century, FERC and Congress have adopted policies leading to the establishment of more competitive, wholesale electricity markets in the U.S. system. In doing so, these federal organizations have reduced the monopolistic and, more importantly, monopsonistic power of the vertically integrated utilities, which previously were able to deny certain generators access to the grid. Reform first began after the energy crisis in the early 1970s, when Congress passed the Public Utility Regulatory Policies Act (PURPA) of 1978. This legislation required that utilities allow grid access and purchase power from small renewable generators or co-generators, attempting to reduce discrimination against these independent power producers and encourage competition (Sioshansi and Pfaffenberger, 2006; Masters, 2013). In the 1980s, FERC much more firmly introduced wholesale competition by adopting “market-based” wholesale price regulation, which allowed prices to be determined by market competition rather than the previous “cost-of-service”, or “rate-of-return”, regulation.

The Energy Policy Act (EPAct) of 1992 next facilitated the expansion of wholesale power markets by requiring open access to transmission, attempting to lessen the discriminating power that utilities had against any generator. Issues still arose, however, in cases such as when transmission became congested. Utilities could prioritize their own generators and then refuse service to other generators on these accounts. Four years later, FERC Orders 888 and 889 followed up these efforts by helping establish the first regulations governing ISOs to independently manage market operations and allow much greater competition among generators (NREL, 2012). This latter attempt was a more direct effort to encourage an industry structure that facilitated the break up of vertically integrated utilities. By separating their generation and transmission responsibilities, this helped establish more open access, non-discriminatory transmission.

States in the end had authority to decide whether to execute such actions, however, which explains the lack of organized markets in the West and Southeast today. And while power-generating entities were able to access more wholesale, customers with greater equality, issues of remaining “discrimination” were still alleged (Sioshansi and Pfaffenberger, 2006). As a result, in 1999, the FERC issued Order No. 2000, which further encouraged the establishment of independent market operators in form of RTOs. While these entities are essentially the same as ISOs, they were established with a more regional focus and over larger geographic areas. Collectively, these orders helped establish the ISOs and RTOs existing today, although without complete national cooperation, a symbol of resistance that could prove difficult in achieving a national market system described later.

Certainly, wholesale electricity markets have undergone significant transformation and reform to address issues of monopolistic and monopsonistic power and establish more equitable utilization of and access to transmission. As FERC is the primary governing body over wholesale electricity markets and interstate electricity commerce, it can help shape design of organized, wholesale markets and development of more regional based systems. However, while independent market operators now manage power operations in most of the Eastern Interconnection and in California, the remaining transactions are still conducted through bilateral trades and power purchasing agreements. While public utilities in these remaining areas still must abide by the same FERC standards, other types are not regulated[6]. If these areas are to pursue greater regional cooperation, further action by the FERC will be necessary to incentivize such as transition. This will be discussed later in this chapter, particularly in the context of CAISO and the WECC (Western Region), and in Chapter 4, in facilitating regional expansion of transmission.

2.2: Benefits of Electricity Market Organization

Previous research conducted regarding U.S. wholesale electricity markets has primarily focused on either the exercise of market power (vertically integrated utilities, i.e. monopolies), or how organized markets perform in the context of a theoretical, perfect-competition scenario. However, several other studies specifically compared the performances of market organization and decentralized trading, utilizing the changing landscape of the last decade to empirically demonstrate key differences (Mansur and White, 2012; Cicala 2015). These market transitions involved either implementation of a new organized system or expansion of an existing system, and involved the yielding of transmission control to the central ISO or RTO. This organization essentially translates to greater regional coordination, and understanding these implications is important for the future transition of electricity markets in the U.S in support of wind and solar integration.

Cicala (2015) conducted a nationwide analysis of 15 market transitions across the U.S. over the years 1999-2012. Utilizing abrupt shifts from decentralized, bilateral trading to market organization in these cases, he assessed the key benefits from trade and the ability to dispatch the least-cost generation units. Similarly, Mansur and White (2012) assessed the 2004 expansion of the PJM Interconnection (an ISO in the Eastern U.S.) into the

[6] FERC regulates public utilities, which only account for about 2/3 of the U.S, while the remaining 1/3rd are not regulated by the FERC

Midwest, demonstrating significant gains from enhanced transmission utilization. Because market transitions are not randomly assigned through an experimental framework, causal implications can be more difficult to prove. However, due the abruptness of these transitions to market-based dispatch, which occurred in narrow timeframes (often literally overnight), these studies could more reliably draw causal inferences from the time-series before-and-after data.

These papers identify three key benefits from market organization that are related, yet distinct: gains from trade, cost-effective dispatch, and enhanced transmission utilization. First, in many cases, importing electricity for one party is cheaper than using local generation, while exporting power can generate additional net revenue for the supplier. Secondly, lack of market coordination can prevent dispatching the lowest-cost units, resulting in "out of merit" losses compared to the ideal dispatch merit-order. Lastly, transmission networks can become more efficiently utilized, largely due to reduced congestion of specific lines or use of underutilized lines. (Transmission "congestion" occurs when the ideal merit-order of generation dispatch must be altered to avoid causing damage due to too much power flowing on a specific transmission line.) These inefficiencies reflect the consequences of incomplete information and network externalities. Although there might be other routes through which power can be shipped, or alternative, more cost-effective transactions that could occur, inability to coordinate prevents such mutually beneficial trades from occurring.

Cicala first considers an (extremely) idealized national merit order dispatch (i.e. if the entire nation coordinated) compared to operations over the years 1999-2012. He finds that inability to dispatch the lowest cost units across the nation has caused our annual system generation costs to be about double what they could be if all power plants were dispatched at the lowest-cost order (about $72 billion versus $35 billion). Note that this figure only considers generation costs. It does not consider the current feasibility in actually achieving this optimal national dispatch that might be severely compromised by lack of appropriate infrastructure. Nonetheless, it is suggestive of the potential benefits gained by wider-area operations and supportive of a national system. Interestingly, Cicala finds that even though balancing areas were interconnected, 90% of generation was still consumed by the control area itself, which means neighboring controls areas were not utilized. Of course, there are several other reasons why the merit order cannot always be achieved beyond limited networks and small market boundaries: plants are shut down due to maintenance; large plants take time to start up and require fuel, so marginally more expansive plants are used; and large plants continue to operate to avoid these large start up costs (Cicala, 2015). With more dispatch options, however, lower-cost alternatives could likely be utilized. Constrained by institutional boundaries of balancing areas and regional market domains, as well as the inefficiencies of bilateral trade in a significant portion of the U.S., power operators are forced to dispatch more costly units than could be otherwise.

Mansur and White (2012) studied the expansion of the PJM Interconnection into parts of Ohio and Illinois to evaluate the difference between decentralized, bilateral trading and centralized auction markets. In 2004, 19 Midwest firms that had exclusively traded bilaterally joined PJM. The result was stunning: the volume of trade tripled, and by the end of the first year, the system realized benefits over $160 million. Prior to this expansion, the Midwest traded a significant amount of power with PJM but only through a bilateral system. Due to beneficial transactions that became available only in this new market system, a substantial amount of power began to flow from the Midwest to PJM. Almost instantly, power transfer in PJM jumped from around 35 million KWh per day to about 105 million KWh per day, representing an increase in power equivalent to that often consumed by a large city of several million in a day. With the substantial expansion of trade, the wholesale price also fell considerably, by about 10 percent (Mansur and White, 2012).

There are several important points to note here regarding the increase in trade. The only change to the system was the organization of the market. The market system was implemented on a single day; the number of potential total participants (PJM and the Midwest firms) did not increase; and technology and transmission networks remained the same. Interestingly, the increase in trade was not actually due to reduced transmission congestion, but exploitation of underutilized transmission networks. The incorporation of the Midwest firms led to power increases up to the full capacity enabled by the networks. If there had been greater transmission capacity, there could potentially have been greater gains and trade benefits (ignoring the additional transmission costs). In other words, the efficiency gains truly were due to improved allocation of production, replacing production from more expensive units with power from cheaper ones (Mansur and White, 2012). In this case, as the use of transmission lines increased without new infrastructure being built, market expansion actually served as a substitute for transmission expansion.

These results are extremely important in demonstrating the merits of a transition to wide-area market operations. I argue that trading between existing organized markets can be thought of as bilateral trade because there is not a centralized process or entity overseeing and facilitating these transactions. Merging these organized markets can therefore be seen as similar to the process of converting bilateral trade to an organized system: systems expanding or merging to operate over larger regions. Merging existing organized markets could not only bring significant gains from trade and drive us closer to achieving a more efficient national merit-order dispatch, but is also likely to alleviate the need for transmission expansion at the margin, at least to some extent. However, note that this observation does not negate the likely need to develop long-distance transmission to access larger amounts of remote renewable resources, which will be needed regardless as will be discussed in Chapter 4.

The U.S. power industry has evolved significantly over the past few decades, and as more regions have replaced exclusively bilateral trading schemes with the adoption of these competitive, organized markets, many regions have benefited from improved efficiency and the ability to better utilize their available networks and resources. This transition, however, was not driven by the currently emerging need to integrate renewable energy, which played a smaller role in our nation's energy mix. Now, the need for greater renewable energy generation has grown more prominent, and the structure and geographic scope of market networks has become an important part of the discussion. In this next section, I apply the concepts of market organization and coordination to the integration of variable renewable energy through a case study analysis of the California's recent efforts to better integrate with the Western region. This case study not only shows the benefits that the new market system has brought to its participants, but also resistance likely to be shown from certain parties, an important understanding in making this transition across the U.S.

2.3: California and the West: A Case Study

California has ambitious goals in terms of emissions and clean energy. The Governor's Executive Order B-30-15 establishes that California must reduce its GHG emissions by 40 percent below 1990 levels by 2030, and the RPS authorized under SB 32 requires electricity generation to be met by 50% renewable energy the same year (Weisenmiller and Picker, 2015). Researchers have identified over-generation to be one of the greatest challenges in achieving this goal. For example, with 50% solar, it is estimated that over-generation would occur 23% of hours each year, along with severe forecast errors as well (E3, 2014). Various flexibility solutions are in discussion to address this problem, including greater regional coordination and renewable portfolio diversity.

In the 2014 E3 study conducted to explore challenges for California in achieving higher RPSs, each flexibility solution was assessed individually. These include enhanced regional coordination and a more diverse renewable portfolio, described earlier. Compared to the study's business-as-usual scenario, which entailed significant solar deployment to achieve the 50% RPS, the regional integration reduced over-generation from 9% to 3%, with curtailment reduced to 12% annually (Figure 11a). Furthermore, by covering a larger area, the market gains access to greater renewable resource diversity. Because wind and solar are not very correlated, they collectively smooth out the variability and reduce times of over generation, as seen in Figure 11b.

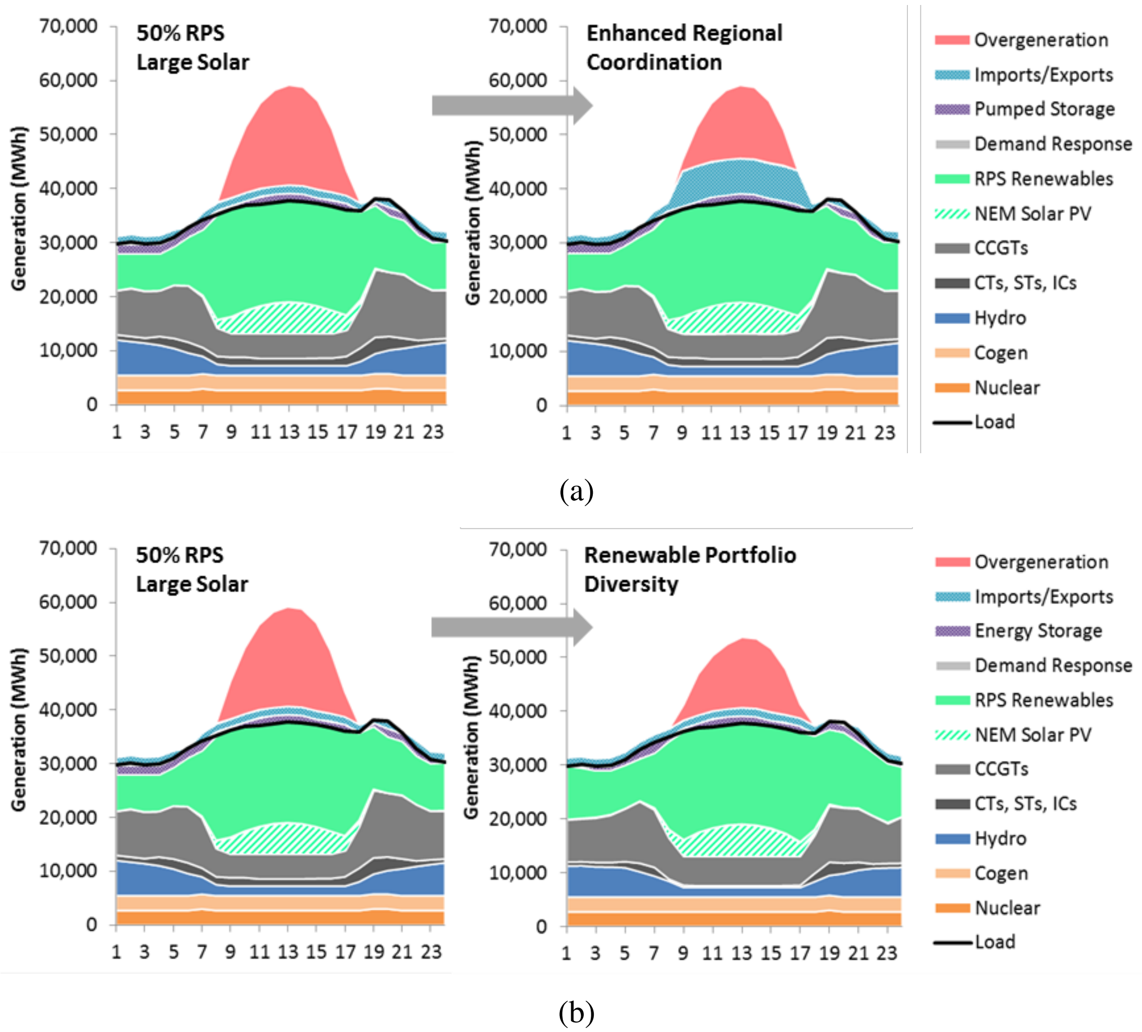


Figure 11: Relevant results from the 2014 E3 Study. (a) Impact of regional coordination: a portion of the over-generation is mitigated through increased trade. (b) Impact of greater renewable energy diversity: total over-generation decreases in this scenario. (Source: E3, 2014)

Largely due to concerns over integration, and with these potential benefits demonstrated, CAISO in November 2014 expanded operations into the Western region, merging with PacifiCorp, a major power utility operating in six Western states (CAISO, 2014). Forming the Energy Imbalance Market, this regional, FERC-approved initiative is a crucial step towards greater regional market coordination and supports reliable, renewable energy integration in the region at lower costs. It is also an important case study and example for other regions, especially the Southeast which similarly does not maintain an organized market. The two largest power entities in the Western region, collectively serving about 32 million customers, now coordinate on real-time electricity

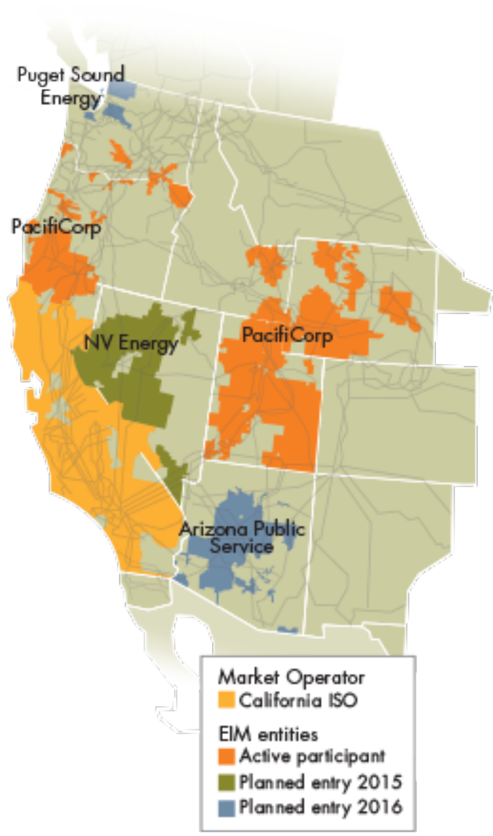


Figure 12: CAISO and EIM participants in the WECC (current and potential). (Source: CAISO, 2014)

transactions, which typically take place within 15-to-5 minutes of dispatch. While 38 balancing authorities have traditionally governed power operations in the region through manual dispatches and relying on reserve capacity to ensure reliability, the ISO market system automatically dispatches the most economical sources every five minutes to match the constantly varying demand. As a result of the increased coordination through the EIM, the balancing authorities are now better equipped to handle short-term fluctuations in supply and demand (CAISO, 2014).

