The Future of the Grid

Evolving to Meet America's Needs

Hosted By

and

Southeast Region Workshop

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WELCOME LETTER

Dear Workshop Participant:

Thank you for participating in the U.S. Department of Energy's (DOE's) Office of Electricity Delivery and Energy Reliability (OE) and GridWise Alliance's (GWA) Southeast Region "The Future of the Grid" Workshop. Your input is critical because this workshop will not only help to develop the Southeast Region's stakeholder-driven vision for our future electrical grid, but it also will serve as the Region's contribution to the broader national vision for the future of the grid.

The electrical grid – as an enabling technology – provides the foundation for America's economic success. Our digital economy, our national security, and our daily lives are highly dependent on reliable, safe, and affordable electricity. The electricity industry is now in the midst of a major transformation that likely will continue for the next two decades. By having thoughtful and provocative conversations now, we can help ensure that electrical grid reliability and security are maintained now and well into the future while encouraging innovation, and fostering economic growth during this transition period.

Our goals for the Southeast Region Workshop are broad and ambitious. We will debate and discuss many challenges facing the electricity industry. To help maximize utilize our time during the workshop we have compiled this document to describe the scenarios we will be discussing, as well as to provide a summary of relevant industry information. Please take a few minutes to familiarize yourself with these materials, so we can have a richer, more informative, and productive workshop.

We look forward to hearing your view on these important issues and anticipate that the Southeast Region Workshop's outcomes will provide significant direction and insights on the stakeholder's vision for the future of the grid.

Sincerely,

Becky Harrison

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INTRODUCTION

It is an exciting time in the electricity sector, as major changes transform the way we generate, deliver and use electricity. These changes are being driven by both new policies and new technologies. Furthermore, the dynamics of the consumer's role in these changes and the need to maintain a secure electrical grid governed by prudent regulations are combining to create a healthy debate that will no doubt take years to play out.

Regardless of our ultimate generation resource mix or production method (i.e., large scale central plants versus smaller-scale distributed plants), our electrical grid and its operation will always play a critical role in our future electricity infrastructure. In fact, the operation of our grid will become more and more complex even as it becomes more critical to the security of our nation's economy in a manner analogous to the ways the cellular network has enabled the world of smart phones and mobile applications.

There are a number of issues facing the electricity industry today. We recognize that while these are issues faced by the industry in general, they have regional and local differences that are important to understand as we explore how best to modify policies and invest in technology development.

We recognize that without thoughtful debate and planning these changes could result in unintended consequences that hinder productivity and innovation. With this in mind, the GridWise Alliance (GWA) and the U.S. Department of Energy Office of Electricity Delivery and Energy Reliability (DOE OE) are partnering to facilitate a series of four regional workshops in late 2013 and 2014 to develop a stakeholder-driven vision of the future grid, including its capabilities and operational requirements. This series of workshops will culminate with an executive summit in mid-2014 in Washington, DC. Our goal is to identify and characterize technological capabilities, financial models, and the modifications to policies and regulations needed to support safe and reliable electricity delivery.

These regional workshops will bring together thought leaders from all stakeholder groups including utilities, regulators, state government officials, renewable energy providers, suppliers, and industry innovators to develop the vision for the grid and grid operators in 2030. Each workshop is targeted to have approximately 60 participants to engage in a series of small, facilitated breakout discussions with their peers. The ideas from each workshop with be summarized in a brief document and provided to the participants.

The result of these efforts will inform national efforts at DOE, help guide an R&D agenda, and serve as a tool to educate all stakeholders including state and Federal policy makers and regulators. These efforts will help us develop a much better understanding of the issues that we must address to achieve the goal of an affordable, reliable, and resilient electrical system that will ensure both a vibrate national economy and protection of our national security.