The conceived benefits of regional coordination appealing both parties in the EIM included reduced costs, improved reliability, and lower-cost emission reductions, all while achieving higher levels of renewable generation. Collectively, these gains could potentially save between $3.4 billion and $9.1 billion over the next twenty years (E3, 2015). By sharing power and resources over a larger region, CAISO and PacifiCorp believed existing high-voltage transmission networks would be more efficiently utilized to balance supply and demand, especially with renewable generation. Because the market allows for generation changes minutes before dispatch, variable solar and wind can be much more confidently deployed. Excess solar generation in California can benefit the West, especially because peak demand for many states in the West is actually a few hours earlier than in California (when California might be generating high volumes of solar). This transfer of solar energy would reduce California's curtailment while allowing the West to cheaply offset costly and dirty fossil-fuel generation. California can also benefit greatly from greater integration with the West, especially in terms of greater access to wind generation in the Midwest and Great Plains regions, which have the greatest production during California's peak hours, as well as hydropower generated by PacifiCorp that can improve flexibility in California's supply. Lastly, the larger region can bring additional benefits in terms of sharing reserves, a source of significant costs that would accompany greater variable renewable energy generation otherwise (PacifiCorp, 2014).

The EIM has already been a success. During the first eight months of market operation, the system saved $21 million (CAISO, 2014). In Quarter 1 of 2015 for example, CAISO estimates a total benefit of $5.26 million, including $74,000 saved from reduced flexibility reserves among the BAAs, and 8,860 MWh avoided renewable energy curtailment (CAISO, 2015). There have also been significant power transfers, particularly from PacifiCorp to CAISO. As a result, the power companies are now exploring a further expansion of the partnership, which would entail full integration of the day-ahead market and full coordination of operation and planning. This would also involve PacifiCorp yielding full transmission planning and operation of the network to CAISO. There are concerns, however, especially from California in connecting with states that have high percentages of fossil-fuel generation, such as Wyoming. Because electrons are uncontrollable, electrons generated from dirty energy sources could possibly flow into California and compromise its emission reducing initiatives. Wyoming is similarly resistant to foregoing coal production and generation, one of the state's most important industries (Morain, 2015). These concerns highlight why some states would oppose expansion even if it could bring net benefits. While PacifiCorp generates 58% of its electricity with coal, it is already planning to retire 14 coal plants in compliance with the Clean Power Plan. PacifiCorp and CAISO also maintain that costs imposed by California's cap-and-trade program would prevent coal-generated electricity from reaching California regardless (Morain, 2015). If the EIM assessment study currently underway encourages full partnership, stakeholder approval would be necessary and regional governance would need to be addressed.

In addition to further partnership between California and PacifiCorp, several other utilities are also expected to join the EIM due to its demonstrated success. In fact, NV Energy from Las-Vegas has official entered and begun participating as of December 1,

2015. NV Energy anticipates benefits of around \$6 - \$10 million per year by 2017, and \$12 million per year by 2022 (CAISO and NV Energy, 2015). Puget Sound Energy (Washington State) and Arizona Public Service are expected to join in Fall 2016 (Figure 12), and Portland General Electric and Idaho Power Company are considering participation as well (E3, 2015). If the entire West can achieve regional coordination, benefits will be substantial, as demonstrated by a 2013 study conducted by NREL. This study assesses benefits for the entire Western region in terms of flexibility reserves (specifically for wind and solar variability) and production-cost benefits for the over-all system performance. These are both considered in context of integration throughout the region as well as adopting the faster market dispatch system. By incorporating the entire Western region in the EIM, the study finds that savings could range from \$146 million to \$294 million in terms of reduced flexibility reserves, and \$1.3 billion for the implementation of the faster 10-minute dispatch (NREL, 2013). The appeal shown by future participating parties and their likelihood in joining is encouraging.

The initiatives taking place in the Western Region represent a new transitional period for the U.S. While the restructuring in the 1990s and early 2000s also saw significant market reform to adopt organized markets, this new period is unique in that a large motive in adapting these systems now is to accommodate higher levels of renewable energy. The EIM not only represents the expansion of an organized market, which has occurred in many regions across the U.S., but demonstrates the merits of wide-area coordination in combating variable energy integration challenges.

Visions of expansions and larger markets have been considered in the past, even if not in consideration of renewable energy integration. For example, most likely in response to FERC Order 2000, which encouraged development of RTOs, Edison Electric Institute produced a map (Figure 13) in 2001 of a nation-wide expansion of organized market operations to 5 major RTOs. While this vision was never seen to fruition, it does demonstrate ideas of expansion on this larger scale. Additionally, Cicala's study discussed earlier suggests merits of a national market that can take advantage of a national merit-order dispatch. The study considers systems for within balancing areas, within NERC regions, within Interconnections, and across interconnections (a national system), and finds that allowing efficient trade across larger geographic areas further improves allocation (Cicala, 2015). The idea of further expansions of regional markets would not be a new concept, and a powerful, new motive of renewable energy integration provides ample justification.

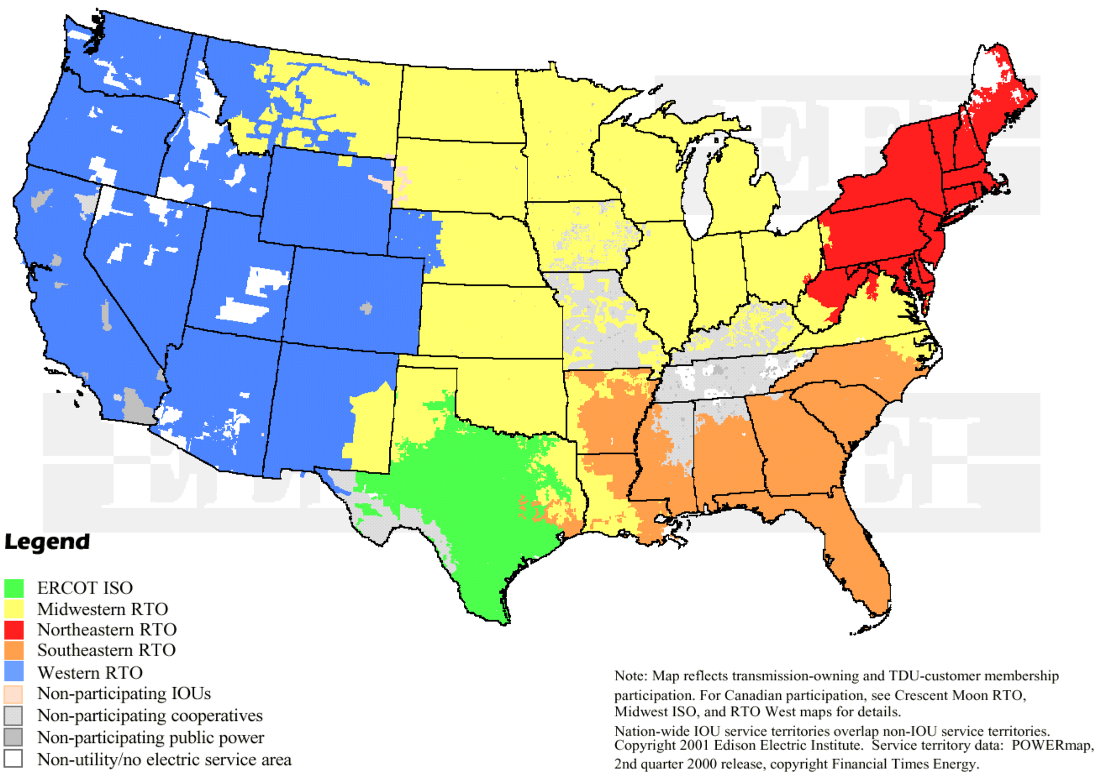


Figure 13: A vision of 5 RTO's nation-wide, created by the Edison Electric Institute (EEI, 2001).

2.4: Considering A National System

While initiatives such as the EIM demonstrate contemporary endeavors to integrate renewable energy, system operators must also consider large-scale reform in the coming decades. Numerous studies assessing the impact of higher levels of penetration of wind and solar power have determined that significant changes will need to occur to the power system, particularly in terms of transmission infrastructure and greater interconnection across wider areas, at least to some extent. While the Eastern Interconnection conducts by far the most power transactions (73%), the West and Central U.S. are where some of the best wind and solar resources are located. Linking wider areas across the U.S. could therefore better align generation capability and load demands (McCalley and Krishnan, 2014). This reform could involve greater consolidation of balancing areas over wider areas, or possibly greater connection between the three interconnections. An interesting part of this discussion has also included the implementation of a national network – a so-called "super highway" or overlay system. This system would operate in conjunction to existing regional infrastructure and connect the entire U.S. with high capacity and efficient lines for the transport of the energy across the nation. In essence, this system would enable a national market for electricity. Rather than HVAC lines as most transmission is in the U.S., this system would use HVDC lines, which can sustain 2 to 5 times more capacity than an AC line for a given voltage, have lower transmission losses over longer distances, and allow more control in shipping power from point-to-point (Reed, 2011; MIT, 2011). Despite significant institutional and physical challenges in developing such a system, numerous studies have hinted to the benefits it would bring.

In 2008, the DOE conducted a study to explore the implications of achieving 20% wind power by 2030. Its researchers determined that significant levels of transmission expansion would be necessary in order to reach these levels. The WinDS model, or Wind Deployment System, finds it cost-effective to build 12,000 more miles of new transmission costing $20 billion. While generation in the more immediate future could use existing capacity, these additional lines will become especially important in the longer term. Interestingly, the study also suggests that a national "super highway" could be very beneficial in accessing remote resources and shipping them to load centers across the U.S. The study showcases a conceptual overlay system of 765 kV transmission lines (Figure 14) devised by American Electric Power to enable this 20% goal, costing $60 billion for the 19,000 miles of lines (DOE, 2008).

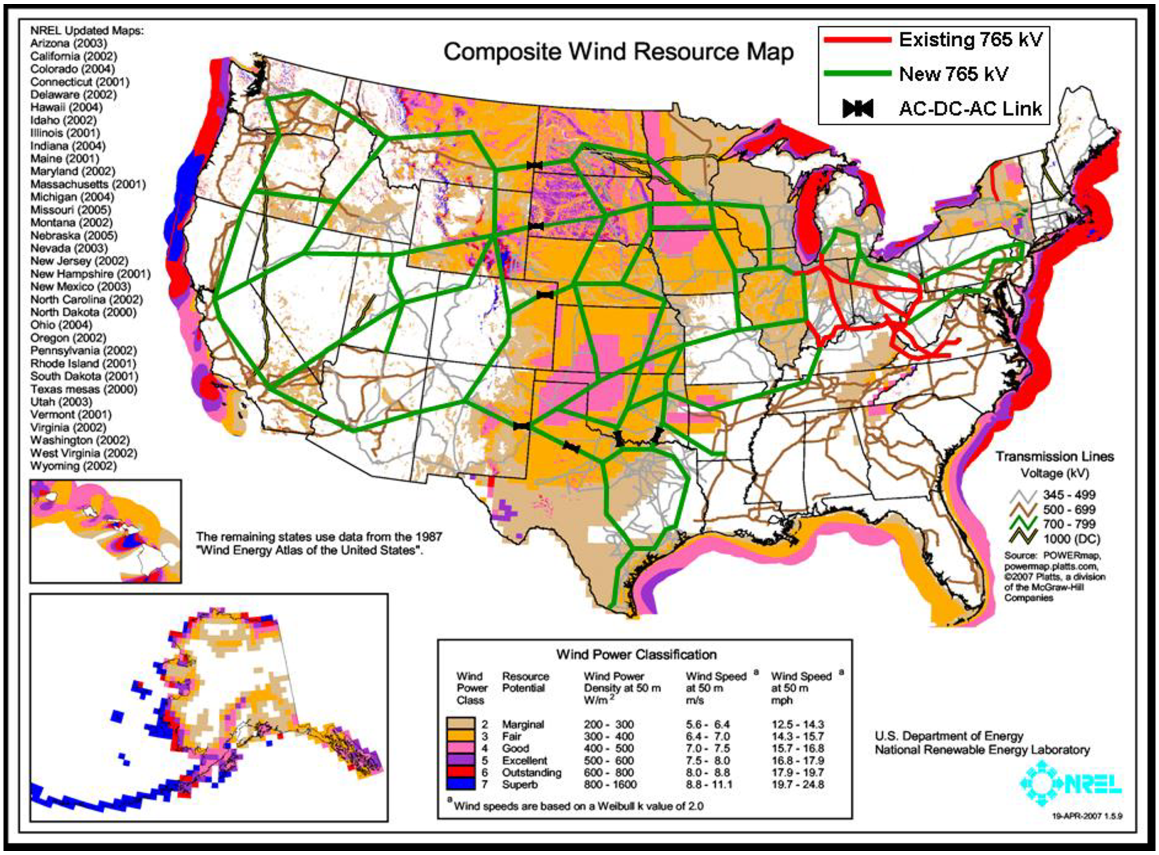


Figure 14: A conceptual high voltage transmission network designed by American Electric Power. (Source: McCalley and Krishnan, 2014)

In 2012, NREL conducted a Renewable Electricity Futures Study to assess implications of high penetration renewable energy. In this study, they modeled various scenarios requiring different levels of renewable energy utilization in the U.S. system, from 30% to 90%. Of these percentages, the study specifically required significant portions from wind and solar photovoltaic (PV) generation. With higher penetrations of renewable energy, the model elects to build greater connections between the three interconnections, enabling more of a national power system (NREL, 2012). While this study does not specifically consider an overlaid national network, the results suggest the need for and benefits of connections on a more national level and across interconnections.

Most recently, researchers at NOAA have devised a model of the power system – the National Energy with Weather System (NEWS) Simulator — to explore the impact of a national system. The conceptual overlay of this network was shown back in the

Introduction (Figure 2). While most transmission lines in the U.S. are HVAC, this model implements a national HVDC network. Strikingly, this system in the model enables reductions in CO_2 emissions of up to 80% of 1990 levels by 2030 – with existing technology and without increases in average electricity costs (Clack et al., 2015). These results, which are displayed in Figure 15, are largely due to ability to better integrate wind and solar power.

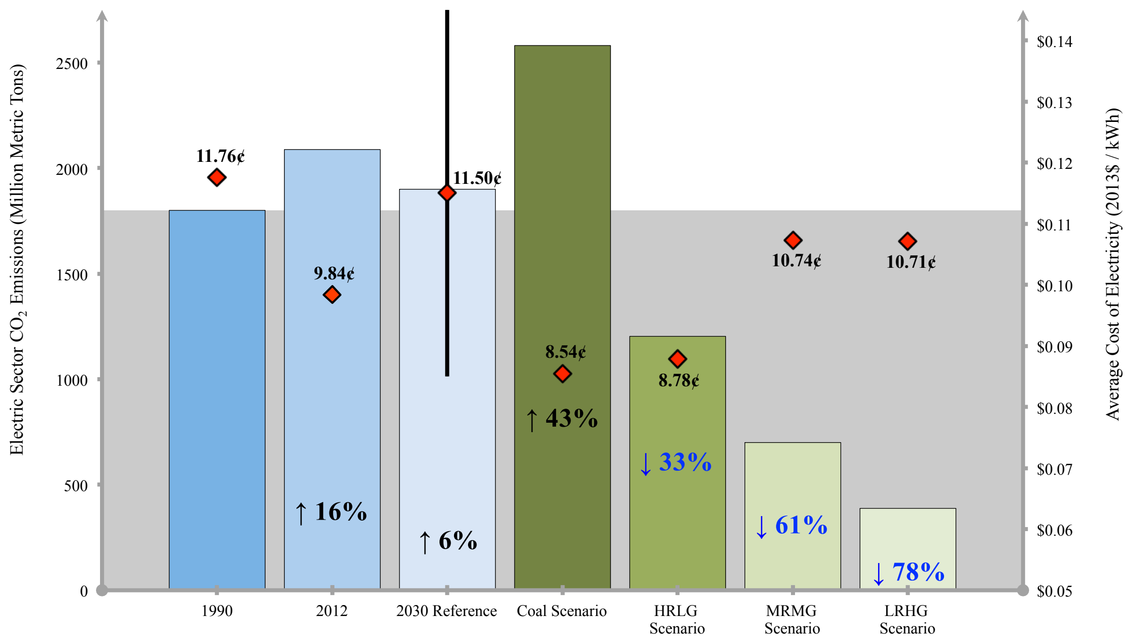


Figure 15: NEWS model CO_2 emission reductions and costs for 2030 with the national HVDC transmission network. (Source: Clack et al. 2015)

All of these major studies have been conducted by federal U.S. research agencies, giving the proposals significant legitimacy. According to the MIT Future of the Electric Grid report in 2011, "interregional renewables integration studies, such as the Eastern Wind and Integration Transmission Study and the Western Wind and Solar Integration Study have shown that integrating high penetrations of renewables in technically feasible through higher-voltage, tightly meshed transmission lines, but a true plan has yet to emerge" (MIT, 2011). The NOAA study begins to address this void with a conceptual plan and demonstrates the implications for full U.S. market expansion and integration and the development of transmission – what could hypothetically be achieved with maximum utilization of resources.

The merits of wide-area market organization and coordination as demonstrated to the extent thus far are certainly substantial, facilitating more cost-effective dispatch in better alignment with the merit-order, reducing the net variability of wind and solar resources, and reducing congestion while improving transmission utilization, among other benefits. In the next chapter, I will complement this discussion by presenting modeling results that specifically further NOAA's research of a national system using the NEWS model. This research highlights various scenarios of expansion on regional and national levels to explore the extent to which expansion is necessary and most beneficial. In other words, are there substantial benefits from constructing a national network compared to expanding and strengthening the existing regional systems? These results are the product of research I conducted at NOAA's Earth System Research Laboratory (ESRL), where the NEWS model was developed. They also reflect contributions from a whole team of research scientists at ESRL, but in particular my mentor Dr. Christopher Clack, who has been the primary developer of the NEWS model.

Chapter 3: Modeling U.S. Power System Reform for 2030

A number of prominent models exist to simulate the U.S. power system. The EIA uses its National Energy Modeling System (NEMS) model to produce an annual report called the Annual Energy Outlook. This report considers the current status of the power system and estimates what the system might look like under various scenarios over the next 30 years or so. Similarly, the NREL deploys many models, but of particular relevance is their Renewable Energy Deployment System model (previously the Wind Deployment System model used in the 20% wind study discussed earlier). Another prominent model used for more direct policy research is Resources for the Future's Haiku model, which actually conforms to the NEMS model output. While all these models differ by how they simulate the power system, they are the basis of influential studies and research that shape policy, reform proposals, and investment in the power industry.

NOAA has over the past several years also developed an optimization model for the U.S. electric power system called the National Energy with Weather System (NEWS) Simulator. This model was built for the specific purpose of assessing the feasibility of integrating high volumes of wind and solar PV into the electric grid with the implementation of a national HVDC transmission network. In doing so, the model is able to determine the cost-optimal blend of power generation and locations across the contiguous United States for the year 2030, as well as lay out various features of the system such as generation and capacity for each source, installed transmission, CO_2 emissions, and electricity costs. While working at the NOAA Earth System Research Laboratory in Boulder, CO, we modeled three system scenarios that reflected (1) current electricity markets; (2) regional market expansion from the current markets; and (3) a national system connected by a national HVDC transmission network (slightly altered from the previous NEWS studies). Transmission within each region is also constructed within the model to provide adequate capacity at the lowest cost, ensuring market regions are properly integrated with transmission. With the tools developed in this research, I am able (1) to assess the marginal benefits of expanding markets and transmission on a regional level versus implementing a national HVDC transmission network, compared to regions that reflect existing market sizes and transmission networks; and (2) to provide suggestive conclusions from a national perspective regarding the extent of reform that must occur over the next decades to best facilitate the achievement of a clean electricity future.

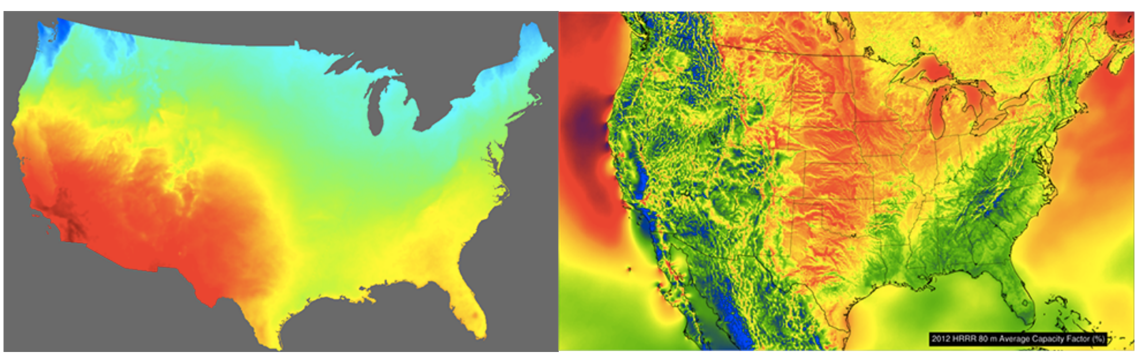
The question regarding electricity market reform here must first be clarified. As the model determines a cost-optimal solution for each "independent" region, it inherently assumes a reasonably efficient market operator in that region, functionally achieving the results that one would expect from an ISO or RTO operator, i.e. an organized wholesale market. Thus, the model demonstrates the implications of expanding and merging these organized markets themselves, rather than assessing the merits of transitioning the remaining West and Southeast regions from bilateral trading schemes to market organization. Few studies, if any, have examined the merits of expanding existing organized market themselves as is done here.

The purpose of this thesis is not to predict whether a national-level transmission system will be implemented, as there are considerable institutional and technical challenges in executing such a large-scale project. Instead, its purpose is to demonstrate the likely implications for wide-area integration at the highest level, specifically what an optimized electric power system utilizing a national market and national transmission network could look like compared to a less intensive regional expansion scenario. By modeling for the year 2030, the model can assess major reform that could potentially take place over the coming 15 years.

The following section provides relevant descriptions of the NEWS model for this study, before any further modeling was conducted to create the new scenarios and results presented in this paper. These model descriptions primarily source from Clack et al. (2015), which contains the NEWS model documentation. (For more detailed documentation on the NEWS model framework and study applications than presented in this Chapter, see Appendix A, or Clack et al. (2015) for full documentation.) Following this model description, I will then explain expansions to the model that allowed the various scenarios explored in this new study, and then present results.

3.1: The National Energy with Weather System Simulator

The NEWS model is highly robust and unique in two aspects. First, it incorporates NOAA's high-spatial (13-km) and -temporal (60-min) resolution weather data for wind and solar resources (wind speeds and solar irradiance) in the continental U.S over the years 2006-2008. This data is then modeled to produce power capacity factors (Figure 19) for wind turbines and solar photovoltaic (PV) panels at each of the ~150,000 model grid locations. To complement this dataset, the model also integrates concurrent hourly electric load for the years 2006-2008, which is then scaled to 2030 using projected economic growth. This load is available for up to 256 regions throughout the U.S., and crucially must be matched by generation at each hour in the simulation to ensure reliable power supply. This is the first model to achieve this high resolution, spatially and temporally, with the integration of weather data to calculate wind and solar potentials. Utilizing NOAA's weather expertise, the NEWS Simulator has proved to be an extremely well suited tool in exploring the integration of weather-driven renewable energy. Secondly, and certainly its most differentiating feature, the NEWS Simulator was originally built with a national network of HVDC transmission, which has been detailed earlier.



(a) (b)

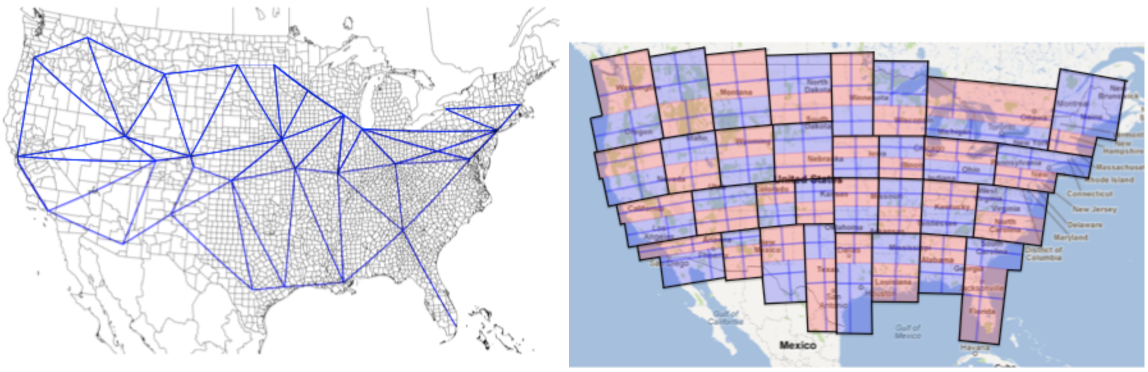
Figure 16: The average solar PV power (a) and average wind power at 80 meters (b), created from the power capacity datasets used in the NEWS model. The solar power data is for the years 2006 – 2008 from NOAA's Rapid Update Cycle model, while the wind power data is for 2012 from NOAA's High-Resolution Rapid Refresh model. (Source: Clack et al. 2015)

The NEWS model simulation considers a variety of parameters, both exogenous (user supplied) and endogenous (within the model), in solving for the cost-optimal solution. Inputs provided by the user include costs of generation (e.g. capital costs and fuel costs), costs and loss percentages per mile for transmission (HVDC and HVAC), weather and power capacity data, an hourly electrical load that must be met at all times, generation siting constraints (where power plants can be built), geographic boundaries, and transmission node locations (load centers). Power plant constraints such as ramping limitations, minimum turndown levels, and reserve requirements are also provided. The model then considers these inputs and constraints and uses linear multivariate regression techniques to determine the cheapest yearly solution. In doing so, it decides which technologies should be built where and how much power should generated, as well as how much power should be shipped via transmission and how far. Transmission within each region is also constructed within the model to provide adequate capacity at the lowest-cost, ensuring market regions are properly integrated with transmission. Lastly, the model also outputs characteristics of this optimal system such as CO_2 emissions, electricity costs, generation and capacity of each technology, and capacity of transmission lines.

Divisions, Nodes, and Transmission:

The model is designed to consider various scales of divisions, or systems, within the U.S. These divisions are determined by boundary input files into the model, which facilitate the assignment of model grid points to the corresponding area. In the previous NEWS model, the scale of divisions ranged from one national system to a system comprised of 256 independent regions, each made by repeatedly dividing land area in half, vertically and horizontally. For systems with 32 or fewer divisions, the model maintained 32 nodes throughout the contiguous U.S. with adjacent nodes connected by a national HVDC transmission network, as displayed in Figure17a. Each node lies within a nodal area, or regional market area, each of which is further comprised of eight smaller regions connected by HVAC transmission (note: 32 nodal areas with eight divisions each constitutes the 256 areas). Considering a system with more than 32 independent regions, these regional market areas become irrelevant and only HVAC transmission is available.

Figure17b depicts the 32 nodal areas. To conduct the present research, however, I converted the NEWS model divisions to reflect state political boundaries and electricity market regions, which will be demonstrated later.



(a) (b)

Figure 17: The previous national HVDC transmission network (a) and nodal areas/market regions (b) modeled in NEWS. The 32 nodes are located in geographically diverse regions created by repeatedly dividing U.S. land area vertically and horizontally, and are sited near major population hubs. (Source: Clack et al. 2015)

Generation Technology and Siting Constraints:

The model simulates all major types of generation, including coal and nuclear-fired power plants, natural gas combined cycle power plants, onshore and offshore wind, solar photovoltaics (PV), geothermal, and hydroelectric. The model considers the current state of the power system in 2012, as depicted in Figure 18, and then determines the cost-optimal additions and alterations to this existing state to form the optimized system for 2030. Importantly, nuclear and hydroelectric capacities are fixed at these 2012 levels, with facilities placed where they existed at that time, while any fossil-fuel power plant *can* (but is not required to) be built where there was an existing plant. This is because the model projects a significant period of time into the future, and there are estimated to be substantial early retirements of coal generation in the next decade or so, particularly in light of recent EPA regulation (Clean Power Plan) and the explosive rise of the availability of natural gas (MIT, 2011). Furthermore, the siting of new renewable projects is prevented in urban or protected areas, or where land characters are unfavorable (e.g. steep slopes).