WORKSHOP DISCUSSION SCENARIOS

WORKSHOP DISCUSSION SCENARIOS

Accurately characterizing what the operation of the U.S. electricity delivery system will be in 2030 is difficult and perhaps even impossible. However, in order to be prepared for the future, it is important to begin thinking and planning for it now. Individuals involved in the current operation of the grid are in the best position to understand the complexity and nuances of grid operations and how changing external factors could impact operations. There are a large number of factors that will determine how the grid must function from policy drivers, to customer expectations, to technological developments. To narrow and focus our discussion, the Workshop will focus on five main scenarios. The scenarios were selected with the hope of stimulating participants' thinking to drive innovative ideas and possibilities while simultaneously grounding them in reality and what situations are likely today. The five scenarios are not exhaustive of all possible situations but rather have been developed to try to cover a wide range of the grid landscape while also accounting for possible regional uniqueness. During the Workshop participants will be asked to engage in discussions on one of these scenarios.

SCENARIO 1: THE CHALLENGE OF BALANCING SUPPLY AND DEMAND AS GRID COMPLEXITY GROWS

Description

Today, transmission grid operators must ensure there is enough power generation both in terms of wattage and volt-amperes reactive (VARS) to service the load on their systems. To do so, the transmission grid operator continually adjusts the central generation. In some systems, they can also use a limited amount of demand response as another resource to keep the supply and load in balance. Today, for residential demand response, the operator typically sends a signal to switches on customers' air conditioners, water heaters, and/or pool pumps to cut off the load completely or cycle off for a given percentage of time in an hour. This simple but effective mechanism allows the operator to ride through a few critical peaks as an alternative to providing additional generation. In the future, with increasing penetration of distributed energy resources, the distribution grid will have to be able manage two-way power flows and must be able to balance more complex supply and demand options.

The devices on the "customer side" of the meter may include distributed generation; distributed storage; home energy management systems that can control various loads; appliances that can react to pricing signals; and options for charging or discharging electric vehicles. At the transmission level, utility-scale generation will also be changing to include increasing penetration of non-dispatchable generation such as large-scale wind farms and other renewables as well as utility-scale storage capabilities, all of which will require enhancements to existing balancing capabilities. This increasing dependence on devices at the "edge of the grid" will also require greater interaction between the distribution and transmission grid and grid operators to optimize the balancing of supply and demand functions.

Questions to Ponder

- What do these new balancing requirements mean to the role of the grid and the grid operator?
- What new demands will the increase in distributed energy resources create for the distribution grid and its operators?
- What new demands will increasing distributed and large non-dispatchable resources create for the transmission grid and its operators?
- What is the distribution grid operator's role versus the transmission grid operator's role?
- Will transmission operators need more visibility into the distribution grid?
- What new capabilities are needed to perform this role? Are new tools/models/information needed?
- How will a shifting fuel mix (e.g., reduced coal, increased natural gas, increased renewables, etc.) drive or alter grid operational needs?
- How must current policies and/or regulations change to enable these new capabilities and roles?
- What are the financial implications of this transition? How do we ensure grid operators and owners remain financially viable through the course of this transition?
- What are the implications for the future workforce, both inside utilities and third party providers?
- How must market structures evolve to handle new players?
- What is the role of each party in this Scenario?

SCENARIO 2: THE CHALLENGE OF INVOLVING CUSTOMERS AND THEIR ELECTRICAL LOADS IN GRID OPERATIONS

Description

Significant innovation is already occurring across all customer classes with smart devices now commonplace in many residences and businesses around the country. It's relatively safe to assume that by 2030 every device connected to the grid could be capable of communicating to the grid operator and receiving a control signal. Many of these will be purchased by consumers from various retail suppliers with the expectation that they will "plug and play" with grid operations. The challenge is to define an architecture and design that can optimize the loads and their responses in ways that maximize efficiency and minimize costs.

Currently customers are beginning to pay more attention to their unique requirements (such as high reliability, clean energy, and/or least cost), and this focus tends to highlight those requirements that are not easily met by the current grid design and operation. Superstorm Sandy and other natural disasters have, for example, focused attention on electric power interruptions that occur for many customers, resulting in threats to human health and safety in certain instances. Local generation tends to be the solution customers choose, but typically this is done without consideration for the impact on grid operation when scaled from hundreds to tens of thousands of distributed scale sources.

Similarly, the push to reduce power plant emissions has resulted in a significant increase in local clean generation (such as roof top solar photovoltaic systems), electrified transportation, and storage. By 2030, it is likely that local generation and the interaction with major and critical loads will drive operational strategies that are substantially different than current ones. The challenge will be to operate the grid with this diversity at the edge of the grid, incorporating complex economics with complex physical integration. Ancillary services will increasingly be met by controlling devices at the edge of the grid, thus creating challenges of synchronizing the operation of potentially millions of these devices.

Customers will be much more in the driver's seat in this future system with more options for how they react to the price of energy and services. Australia is already experiencing falling overall electricity demand at the same time the country is seeing higher peak demand. As the price of energy increases, customers are likely to make decisions that could drive this imbalance even higher.

Transactive energy is a term coined more than a decade ago to represent this complex interaction between the economics and physics at the edge of the grid. Grid operators in the Pacific Northwest in particular are developing this concept and experimenting with applying it in practice. It represents the type of concept that will be not only important but essential in the electrical grid of 2030.

Questions to Ponder

- What impacts will increasing consumer participation have on the operation of the grid? What new capabilities are needed?
- What will end-use customers who generate their own electricity (i.e., "prosumers") expect from the grid and the grid operator?

- How will the consumer role change from what it is today?
- How does this change the role of the grid operator?
- What new role does the distribution grid operator need to play versus the transmission grid operator?
- What new capabilities will be needed to perform this new role?
- How must current policies and/or regulations change to enable these new capabilities and roles?
- What are the financial implications of this transition?
- How will increasing energy prices impact the transition to distributed generation and storage?
- What are the risks of having the wrong pricing strategy?
- What are the implications for the future workforce – both inside the utilities and among third party providers?
- What data-sharing challenges can be foreseen?

SCENARIO 3: THE CHALLENGE OF HIGHER LOCAL RELIABILITY THROUGH MULTI-CUSTOMER MICROGRIDS

Description

Customers are becoming increasingly aware that the traditional "grid" electricity they have taken for granted is, in many cases, not meeting their needs. Whether customers want cleaner, more reliable, and better quality electricity or just "smarter" options, they are beginning to drive a new market for "non-grid" electricity technologies. These new customer-centric technologies are being developed and deployed at staggering rates and often without sufficient consideration for the impacts they might have on grid operations.

The design and operation of "local grids" – or as they are commonly called *microgrids* – is still evolving with dozens of "beta" versions being built around the country. These new systems can be under the control of a single customer or serve multiple customers, and they will typically utilize the utility grid infrastructure as part of the local microgrid that can be "islanded" as desired. These systems will become more and more sophisticated in the near future resulting in mature markets by 2020 and beyond. Additional information on microgrids is provided later in this report.

David Crane, CEO of NRG Inc., is one of the industry's most vocal advocates for the rapid move to distributed electricity generation resources and the disruptive impact they will have on the traditional grid. NRG is currently testing several Stirling engine-based combined heating and power (CHP) devices for residential application. NRG plans to have units commercially available for sale in late 2014.

Whether it's Stirling engines, rooftop solar photovoltaic modules, fuel cells, batteries, or something else, it is clear that microgrids will evolve to be a dominate force in the operation of the grid by 2030 and beyond. The challenge for grid operators will be to create the appropriate interfaces with these systems to allow optimal operation of the grid, the microgrid(s), and both together.

Questions to Ponder

- What are the implications of this new balancing requirement to the role of the grid and the grid operator?
- What exactly is the distribution operator's role versus the transmission operator's role?
- What new capabilities will be needed to perform these roles?
- What will the "owners" of a microgrid expect?
- What will the customers served by the microgrid expect?
- How will the increase in microgrids impact transmission planning?
- How must current policies and/or regulations change to enable these new capabilities and roles?
- What are the financial implications of this transition?
- What are the implications for the future workforce – both inside the utilities and among third party providers?
- How will planning occur for these microgrids? How will it impact the grid operator role?
- How will an increase in microgrids impact infrastructure investments?
- Will new rate structures be needed?