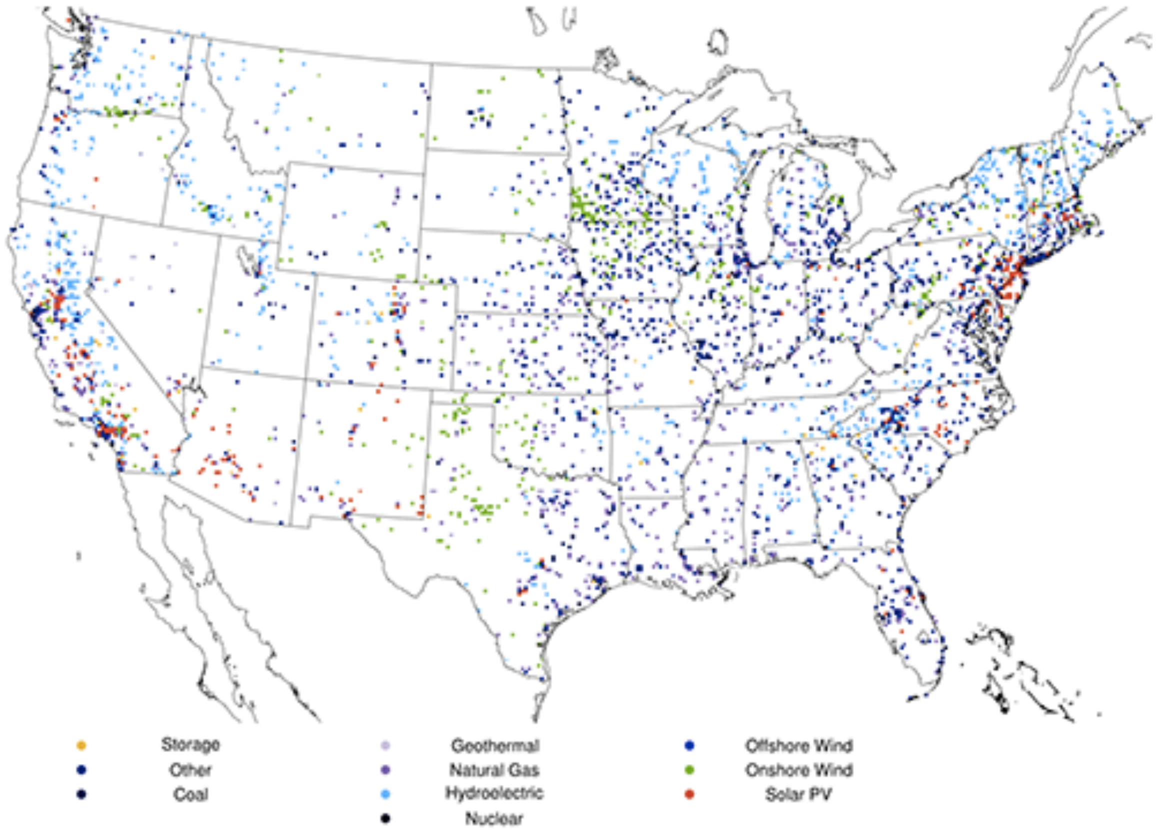


Figure 18: Generation siting by source across the electric power system in 2012, assumed as the initial condition in the NEWS model. (Source: Clack et al. 2015)

3.2: NEWS Model Expansions and Modeling Scenarios

This present study involves several expansions to the NEWS simulator capabilities and modeled structure in efforts to assess the merits of system expansion on the regional versus national level. For example, to reflect current political divisions and conduct state-level analysis, it was necessary to incorporate state boundaries into the model. This involved assigning model grid points to states, as well as transferring existing regional components to those boundaries, including hourly load data, potential generation sites for wind, solar and conventional sources, and nuclear and hydro generation.

This section highlights the key expansions made in the NEWS model that enabled the various modeling scenarios. First, we incorporate existing federal and state policies for renewable energy into the simulator. Previous studies using the NEWS model have sought to determine the optimal solution without regard to current regulation (Clack et al.

2015). The major policies incorporated here include the PTC and ITC at the federal level and RPSs at the state level. These policies are assumed to persist through 2030 (the model's target year). Secondly, this study models several new boundary types: (1) state boundaries to reflect political divisions and enable application of policy and state-level analysis (e.g. regulation and generation); and (2) two levels of electricity market regions that more accurately resemble the size of today's markets and a potential expansion scenario. These new boundaries reflect a departure from NEWS model's previous divisions of the United States, which had been invaluable in assessing system sensitivity to geographic scaling (shown back in Chapter 1, Figure 9) in Clack et al (2015). Importantly, these new boundaries accurately reflect how location-dependent renewable resources would be utilized given U.S. institutional boundaries, which could be different in comparison to the previous boundaries assessed in the geographic scaling study. Lastly, a new national network is established using the state-level capability to place nodes strategically in each state in consideration of political siting constraints of transmission. These contributions aim to further increase the robustness of the NEWS model, and to enable the most accurate representation of the U.S. electric power system necessary for pertinent investigation of solutions in supporting high-penetration variable renewable energy. (For more detailed description of the modeling methodology behind these expansions than is described in this Chapter, see Appendix A.)

U.S. Electric Sector Policies:

The policies modeled and incorporated into the NEWS modeling suite are described here. Descriptions of the mathematical modeling behind these policies are available in Appendix A.3.

Figure 19 displays the existing state RPSs as of June 2015 and the values used in this study. California has since increased its RPS to 50% by 2030, but this change occurred after the simulations were completed. Eight states have renewable portfolio "goals", but these are not modeled in NEWS as they are not mandated requirements. Here, the RPS is modeled as a load constraint: the yearly renewable energy generation must be at least as large as the RPS fraction of the electrical load in each state.

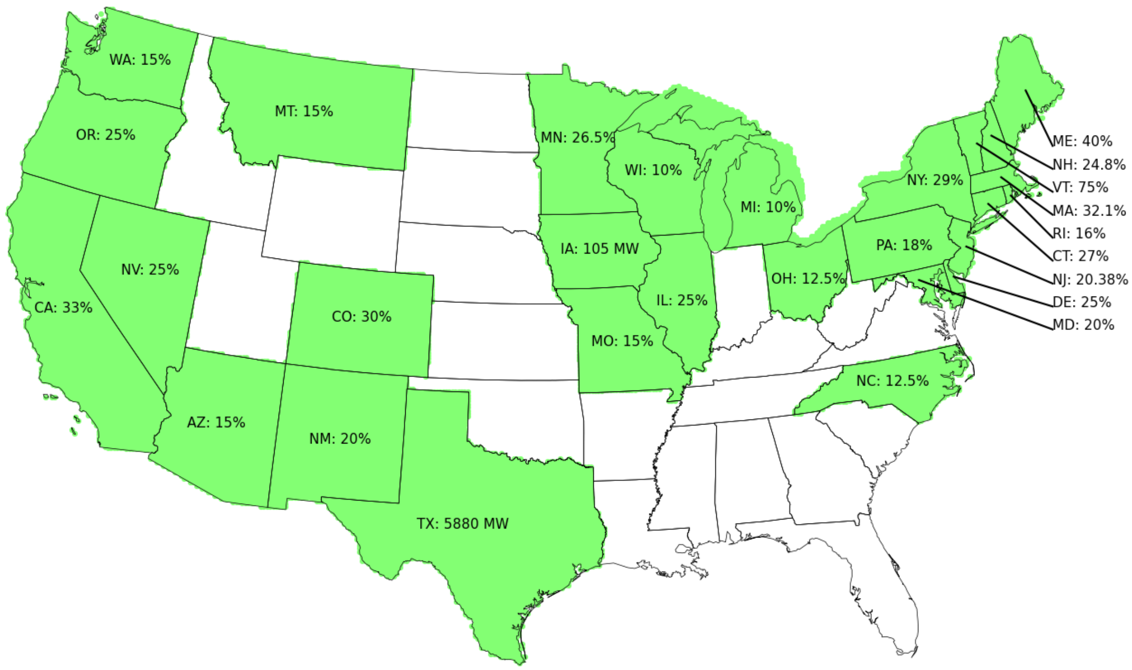


Figure 19: The state renewable portfolio standards modeled in NEWS. These represent current state legislation as of June 2015. No state goals (non-mandatory) are included.

Next, the federal renewable energy incentives (PTC and ITC) were modeled. The PTC is a federal-level corporate tax credit, acting as a per-kilowatt-hour production subsidy. Specifically, it awards wind technologies $.023 for each kWh of generation for the first 10 years of operation. Similar to the PTC, the ITC is also a federal-level corporate tax credit. However, rather than incentivizing production, this incentive supports investment of various renewable technologies. Of interest in the NEWS model, the ITC awards a 30% tax break for solar investments. Rather than modeled as a constraint like with the RPS, these values, as described in Appendix A.3, are input into the model's cost function, which is then minimized to determine the cost-optimal solution of the power system.

Incentive	Value	Qualifying Technology
Production Tax Credit	$23 / MWh	Wind
Investment Tax Credit	30%	Utility-PV

Table 1: Federal Renewable Energy Incentives in NEWS

National and Regional Systems:

The first change to the power system structure modeled in the NEWS Simulator is a new national HVDC network connecting adjacent states with a node, or load center, in each state. The state-oriented nodes do not necessarily represent optimal siting locations given the geographical layout of resources in the U.S., but are designed in such a way as to be appealing to states and Congress. By providing each state its own hub, and by requiring power to be shipped between adjacent states, the model respects political institutions and prevents power being shipped entirely through state areas without gain for that state. The location of each node was determined by the population-weighted center of the top five most populous cities, ensuring that the majority of power would be within reach of the largest demand. This national system is depicted in Figure 20.

I then modeled boundaries of two regional systems consisting of regional electricity markets based on the NERC regions and sub-regions, respectively (Figure 24). The 20 sub-regions are based on boundaries used in EIA's NEMS model, RFF's Haiku Model, and the EPA's eGrid Model, which are intended to reflect current regional market structures[7]. Given these sub-regions, the natural regional expansion was then to the 8 NERC regions. In modeling these boundaries, each region is approximated by aggregating the states most closely matching the actual boundaries. Transmission networks comprised of HVAC lines connect adjacent state nodes in each region.

As a result of these boundary changes are three system scenarios: (1) "sub-NERC", with regions representing current markets; (2) "NERC", with regions representing region expansion; and (3) a "National System" with HVDC transmission.

[7] The FERC electricity regions might arguably better represent how power is shared today and could be incorporated in future studies.

Figure 20: The new national HVDC transmission network with 48 state nodes. Each node is located at the population-weighted center point for the state's top five most populous cities.

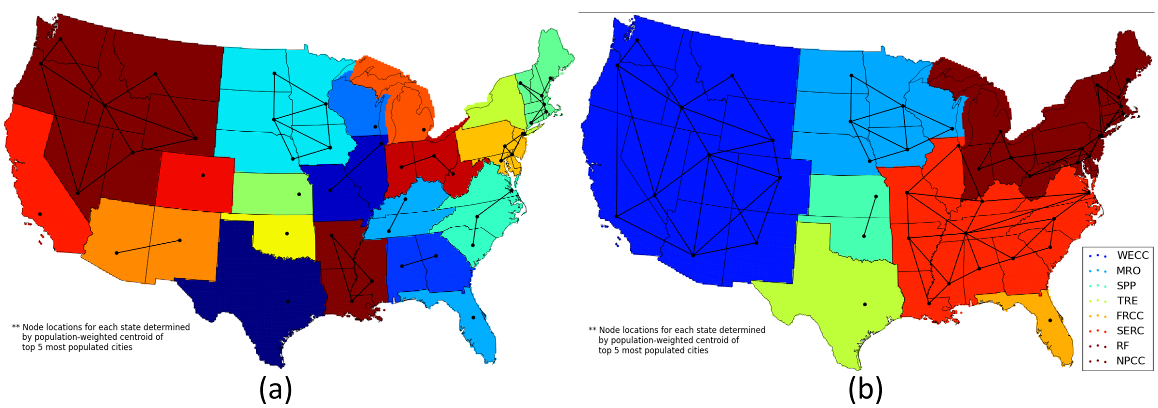


Figure 21: The twenty subregions representing current markets (a); and the eight NERC Regions representing regional expansion (b). Both systems use HVAC transmission.

3.3: An Optimized Power System in 2030

To assess the merits of system expansion on a regional versus national level, each of the three systems were simulated with a variety of policy scenarios. For each system, we applied the state RPSs and federal renewable energy incentives separately to see the individual impact and also because the future of the PTC and ITC policies are unknown[8]. We also simulate a “No Policy” scenario representing market competition alone. I first evaluate the system outcomes on a national level through six metrics: renewable energy deployment, CO_2 emissions, electricity costs, wind and solar PV capacity, and policy effectiveness. I then explore the systems in more detail and present state-level analyses.

Figure 22 shows a national-level summary of each system and policy scenario in terms of the six criteria. This allows for analysis in terms of both regional and national expansions from the sub-NERC regions under the various policy scenarios. The trends seen in the impact of expansion in all scenarios supports the findings in the previous geographic scaling study using the NEWS model – as the sizes of the “isolated” systems increase, the cost-optimal electric power system solution achieves higher levels of carbon-free generation (namely from wind and solar PV), lower electricity costs, and reduced carbon emissions. The relationship with geographic scale was an expected result, however. The real question at hand is how each system compares on the margin – i.e., by what extend do the two expansion scenarios actually differ. In other words, are there substantial benefits from constructing a national network compared to expanding and strengthening the existing regional systems?

The results suggest that the national system outperforms the NERC regional system by a substantial amount in all policy scenarios. The marginal benefits of both expansion scenarios compared to the sub-NERC scenario are highlighted in Figure 22 by the labels above each bar. Considering the PTC/ITC policy scenario, for example, carbon-free generation increases by 15.3% in the national system compared to 4.8% in the NERC system. As nuclear and hydroelectric are fixed, these increases are due to solar and wind alone. Additionally, CO_2 emissions decrease by over 33% in the national system compared to about 10%, and both wind and solar PV capacities increase by over three times amount in the NERC scenario. Costs are likewise lower in the national scenario, despite more transmission investments, due to the utilization of lower cost wind and solar

[8] Due to computational and temporal constraints, combined policy scenarios were not simulated. This is a possible consideration for future work.

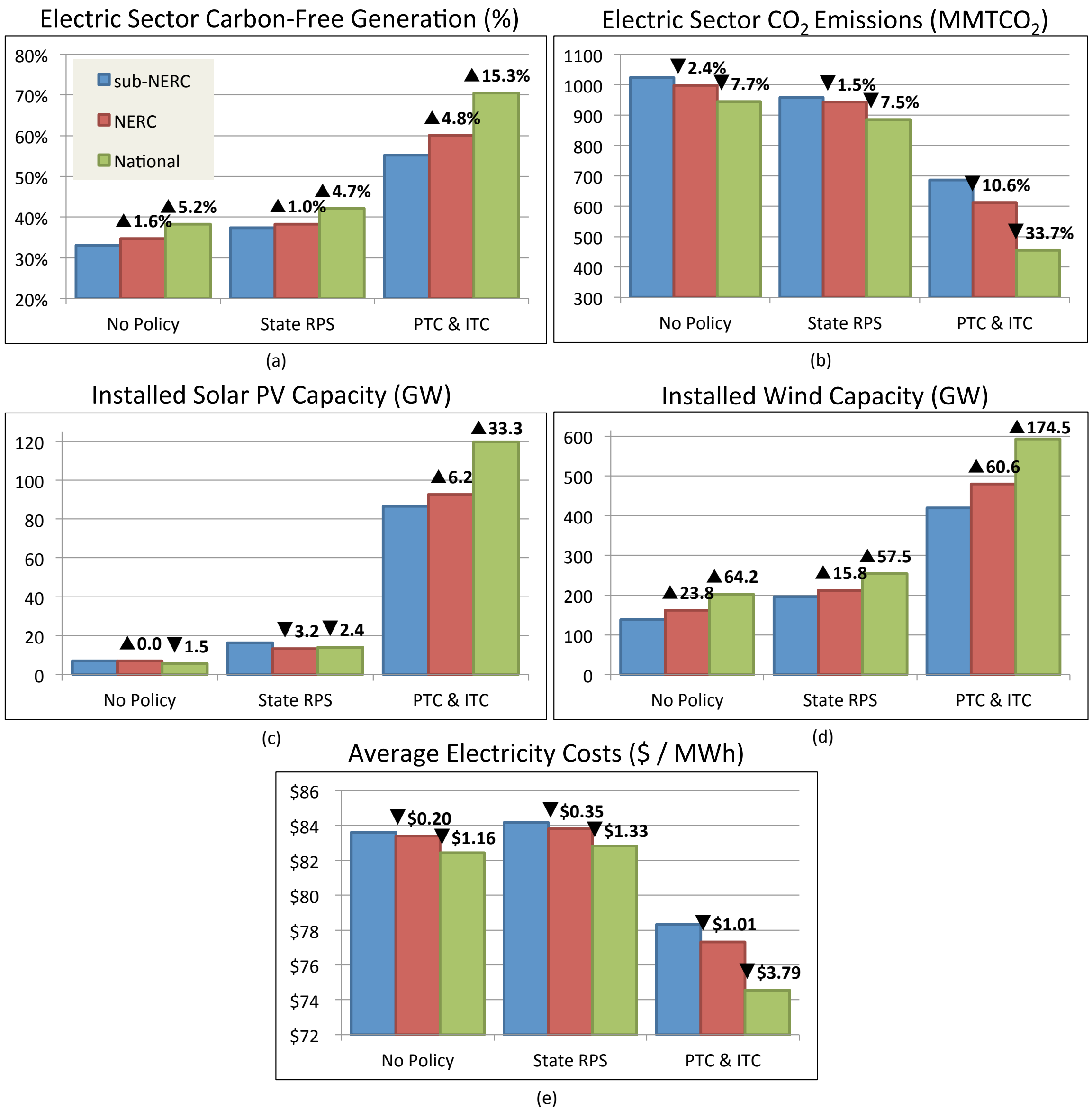


Figure 22: Key characteristics of the U.S. Power System for each system and policy scenario. The data labels represent change from the sub-NERC scenario, i.e. the marginal impact for regional expansion and the implementation of a national HVDC transmission system.

generation. In assessing the impact of each system expansion, it is clear that the policy scenario does make a difference (although the trends remain the same). Certainly, the PTC & ITC scenario shows higher levels of renewables, lower emissions, and lower costs than the RPS or No Policy scenarios in each respective system. While the purpose of the study is to compare the impact of each system rather than policy, it is interesting to note that the PTC & ITC scenario appears to enhance the benefits of system expansion on the margin. In other words, system expansion is most beneficial with these policies in place.

It is also important to consider the amount of curtailment and losses in each system. Curtailment refers to the amount of renewable energy generated but not used to meet load, while losses refers to the loss of electricity during transmission. In all policy scenarios, losses tend to increase with the geographic scale, which makes sense as more transmission is built. However, the losses are rather small, with a maximum of 1.38% for the national PTC/ITC scenario, and a minimum of .36% for the sub-NERC No Policy scenario[9]. Curtailment, on the other hand, does not respond the same in all policy scenarios. In the No Policy and RPS scenarios, curtailment decreases as the system size expands, which is expected. However, in the PTC & ITC scenario, curtailment actually increases, due to the much higher proliferation of wind and solar energy. Rather than drawing policy implications, these results suggest that curtailment will decrease as the system size expands, until a certain level of wind and solar generation is achieved. In this latter case, electric storage would be a very useful complement to system expansion.

	sub-NERC	NERC	National
Curtailment	0.05%	0.04%	0.03%
Losses	0.36%	0.39%	0.46%
Curtailment	0.08%	0.06%	0.44%
Losses	0.42%	0.44%	0.50%
Curtailment	1.66%	1.78%	2.51%
Losses	0.72%	0.84%	1.38%

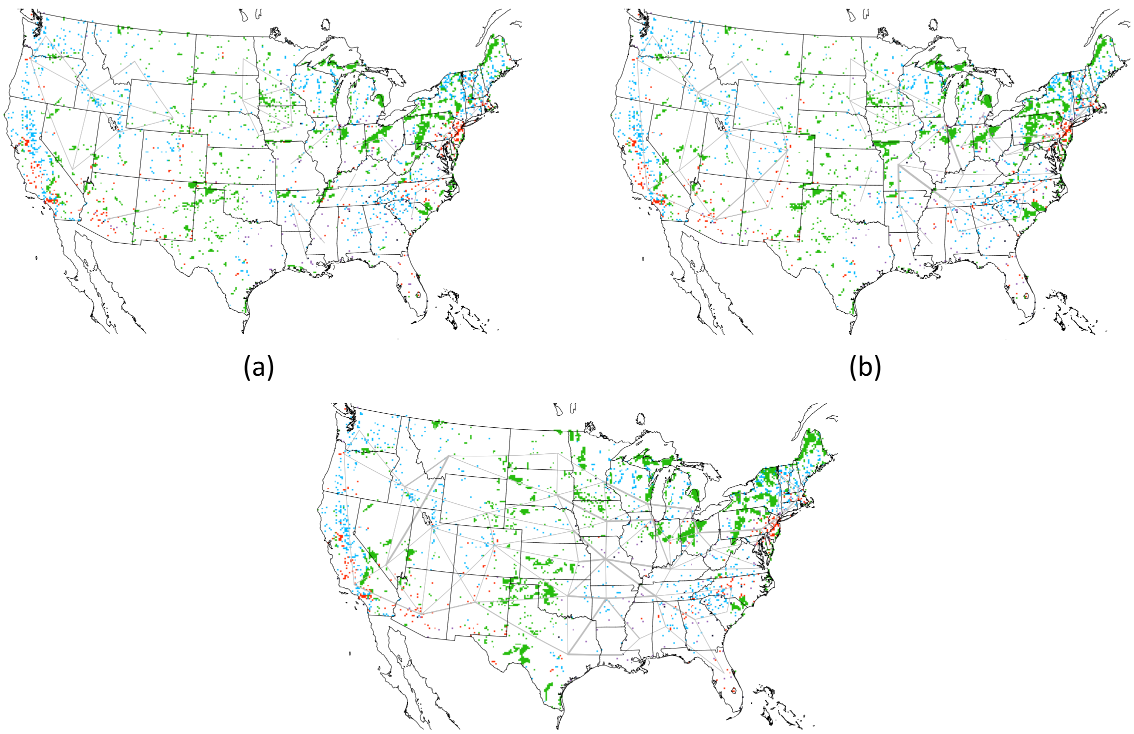
No Policy
State RPSs
PTC & ITC

Table 2: Curtailment and losses in each system and policy scenario

A key question in this study is how utilization of resource-rich locations is impacted by the expansion of markets and power system operations. **Error! Reference source not found.** shows a geographic representation of generation siting and transmission networks for each cost-optimal system with the PTC and ITC policies incorporated. These images were generated during the output process of the NEWS model and provided by Dr. Clack. Each point represents the siting of a particular technology, but does not reflect capacity. Additionally, while the transmission lines drawn for the national system represent the

[9] In 2013, losses were around 5%, largely from distribution networks not modeled here, which explains gap (EIA, 2015).

built HVDC lines, the networks for the regional systems are HVAC. Lastly, it is important to notice that not all of the allowed transmission lines connecting adjacent states have been built. Rather, the resulting lines are determined in the optimization, reflecting where transmission would be most valuable. The proliferation of carbon-free generation in the national system scenario is clearly shown in the massive growth of wind generating locations particularly throughout the Midwest and Northeast regions. Only in this larger national system (Figure 23c) is there is substantially more wind deployment in the Great Plains region in the Central U.S., an extremely rich resource for wind power. With transmission unconstrained by institutional boundaries on the national level, the national system elects



(a) (b) (c)

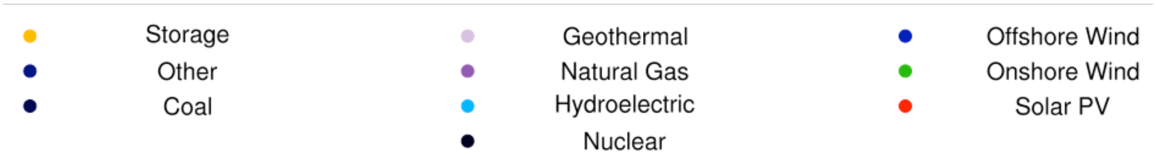


Figure 23: Cost-optimized electric power systems with federal renewable energy incentives implemented – the production tax credit and investment tax credit. (a) sub-NERC regions (current markets); (b) NERC regions (regional expansion); (c) national system. (Source: Clack, 2015)

to develop extensive transmission networks in these regions to connect neighboring states. These networks allow wind generation from largely unpopulated areas to reach consumers in both the Eastern and Western Interconnections, enabling a better alignment of generation capability and load demands.

While **Error! Reference source not found.** represent only the geospatial distribution of generating technologies, Figure 24 details the installed capacity for wind and solar PV on a state level. In this case, I present the scenarios with state RPSs implemented. On the national level, there are substantial expansions from the 2012 system for both wind and solar PV, which had 59.5 GW and 2.5 GW at the utility-scale, respectively. The smallest-growth scenarios represents over double installed capacity for both wind and solar. Interestingly, solar deployment is most prominent in the sub-NERC and NERC scenarios, requiring three times the installed capacity today, but decreases in the national scenario. I will discuss this below. Wind deployment, on the other, increases with the expansion scenarios, achieving nearly four-fold wind in the national system. While these predictions would require substantial investments by 2030, they are not unlike other studies such as DOE's 20% wind study for 2030.

It is immediately clear that Texas dominates the renewable front in terms of both solar and wind capacity. While true today for wind, this makes sense because Texas has by far the greatest electric load and is functionally "isolated" from its neighboring states that reside within their own separate interconnections. While the NERC system does not appear much different from the sub-NERC system, there are more noticeable changes with the national system. As Texas becomes connected in the national system, it is able to utilize the wind resources to the north, particularly in Oklahoma and Kansas. This explains the proliferation of wind throughout the Great Plains region as enabled in the national system scenario. Interestingly, it appears that the solar capacity reduced in Texas is shifted to California. Here, the HVDC transmission built to connect California to neighboring states enables the rest of the nation to benefit from the Southwest's rich solar resources. While solar capacity remains at similar levels between the two regional systems, it actually decreases in the national system. In this case, the significant expansion of wind capacity becomes more cost-competitive than continued solar deployment.

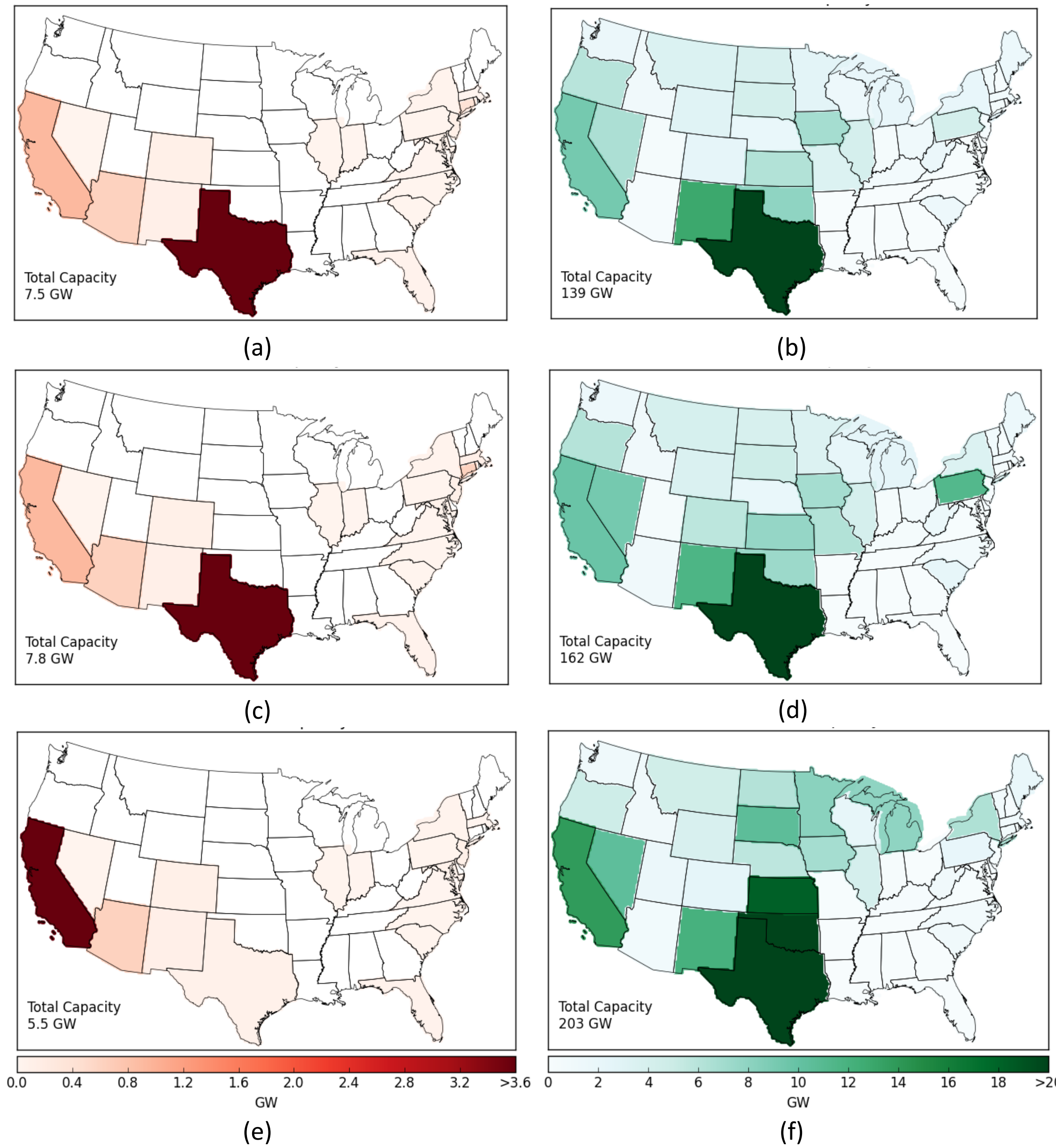


Figure 24: State capacities for solar PV (a,c,e) and wind (b,d,f) with state renewable portfolio standards implemented. (a,b) NERC Subregions; (c,d) NERC Regions; (e,f) National HVDC System.