SCENARIO 4: THE CHALLENGE OF TRANSITIONING CENTRAL GENERATION TO CLEAN ENERGY SOURCES—LARGE-SCALE WIND, SOLAR, AND GAS

Description

Across the U.S. and around the globe, we are seeing a transition of central generation from traditional fuel sources to cleaner fuel sources. This transition is being driven by policies, regulations, economics, and public sentiment. Various incentives and increasing market demand have driven down the price for wind and solar, while new policies and regulations are driving up the price of coal, oil, and nuclear. Technological advances have resulted in cheaper natural gas here in the U.S. Together, these conditions are driving a transition in the U.S. large-scale generation mix. This transition is also introducing new challenges and opportunities, bringing new participants into the market, and introducing new operating characteristics for the generation fleet.

This changing large-scale generation mix also brings increasing variability that the grid must accommodate and manage. This variability is resulting in having excess power at times as well as competing priorities for when the various generators should or must operate. In the Pacific Northwest, the combination of hydroelectric and wind generation has introduced the need to balance these competing priorities. To leverage fully these available resources, the grid operators must consider new ways to manage the load side of the energy value chain equation. At the same time, customers are taking more control of their energy usage. Many are lowering their overall demand for electricity through energy efficiency and changing behaviors, or by installing rooftop solar photovoltaic installations, buying smart appliances, and signing up for other new third-party services that can help them better manage their electricity usage.

These dynamics are changing the role of the grid and the grid operator going forward. They are also challenging traditional planning processes. In an industry where assets traditionally have a 30 year or greater life span, these changes could result in overbuilding some asset capacity and underbuilding others.

Questions to Ponder

- Will these shifts to different generation fuels result in an increased regional approach to siting and leveraging future generation, and if so, what are the implications to the grid?
- What capabilities will be required of the grid to fully leverage non-dispatchable large generation sources such as wind?
- How does this change the role of the distribution grid and transmission grid operators?
- What role does the distribution grid operator need to play versus the transmission grid operator?
- How must current policies and/or regulations change to enable these new capabilities and roles?
- What are the financial implications of this transition?
- What are the implications for the future workforce – both inside the utilities and among third party providers?
- What are the new tools/models/information needed to handle this transition?

SCENARIO 5: THE CHALLENGE OF PLANNING FOR EMPOWERED CUSTOMERS

Description

In the past, for the majority of residential and small commercial electric customers, there has been little or no choice in how they met their electric power needs. The electric utility industry has been a commodity business where, much like the days when Henry Ford made his famous statement: "people can have the Model T in any color – so long as it's black," electric customers were at the mercy of their power company. The industry mindset can even be seen in the fact that it has referred to them as "ratepayers" not "customers". In the future, grid owners and operators must change this mindset and gain a better understanding of customers' needs, desires, and ultimately their choices.

Technological innovations, new market structures, and changing customer expectations are shifting this long-held view of end users of electricity. Customers are now becoming empowered. Smart meters, distributed-scale generation options, smart appliances, home energy management systems, electric vehicles, and battery storage are some of the technological advances that are driving this paradigm shift with respect to electric customer choice. And customers are much more informed about what is possible – social media is expanding their "neighborhood" to allow them to compare experiences and options with others across the country and around the globe.

Policies are also playing a part in this evolution. Examples of such policies include net metering rules that allow customers to get full retail credit for any power they produce from renewable sources and retail deregulations where new energy service providers can offer innovative rates.

Prices are also having a significant impact on the choices customers make. As electricity prices rise and distributed generation costs decline, customers are looking at alternatives and options. It is now economically viable for customers in some areas to use rooftop solar photovoltaic arrays to offset the energy they purchase from their provider. Increasingly, energy efficiency also is seen as a good investment. Education is also starting to result in behavior changes that reduce energy demand.