While Texas has remained isolated as its own Interconnection in order to elude FERC regulation of interstate commerce, constructing individual HVDC lines across would not significantly compromise this desire. In fact, several DC lines already exist to connect the remaining Interconnections, just as they do between the Eastern and Western Interconnections. Only these lines would be subject to FERC regulation, a very difference scenario than if Texas implemented a whole network of transmission connecting neighboring states. Therefore, it is certainly possible that these developments would be agreeable to Texas, especially given the opportunity to substantially expand wind and solar generation capability.

The modeling results demonstrate that a national system outperforms the sub-NERC and NERC regional systems in terms of key criteria, including renewable energy generation and capacity installments, emission reduction, and electricity costs. In fact, the marginal benefits are in most cases more than double in the national scenario than the NERC regional expansion scenario. While all policy scenarios suggest this relationship, the federal renewable energy incentives especially enhance these marginal benefits, demonstrating the importance for their continuation in context of power system expansion and renewable energy integration. Of course, these relationships depend on the extent of regional expansion. If the regions expanded beyond the NERC boundaries, the systems would likely appear more similar. However, the very reason these regional scenarios were chosen was due to the balkanized institutional framework of the power grid, which is deeply engrained in the industry's history. From the current sub-regions modeled in other prominent models such the EIA's NEMS model, RFF's Haiku model, and EPA's eGRID model, the clear natural regional expansion was to the 8 NERC regions.

Chapter 4: Transmission Expansion and Integration

Markets would not be able to function without adequate transmission – the key, enabling infrastructure behind all bulk power system operations and market transactions. Indeed, the national system scenario modeled above depends on the construction of a national transmission network. By expanding transmission, markets can likewise be expanded to realize these benefits. In this chapter, I explore the physical implications of transmission expansion as well as the institution challenges facing planning and development today. Regardless of the extent of expansion that might occur, these barriers must be overcome to successfully integrate high volumes of wind and solar energy, whether on an interstate, regional, or national level.

4.1: Renewable Energy Transmission Initiatives

In the coming decades, transmission expansion will be vital in the integration of wind and solar energy resources, which would require even more transmission than simply expanding conventional generation. Some of the most renewable resource-rich sites, such as in the central Great Plains or the Southwest desert region, are located in remote areas far from major load centers and will require long transmission lines to access them. In contrast, fossil fuel or nuclear-fired power plants use fuels that can be physically transported and, therefore, can be built much closer to load centers and require less transmission investments (MIT, 2011). Some transmission studies have considered the costs and benefits of building shorter transmission lines to less resource-rich sites closer to load centers and have actually found it more cost-effective to build the longer lines (DOE, 2008; NREL, 2012). This is because lower quality sites require more generation capacity installed for a given amount of energy, which increases costs much higher than the cost of the additional transmission (NREL, 2012). Achieving the greatest, cost-effective penetration of wind and solar resources, therefore, will involve building long transmission lines to resource-rich, remote areas.

As a result, California in 2007 launched the Renewable Energy Transmission Initiative (RETI) to explore the best options for planning and siting transmission to access remote renewable resources. The effort was primarily motivated by California's RPS, at that time

33% renewables by 2020, and is significant in demonstrating how transmission expansion can be motivated by the need to integrate renewable energy rather than by a desire to relieve transmission congestion. Through RETI, CAISO was able to establish a plan for constructing transmission lines and connect major cities to resource-rich sites. Examples of such transmission initiatives include the Sunrise Powerlink, which connected 1.3 GW of wind, solar, and geothermal sites in the Imperial Valley to San Diego, as well as the Tehachapi Renewable Transmission Project, which brings 4.5 GW of wind (and solar when there isn't wind) to the greater Los Angeles areas (Weisenmiller and Picker, 2015).

New infrastructure must also be developed to provide greater regional connection and physical capacity. While this type of transmission expansion will be necessary to meet growing demand regardless of the sources used for generation, adequate transmission capacity will provide additional support for wind and solar integration. Regional transmission (1) helps realize the benefits from diversity and reduced net variability over larger geographic areas; (2) reduces congestion and provides an outlet for over-generation, both of which reduce potential for curtailment; (3) enables more robust reserve sharing, which would reduce required capacity and associated costs; and (4) supports development and operation of competitive, organized wholesale markets, which, of course, help facilitate many of these previously listed benefits. It is likely that large portions of the existing transmission network will become reusable as fossil fuel-fired plants shut down and retire, but this freed transmission capacity will not be enough to compensate for new transmission development. Because retailers in many states will need to increase their purchases of renewable energy in response to state RPS requirements, greater regional coordination and transmission expansion essential.

These regional motivations are also present in California and the Western Region.
A recent letter from the California Energy Commission (CEC) and California Public Utilities Commission (CPUC) to the president of CAISO discusses the revitalization of a new effort: the Renewable Energy Transmission Initiative 2.0. Particularly motivated by California's new RPS of 50% by 2030 and new GHG emissions standards, as well as the recent EIM, California will need to facilitate the planning of new transmission lines to

reach remote renewable resources as well as connect neighboring states (Weisenmiller and Picker, 2015). The Western Renewable Energy Zones (WREZ) initiative across the Western Interconnect also demonstrates intention for regional coordination and collaboration. Established by the Western Governors' Association (WGA) and the DOE in 2008, this effort involves participation from 11 US states, 2 Canadian provinces, and areas of Mexico, and among regional stakeholders (MIT, 2011). In particular, WREZ assesses potential for renewable energy projects across the larger Western Interconnect by first identifying the best renewable resources, then developing conceptual plans, and finally use modeling for assessment to propose final transmission projects. These examples demonstrate the desired direction of today's grid transition in expanding infrastructure to integrate renewable energy.

The current processes that facilitate transmission planning, siting, and development have made expansion efforts extremely difficult, however, especially on an interstate and regional level. This is significant because transmission investments required to support wind and solar will need to cross state boundaries and in some cases across the domains of formally organized power markets. As the grid has become more interconnected, interregional lines have become all the more important, but ironically all the more difficult to site. While regional and interstate initiatives are and will be necessary, the current institutions are not conducive to achieving improved coordination on that level. These issues and key barriers are discussed next.

4.2: Barriers to Transmission Expansion

The result of no strong federal role is (1) a sub-regional and state-driven system with independent planning entities that often disagree and obstruct coordination and wide-area planning; (2) no consistent cost-allocation process for investors to fairly recover development costs; and (3) challenges in siting new transmission facilities due to ability of an individual state to obstruct a multistate effort. These issues are relevant whether planning short-term, incremental transmission to increase reliability, connect generation, or reduce congestion, or long-term to prepare future needs of the power system. Resolving these key institutional barriers of planning, siting, cost-allocation and recovery will be necessary to develop the most cost-effective and efficient transmission networks to support wind and solar power integration and utilize the best wind and solar resources around the nation.

Transmission Planning and Siting:

Transmission planning is currently conducted by various regional or subregional groups across the U.S., as seen in Figure 25. ISOs and RTOs typically plan transmission projects within their respective regions, but in the remaining areas without such institutions, utilities often only consider local projects and needs without regard to the benefits that could be gained from coordination. In order to coordinate in these areas, numerous groups would be required to collaborate and plan together. For example, while connecting states with differing electricity rates will result in lower regional costs overall, prices for states with low costs will likely rise in the short-term (as states with higher rates initially benefit). Arizona has cheaper costs than California, and may experience this initial rise in prices. Because there are so many stakeholders invested in each project, ranging from investors to public leaders and environmental communities and advocacy groups, both intrastate and interstate, coordination can be difficult to achieve.

Similarly, although FERC is the primary governing body over wholesale electricity markets and interstate electricity commerce, the Federal Power Act of 1935 passed by Congress left responsibility of *siting* in the hands of states. Multistate transmission efforts therefore require complete cooperation, and one state or agency has the ability to essentially veto the siting proposal. Furthermore, proposals for lines that cross federally owned land, which covers 30% of the U.S. must be approved by the respective agencies (often many become involved) and reviewed under the National Environmental Protection Act (MIT, 2011). This issue is often highlighted in the Northwest where a greater density of such federal agencies resides. As a result, projects are often objected to and annulled pursuant to state or federal statutes for various reasons such as environmental degradation or costs. While the Energy Policy Act of 2005 attempts to grant FERC limited "backstop" authority over transmission siting, it was largely unsuccessful and will be discussed later.

Interestingly, the Natural Gas Act of 1938, which was passed just three years after the Federal Power Act (and later amended in 1947), grants FERC authority with "eminent domain" to regulate and site interstate natural gas pipelines (MIT, 2011). This means that FERC has authority over states in siting these projects. This level of authority was not granted to FERC in terms of electric power transmission because at the time the electric power industry was viewed as more of a local and regional industry that did not require federal intervention in transmission siting. This contrast has been apparent, though, in the amount of interstate infrastructure developed for electricity transmission versus natural gas pipelines: for example, between 2000 and 2010, a mere 748 miles of transmission were constructed, compared to 13,000 miles of pipeline, that crossed state borders (Wellinghoff, 2010). Arguably, the power industry structure and environment is now much different than in the 1930s and a much stronger case can be made for giving FERC greater authority over transmission siting.

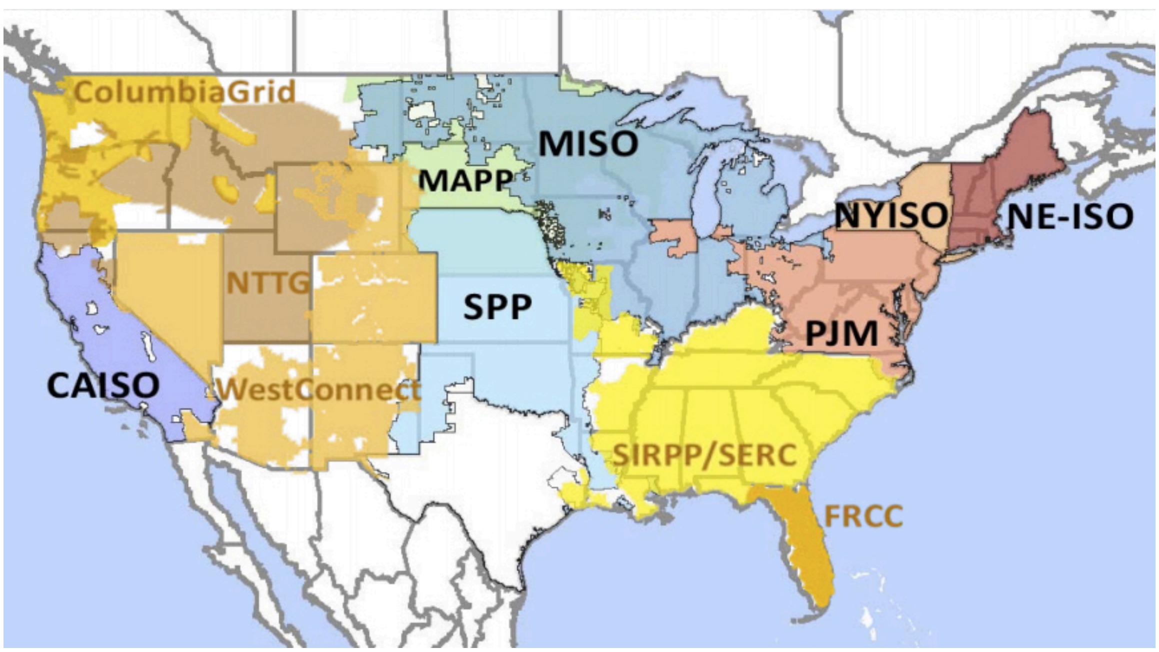


Figure 25: Transmission planning region under Order No. 890. (Source: FERC, 2011)

Cost-Allocation and Cost-Recovery:

The allocation of costs is the process by which transmission investors recover the costs of their investments. When individuals or entities decide to financially support a transmission project, a key factor in incentivizing the new plans and development is assurance that costs can be recovered. Because transmission is open-access and non-discriminatory by law – i.e. a collectively shared public facility – some parties take advantage of the resource without paying, while others bear more of the burden. As a result, parties do not want to pay significant amounts of money towards projects that will bring others more benefit than themselves. Developers must therefore be able recover the high costs of transmission investment from the customers who benefit from and use the new lines.

Currently there is no standardized cost-allocation method. This leads to negotiations for each project, and costs of lines that cross boundaries are subject to project-specific allocations among the involved parties. In regions with organized markets, costs are typically recovered separately through wholesale tariffs (FERC regulated). In other regions, vertically integrated utilities recover costs through state-regulated "bundled" retail rates. In either case, retail electricity rates may increase or decrease depending on whether the additional transmission is well utilized and enables access to cheaper electricity sources. The lack of a fair, standardized, and predictable method for transmission cost allocation is becoming a much greater issue in the planning and development of new interstate lines, particularly as it is difficult to incentive transmission investment (DOE, 2008) without greater certainty in cost recovery. This has created a sort of "chicken-and-egg" dilemma: because building a wind plant, for example, is much quicker than building the transmission necessary to deliver the power to markets, companies do not want to build plants that will be inactive for long periods of time before transmission is built, or without assurance that the lines will in fact be built. On the other hand, transmission investors do not want to commit to build lines before generation capability has been demonstrated. Currently, Texas is facing this issue in developing wind generation through its Competitive Renewable Energy Zones (CREZ) project. Ideally, Texas aims to plan transmission before generation is built because transmission takes much longer to develop (about 2 versus 10 years) (MIT, 2011).

This issue particularly reflects difficulties resulting from the separation of the transmission and generation responsibilities that previously resided jointly in the hands of the vertically integrated utilities. As the primary governing body over wholesale electricity transactions and interstate electricity commerce, FERC is responsible for determining the allocation of costs through its approved rates. In recent years FERC has adopted regulations to mitigate issues of transmission siting and cost-allocation, in promotion of renewable integration through regional and interstate transmission expansion.

4.3: The Role of Federal Regulation

Since 2005, Congress and the FERC have passed several crucial orders towards the improvement of the transmission expansion process, the most recent of which in 2011 specifically acknowledged some of the new challenges of renewable energy integration. While these new FERC rules establish precedent for future reform, and demonstrate recognition from the federal government of the importance of these issues, many complications in the process regarding transmission siting, cost-allocation and recovery, and planning are still unresolved.

EPAct of 2005

Realizing a decline in transmission investment and recognizing the need for better interstate coordination, Congress in the EPAct of 2005 granted FERC very limited "backstop" authority in siting interstate lines. This regulation applies in the case that the DOE determines that the proposed transmission project is part of a few areas designated by the FERC as "national interest electric transmission corridors," and that the project has stalled – hence, requiring intervention (i.e. from FERC) (DOE, 2008). However, now largely due to court cases in recent years, much of this authority has subsided and the FERC can only overrule a state decision if the plan is not dealt with in a "timely manner" (about a year) (NREL, 2012; MIT, 2011).

FERC Order 1000

In July 2011, FERC issued Order No. 1000 to improve wide-area, interstate transmission planning and cost-allocation processes. This reform represents yet another initiative spearheaded by FERC that encourages and recognizes the importance of regional coordination and now, renewable energy integration. Specifically, Order 1000 first encourages greater coordination between regional and interregional transmission planning entities. Each region is required to develop a regional transmission expansion plan, as well as consider potential of expansion between neighboring regions. The transmission planning regions that have formed in accordance to Order 1000 are depicted in Figure 26, which demonstrates wider-area groups compared to those following FERC Order 890 (Figure 25), but still many sub-regional divisions. Secondly, the Order requires that these entities devise transparent and common cost-allocation methods in their respective areas and between neighboring regions (FERC, 2015). Potential allocation methods could include assigning costs in proportion to estimated benefits (beneficiary-pays principle), or assigning them uniformly (e.g., per-KWh) equally across a region (socialization) (MIT, 2011). These different methods could potentially be applied in

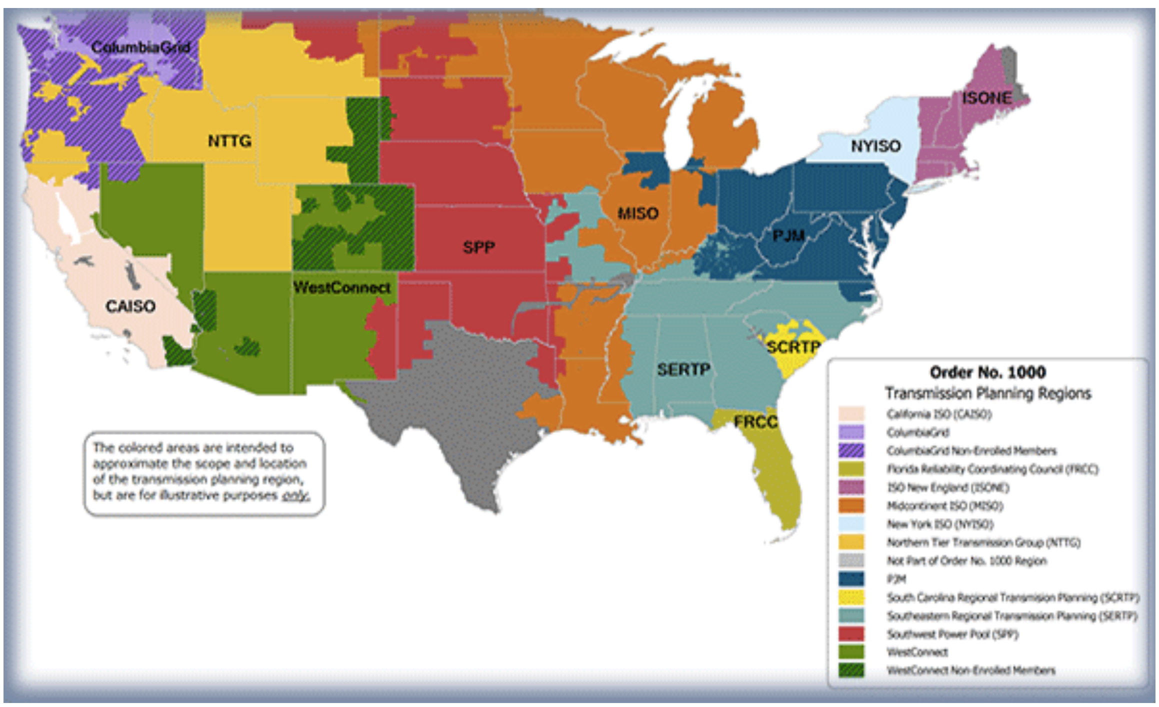


Figure 26: Transmission planning regions under Order No. 1000. (Source: FERC, 2015)

different scenarios depending on the reason for transmission, whether for reliability (uniform allocation) or economic benefits (based on who benefits most). Enacting this more consistent process will help remove uncertainties investors might have in terms of cost-recovery and alleviate the need for lengthy negotiations. Lastly, the Order also requires consideration of public policies such as renewable energy mandates (e.g. state

RPSs) in assessing new transmission needs as an additional factor beyond reliability and economic impacts (FERC, 2015). This specific acknowledgement regarding the importance for renewable energy integration is unique and again demonstrates its emerging role in shaping power industry reform.

Historically, most major developments in the U.S. power industry that involved the incorporation of new generation required parallel efforts in transmission investment. These development efforts included the integration of Federal hydropower facilities in the 1930s, '40s, and '50s, nuclear and coal-fired plants in the '60s and '70s, and natural gas facilities in the `90s (DOE, 2008). The need for interstate transmission lines today reflects the lack of association of state political boundaries and renewable energy resources, which, unlike conventional fuel sources that can be physically transported for generation, are dependent on location. Allowing regional coordination would allow for more efficient and cost-effective utilization of our nation's resources. However, while FERC Order 1000 is an important first step, it is likely that stakeholders will still have many disagreements without a nationally standardized cost-allocation process, and that states will still exercise their authority to obstruct interstate projects. Several studies, including MIT's Future of the Electric Grid report, have suggested that (1) FERC should be granted greater authority to site interstate lines or lines that cross federal property; and (2) that FERC be more firm with the cost-allocation process or that it be standardized on a higher level such interconnection or federal (MIT, 2011). While the history of FERC regulation sets precedent for future reform, and most recently Order No. 1000 is an important step towards regional transmission planning, there are still issues to resolve.

Chapter 5: Conclusion

Ever since the power industry began to develop in the late 1800s, electricity markets and power utility networks have periodically undergone significant reform and restructuring. From the original small, isolated systems to the regional and interregional networks that exist today, the industry has recognized the advantages of achieving economies of scale and resource diversification that result from linking transmission and resources over wider areas. Along the way, FERC adopted market-based pricing regulation standards to encourage the development of independent wholesale generation and Congress passed legislation to require open, non-discriminatory transmission access for wholesale power transactions. FERC subsequently encouraged the development of competitive, organized wholesale markets coordinated by the RTOs and ISOs that now oversee nearly two-thirds of the power system. As seen in initiatives such as the West's Energy Imbalance Market in 2014 and FERC's Order 1000 in 2011, initiatives to reform the U.S. power grid still continue, but now driven in great part by the new motive to integrate larger amounts of renewable energy.

As of 2015, the grid is not facing particularly severe issues, and thus does not require immediate change. However, over the coming decades, renewable energy sources, namely wind and solar, will need to play a larger role in our nation's energy mix as we seek to lower GHG emissions and respond to renewable energy policies and the EPA's Clean Power Plan. The integration of these weather-driven, variable energy resources poses substantial challenges to grid reliability, and will require further reform of the electricity industry in providing greater grid flexibility. To maximize the nation's use of its full renewable resource potential, it may even be necessary to substantially reform electricity regulation by giving FERC or some appropriate federal agency (e.g., DOE) more authority to bring about a more "rationalized" national transmission grid.

One of many possible mitigation strategies that will likely play a role is wide-area power system operations – the expansion of organized electricity markets and sufficient integration of transmission over larger geographic scale. Such measures can help reduce net-variability in wind and solar power generation while enabling resource sharing and improving reliability, provide an outlet for over-generation while reducing curtailment, improve resource utilization while lowering electricity costs, and enable low-cost pollution reduction by providing a cheap alterative to fossil-fuel generation. By utilizing geographically large and interconnected networks, more wind and solar power can be efficiently shipped more often at lower costs from resource-rich areas to locations requiring energy.

Many major studies to date, including those conducted by federal agencies, have recognized or concluded that operations across greater geographic scale will be necessary to feasibly integrate high volumes of variable renewable energy sources (DOE, 2008; NREL 2012; Clack et al. 2015). Clack et al. (2015) demonstrate feasible reductions in CO_2 emissions of up to 80% of 1990 levels by 2030 using a national network HVDC transmission using the National Energy with Weather System Simulator. This thesis further contributes to this research by incorporating existing U.S. electric sector policies to reflect legislative influence, and giving context to the national system by providing a comparison of existing networks to an intermediate regional expansion scenario employing a HVDC overlay. While the remaining studies suggest the importance of greater interconnections and operations over wider geographic areas, they have not suggested the extent or general configuration of the transmission expansions needed. In this thesis, I have attempted to at least begin to address this uncertainty, and demonstrated the substantial merits of a national system over that of a potential regional expansion scenario.

Further scenarios could also be simulated using the NEWS model. First, as this study only applied state RPSs and the federal incentives separately, it would be useful to observe the combined policy impacts. The incorporation of existing cap-and-trade programs in California's AB 32 legislation and RGGI, which have already been modeled but not yet simulated, would further enhance the modeling suite as well. In place of sub-NERC and NERC regionals, it could also be valuable and more accurate to model FERC regions and an intermediate regional expansion to the interconnection level or the 5 regional RTOs proposed in 2001 (shown back in chapter 2). However, as the results here are similar to the previous geographic scaling study using different regions, the results are likely to be similar for FERC market region expansion, and of course the national system remains the same. Lastly, as the challenges with integration become more prominent with higher volumes of wind and solar, as seen in the PTC and ITC national scenario with increasing curtailment. A future study could require a minimum amount and compare metrics such as costs and curtailment between the systems at these levels.

Wide-area coordination and integration will not only require growth of organized electricity markets but also transmission networks. While market operations facilitate power transactions, transmission is the key, enabling infrastructure. However, to achieve such reform and restructuring, there are significant institutional challenges that must be addressed. These are particularly prominent with the endeavor of transmission expansion. FERC's Order 1000 will encourage a more regional planning process as well as improve the process of cost-allocation, but there is still much to be done. Transmission siting remains a key obstacle, particularly as states have authority to obstruct any multi-state effort. In this case, it seems that there would be benefits in granting FERC greater authority over these siting decisions to reduce rejection of state initiated proposals, just as it has exercised authority over the approval of natural gas pipelines since 1938.

While the implementation of a national system would be a significant project, it is not unlike the development of the national railroad or highway systems in place today. However, that does not necessarily mean it is the right option. It will first be difficult to undertake such a major infrastructure change across the entire nation. While the benefits might compensate for the costs, this project would be difficult, as it would require coordination throughout the entire nation. It could potentially create security issues, including vulnerability to wide-area blackouts cyber attacks, the latter of which is becoming especially a concern in the modern era (MIT, 2011). Regional expansion will still bring benefits and could potentially be implemented through regional overlays connecting remote sources to load centers, or more linkages between the interconnections. Such a regional system would also supports the regional environmental policy and multi-state collaboration strongly encouraged in the EPA's Clean Power Plan.

However, while other solutions will likely come into play as well, such as large-scale storage if the technology becomes economically feasible, some form of wide-area expansion will likely be necessary and beneficial. Whether on the regional or national level, such efforts could (1) resolve issues of inevitable interstate transmission to access remote resources; (2) reduce the burden of any one mitigation technique while bringing regional benefits; and (3) enable more immediate action (without waiting for new technologies to develop). While not without obstacles, renewable energy integration has already demonstrated a role is shaping market and transmission reform across the electric power industry, and making these transitions and convincing politicians must start with analysis and modeling results such as these.

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Appendix A

A.1: Boundary Modeling Methodology:

State Boundary Modeling:

In order to reflect current political divisions and conduct state-level analysis, it was necessary to incorporate state boundaries into the model. This involved assigning model grid points to states, as well as transferring existing regional components to those boundaries, including hourly load data, potential generation sites for wind, solar and conventional sources, and nuclear and hydro generation. Additionally, an expansion from the original 32 nodal areas to 48 nodal areas required new HVDC nodes, or load centers for HVDC transmission – one for each state. In this case, various siting alternatives were considered, including the most populous city of each state, the centroid of the top five most populous cities, and a population-weighted centroid of the top five most populous cities. We then established new transmission lines by linking nodes in adjacent states, and calculated distances between the nodes. These HVDC node distances are supplied exogenously, while resulting transmission is determined endogenously given a .5% loss per 100 miles. Finally, new HVAC transmission loss coefficients are supplied exogenously for each state as 1% loss per 100 miles, representing power remaining after transmission between each generation site to the load center.

State Boundaries:

State boundaries were determined using a Global Administrative Areas shapefile of the contiguous 48 states. Each of the ~151,000 latitude and longitude grid points comprising the model space were assigned to a state (or none if located in the ocean). This created a ~150,000 x 48 binary matrix flagging grid points to state boundaries. Subsets of the grid points were additionally assigned to states, including potential generation sites for wind and solar, and existing generation (including conventional) in 2012 that the model assumes pre-optimization.