Looking out toward 2030, it is not hard to imagine that electric customers will have a profound impact on the energy value chain and how it should be built and operated. As we look at the role of the future electric grid and the grid operator, consider the questions listed below.

Questions to Ponder

- How could this new dynamic of increasing customer expectations and choices impact the distribution grid?
- How could this new dynamic impact the transmission grid?
- How should grid operators plan for this new dynamic of customer empowerment and their associated increasing expectations?
- Will customer-owned battery storage be the killer application that directly competes against grid services?
- What are the financial implications for funding grid investments and on-going operations?
- How will market structures need to change?

- How should we plan for those customers that cannot or simply choose not to generate their own electricity to ensure their cost for electricity stays reasonable?
- Does this increased engagement and empowerment of customers impact the relationship between transmission and distribution?
- What new capabilities will grid operators and the grid need in order to meet these new expectations?
- What new tools/models/information will grid operators need?
- How do current policies and regulation have to change to enable this new capability and role?
- What are the implications for the future workforce – both inside the utilities and third party providers?
- How will market structures need to evolve to handle new players?

SOUTHEAST REGION CONDITIONS

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This Southeast Region Workshop is focused on the future of the grid in the Southeastern part of the U.S., specifically in the States of Alabama, Arkansas, Florida, Georgia, Kentucky, Louisiana, Mississippi, Missouri, North Carolina, South Carolina and Tennessee. These 11 states are shaded in green Figure 1.

Figure 1. States Included in the Southeast Region Workshop

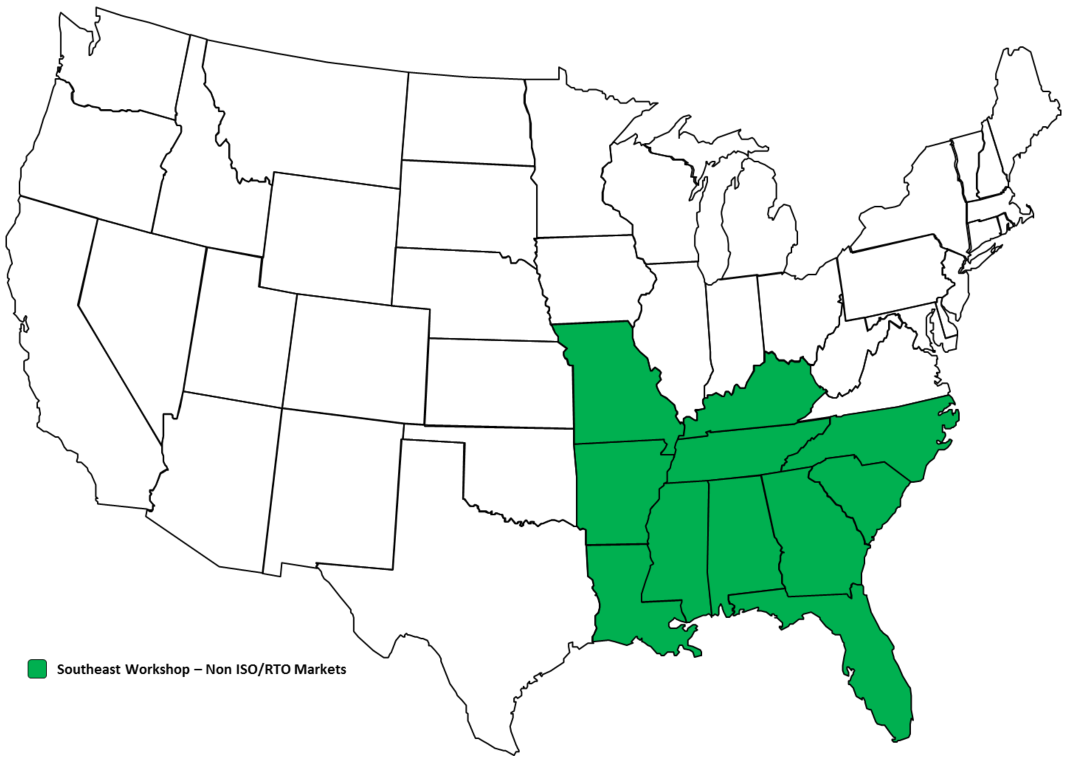
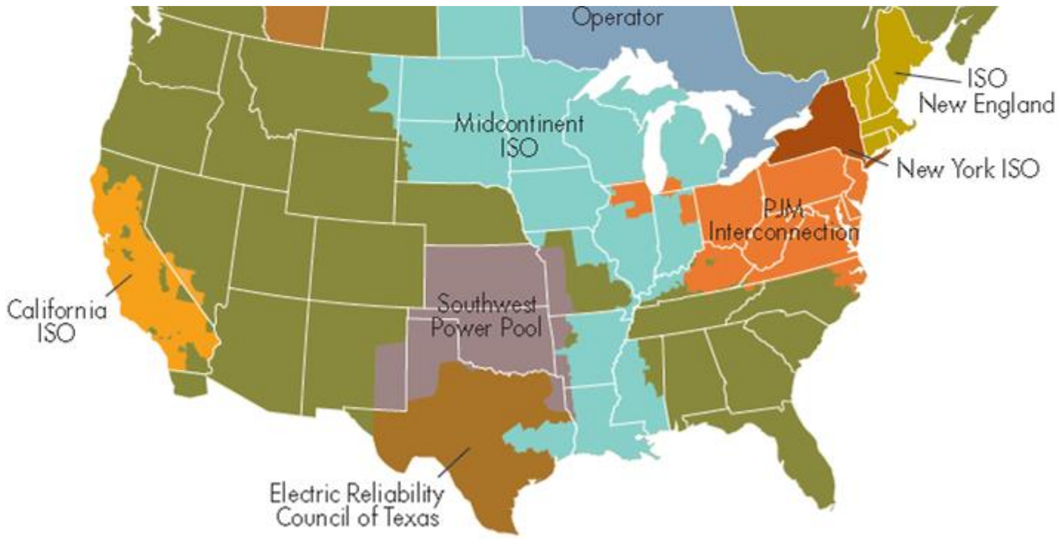


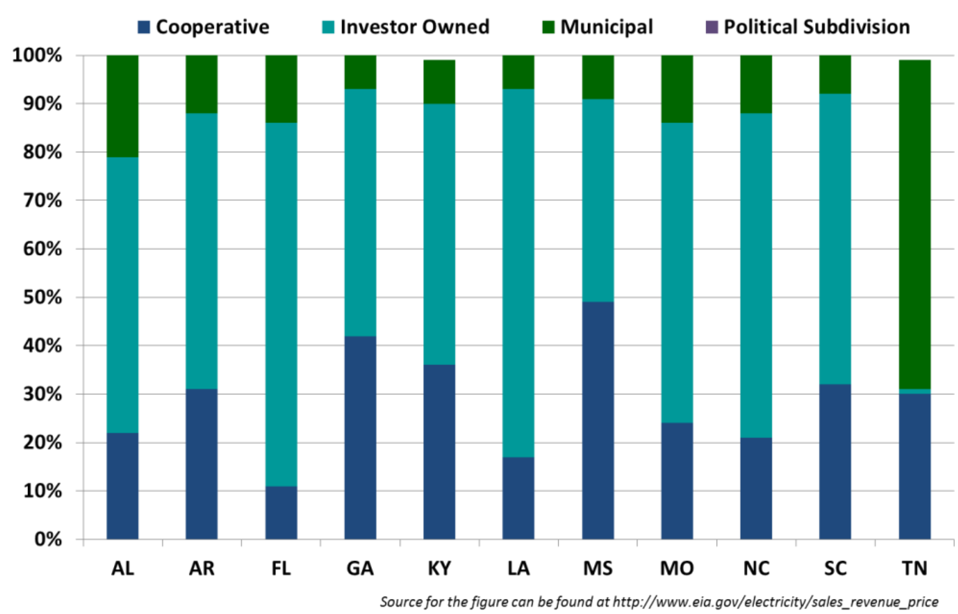
Figure 2 shows a map of the Independent System Operators (ISOs) operating areas in the contiguous United States and parts of Canada. As Figure 2 reveals, ISOs are prevalent only in the western part of the Southeast Region. Midcontinent ISO (MISO) operates in five of this region's states, specifically Alabama, Arkansas, and parts of Kentucky, Louisiana, and Missouri. Southwest Power Pool (SPP) operates in parts of Arkansas, Louisiana, and Missouri. PJM Interconnection operates in the eastern part of Kentucky and North Carolina. There are no ISOs operating in the other states in this region. The Southeast Region is made up of vertically-integrated utilities (VIUs) that are responsible for everything from generation to transmission to distribution.