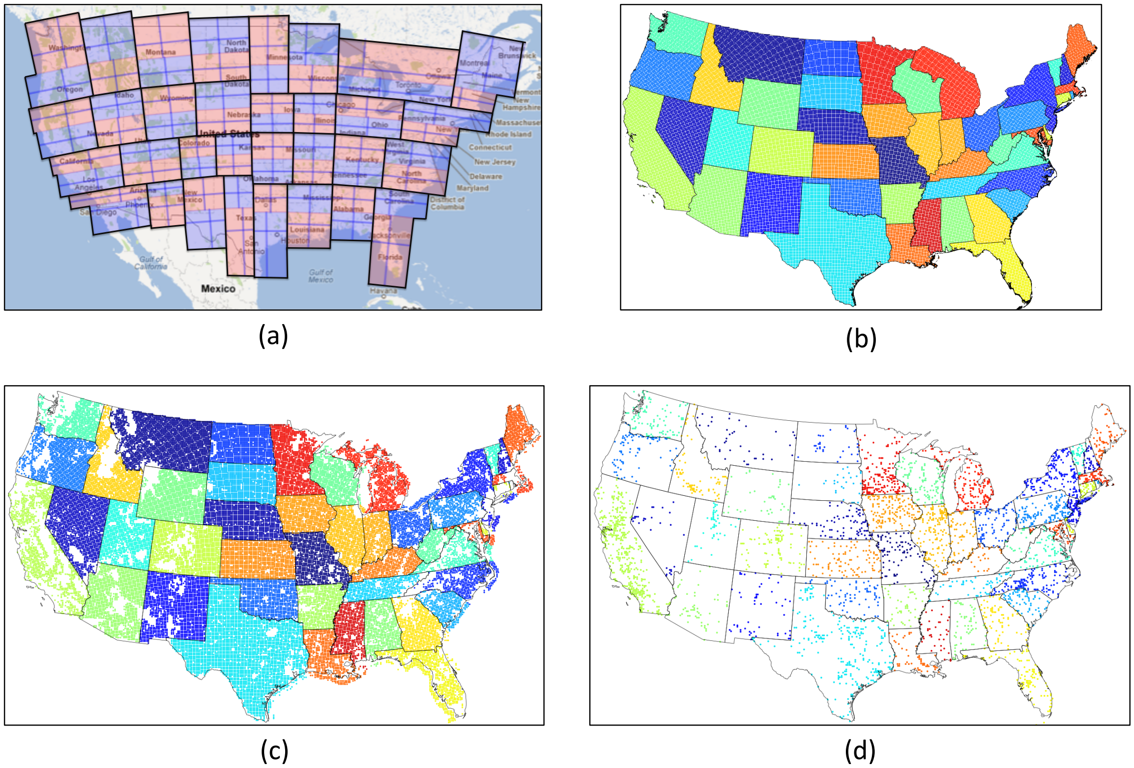

Figure 27: The transformation from the original 32 NEWS regions to state boundaries. (a) The original 32 regions, created by repeatedly dividing U.S. land area vertically and horizontally; (b) all land model grid points mapped to the 48 states; (c) all available wind and solar generation sites mapped to states; (d) the existing generation sites in 2012 mapped to states.

4.1.2: State Hourly Load, Nuclear and Hydroelectric Generation:

Prior to state boundaries, the NEWS model consisted of 32 regional nodal areas. Each nodal area was assigned a unique hourly load requirement, as well as hourly generation for nuclear and hydroelectric. Replacing the 32 regional areas with 48 state boundaries therefore required a new assignment of these load and generation datasets. Assuming equal division of load and generation within each region, we calculated the fraction of each region in state, and used these coefficients to multiply the hourly load and generation in each region for each state. Summing regional load fractions for each hour and state yielded the new state hourly load, state hourly hydroelectric generation, and state hourly nuclear generation.

Likely due to the complexity of how the hourly electricity demand was originally established, there appears to be some state irregularities and improper assignment here. The FERC 714 form contains hourly load reports from a range of power supplying entities, including balancing area authorities and utilities. Many of these entities are regional and cross state borders or even overlap in domain (because of the range of entities reporting). In the original assignment of load to the NEWS regions, which relied on a city population-weighting method, it's possible that load got assigned incorrectly on the state level. For example, it appears that California has lost some demand to Nevada (Reno) and Arizona (Phoenix). Additionally, New York has likely lost some load to Pennsylvania and Ohio. The process of translating the original NEWS region components to state boundaries can be improved, though. Rather can using the fraction of each region in state as the multiplier, a more accurate factor would be state electricity consumption. This improved conversion has already been completed, and will likely be applied in future NEWS studies.

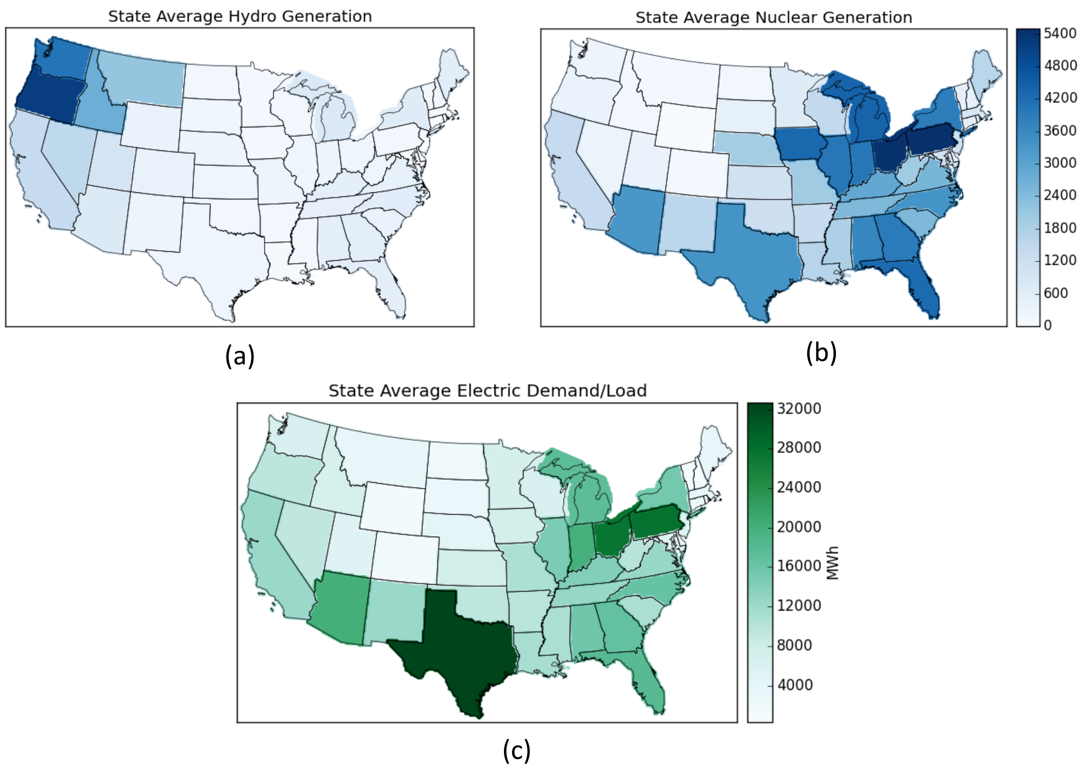

Figure 28: State averages for hourly hydroelectric generation (a), nuclear generation (b), and electric load (c) for the years 2006-2008. These are crucial model inputs. The electric load must be matched at each hour of the year. Nuclear and hydroelectric generation is pre-determined, allowing realistic deployment of other technologies to meet the remaining demand.

State HVDC Nodes:

The transition to state boundaries and 48 nodal areas also required relocation of HVDC nodes, or load centers – one for each state. We considered several siting locations. These included node placement in the most populous city in each state, the centroid of the top five most populous cities, and the population-weighted centroid of the top five most populous cities. The population data came from U.S. Census Bureau population estimates for 2014 subcounty populations, which we filtered and sorted to yield top five city populations in each state. Given this new city dataset, we then used a geocoding algorithm drawing from an ArcGIS server to collect coordinates for each city. This final dataset of city populations and coordinates enabled the determination or calculation of each of the three load center types.

HVDC Node Distances and Nodal Area HVAC Losses:

A crucial consideration in the model is transmission. This includes HVDC transmission between adjacent state nodal areas, as well as HVAC transmission within each nodal area to represent power shipping between generation sites and nodes. Inherent in the transmission computations are electric losses, which vary depending on transmission type

(AC or DC), transmission load, and distance. In this model, HVDC and HVAC transmission is assigned losses of .5% per 100 miles and 1% per 100 miles, respectively.

As HVDC transmission is determined endogenously in the model, it is only necessary to supply distances between each adjacent node as inputs. The adjacent transmission constraint is due to political difficulties in shipping power entirely through state areas without in-state gain. These distances between adjacent load centers are calculated as the great circle distance in miles.

HVAC transmission loss coefficients are also supplied exogenously. This transmission represents power shipped from each generation site to the load center. Therefore, distances between each generation site (wind, solar, and conventional) can be calculated and applied to the loss formula to yield loss coefficients (a fraction representing the remaining proportion of power post-transmission).

A.2: NEWS Simulator Mathematical Optimization

This section details the mathematical optimization in the NEWS model necessary to understand the policy modeling methodology in Appendix A.3. The optimization is comprised of several different components, including a cost-minimization process, load and transmission constraints, and various other equations. The cost-minimization and load constraints relevant to the policy modeling are detailed below, as documented in Clack et al. (2015).

Cost-Minimization:

The NEWS model is currently designed to find this cost-optimal system. This entails solving and minimizing the objective cost function parameterized by all costs for variable generation, conventional generation, and transmission. This equation will be modified later to include the PTC and ITC.

The objective cost function:

$$\begin{aligned} Minimize\ \psi = \sum_{\emptyset}\sum_{\kappa}(\mathcal{C}^{v}_{\emptyset\kappa}\cdot V_{\emptyset\kappa} + \mathcal{V}^{v}_{\emptyset\kappa}\cdot V_{\emptyset\kappa}\cdot \sum_{\tau}\mathcal{W}_{\tau}) + \sum_{\mu}(\mathcal{C}^{g}_{\mu}\cdot G_{\mu} + (\mathcal{E}^{f}_{\mu}\cdot\mathcal{C}^{f}_{\mu} \\ + \mathcal{V}^{f}_{\mu})\cdot\sum D_{\mu\tau}) + \sum\sum \mathrm{T}_{\alpha\beta}\cdot\left(\mathcal{C}^{ts}_{\alpha\beta} + \mathcal{C}^{tl}_{\alpha\beta}\cdot\delta_{\alpha\beta}\right) \end{aligned} \quad (1)$$

where,
$\mathcal{C}^{v}_{\emptyset\kappa}$ = annual amortized capital cost of variable generator of type $\emptyset$ at location κ [2013$ / MW]
$V_{\emptyset\kappa}$ = installed capacity of variable generator [MW]
$\mathcal{V}^{v}_{\emptyset\kappa}$ = variable O&M cost of variable generator [2013$ / MWh]
$\mathcal{W}_{\emptyset\kappa\tau}$ = hourly capacity factor of variable generator at time τ [MWh / hr]
$\mathcal{C}^{g}_{\mu}$ = annual amortized capital cost of fossil fuel plant at location μ [2013$ / MW]
G_{μ} = installed capacity of fossil fuel plant [MW]
$\mathcal{E}^{f}_{\mu}$ = heat rate of the fossil fuel plant [MMBtu / MWh]

$\mathcal{C}_{\mu}^{f}$ = fuel cost for fossil fuel plant [2013$ / MMBtu]
$\mathcal{V}_{\mu}^{f}$ = variable O&M cost of fossil fuel generator [2013$ / MWh]
$D_{\mu\tau}$ = fossil fuel generation at time τ [MWh]
$\mathrm{T}_{\alpha\beta}$ = capacity of HVDC transmission line between nodes α and β [MW]
$\mathcal{C}_{\alpha\beta}^{ts}$ = cost of each HVDC transformer station pair [2013$ / MW]
$\mathcal{C}_{\alpha\beta}^{tl}$ = cost of each HVDC transmission line [2013$ / MW-mile]
$\delta_{\alpha\beta}$ = length of HVDC transmission line [miles]

Load Constraint:
Another crucial constraint in the NEWS model is that electrical load must be matched by supply at each hour of the year. Equation 2 establishes this constraint, requiring that combined variable and conventional generation must equal the load in a certain area at every time-step (hour), minus transmission fluxes and excess generation. This equation will be useful in establishing the state renewable portfolio standards.

$$\begin{aligned}\sum_{\emptyset}\left(b_{\emptyset\omega}^{v}\cdot\sum_{\kappa}V_{\emptyset\kappa}\cdot\mathcal{W}_{\emptyset\kappa\tau}\right)+\sum_{\mu}b_{\mu\omega}^{c}\cdot\left(D_{\mu\tau}+N_{\mu\tau}+H_{\mu\tau}\right)\\=\mathcal{L}_{\omega\tau}-F_{\omega\tau}+E_{\omega\tau},\qquad\forall\omega,\tau\end{aligned}\tag{2}$$

where,
$b_{\emptyset\omega}^{v}$ = nodal area of variable generator of type $\emptyset$ in regional market area ω
$b_{\mu\omega}^{c}$ = nodal area of conventional generator (fossil fuel, nuclear, hydroelectric) at location μ in regional market area ω
$N_{\mu\tau}$ = nuclear generation at location μ at time τ [MWh]
$H_{\mu\tau}$ = hydroelectric generation at location μ at time τ [MWh]
$\mathcal{L}_{\omega\tau}$ = electrical demand/load in regional market area ω at time τ [MWh]
$F_{\omega\tau}$ = HVDC transmission power flux in regional market area ω at time τ [MWh]
$E_{\omega\tau}$ = excess generation in regional market area ω at time τ [MWh]

A.3: Policy Modeling Methodology

This section describes mathematical modeling behind the policies discussed in chapter 3. These include the PTC, ITC, and state RPSs.

Renewable Portfolio Standard:
The RPS is modeled as a load constraint. The yearly variable energy generation must be at least as large as the RPS fraction of the electrical load in each relevant area (state).

RPS as percent requirement:

$$\sum_{\emptyset}\sum_{\kappa}\sum_{\tau}V_{\emptyset\kappa\omega}\cdot\mathcal{W}_{\emptyset\kappa\tau\omega}\geq\sum_{\tau}\left(\mathcal{L}_{\omega\tau}-F_{\omega\tau}\right)*\mathcal{R}_{\omega}+E_{\omega\tau},\qquad\forall\omega$$

where,

$\mathcal{R}_\omega$ = the renewable portfolio standard for market area ω [unitless fraction]

RPS as power requirement:

$$\sum_{\emptyset}\sum_{\kappa}\sum_{\tau} V_{\emptyset\kappa\omega}\cdot\mathcal{W}_{\emptyset\kappa\tau\omega} \geq \mathcal{M}_\omega - \sum_{\square}(F_{\omega\tau} - E_{\omega\tau}), \qquad \forall\omega$$

where,
$\mathcal{M}_\omega$ = the renewable portfolio standard for market area ω [MW]

A.3.2: Production Tax Credit:
This subsidy can be modeled as a subtraction from the variable O&M costs for variable (wind) generation:

$$\sum_{\emptyset}\sum_{\kappa}(\mathcal{C}^{v}_{\emptyset\kappa}\cdot V_{\emptyset\kappa} + (\mathcal{V}^{v}_{\emptyset\kappa} - \mathcal{S}_\kappa)\cdot V_{\emptyset\kappa}\cdot\sum_{\tau}\mathcal{W}_\tau)$$

where,
$\mathcal{S}_\kappa$ = the production tax credit for variable generator type κ [2013$ / MWh]

Investment Tax Credit:
The ITC incentive can be represented as a fraction of the variable generator's capital costs:

$$\sum_{\emptyset}\sum_{\kappa}((1-\mathcal{I}_\kappa)\cdot\mathcal{C}^{v}_{\emptyset\kappa}\cdot V_{\emptyset\kappa} + \mathcal{V}^{v}_{\emptyset\kappa}\cdot V_{\emptyset\kappa}\cdot\sum_{\tau}\mathcal{W}_\tau)$$

where,
$\mathcal{I}_\kappa$ = the investment tax credit for variable generator type κ [unitless fraction]