Figure 2. ISO RTO Operating Regions [1]



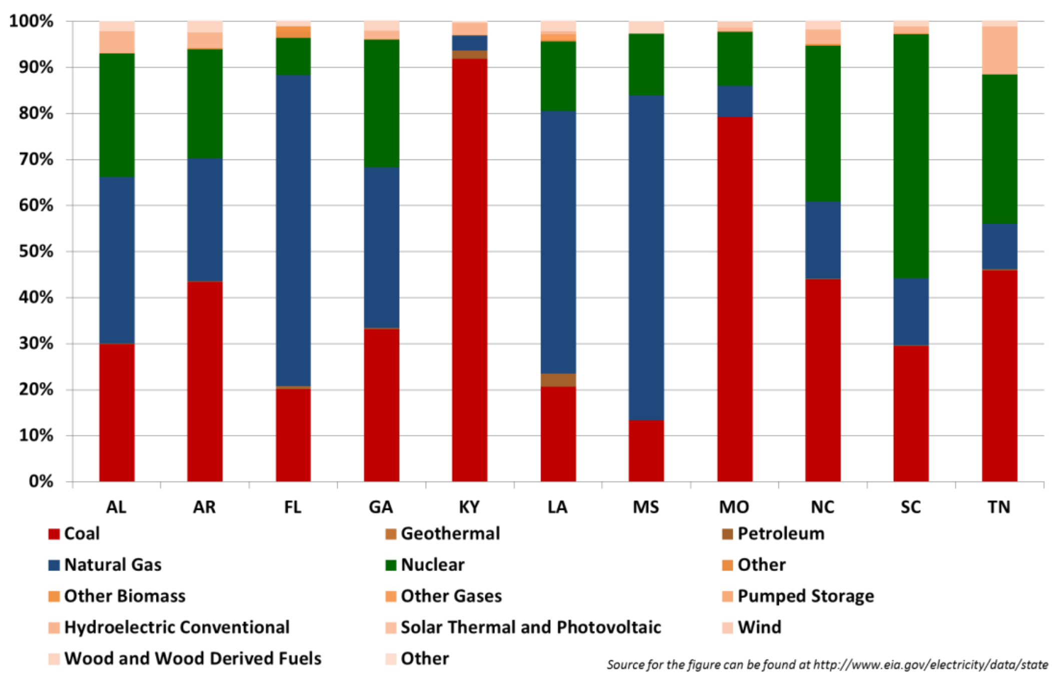
The utility profiles of each state in this Workshop were investigated and the results are shown in Figure 3. Investor-owned utilities (IOUs) are common in most states in this region followed by electric cooperatives. There are a few states that differ from the norm. For example, in Tennessee municipally-owned utilities account for 68 percent of that state's utility profile and there are few IOUs. With 49 percent of the State's utility profile consisting of cooperatives, Mississippi has the largest percentage of cooperatives of the States in this region [2].

Figure 3. State Utility Profiles



The generation mix of each state in this region was investigated and the results are shown in Figure 4. Coal (shown in red), natural gas (shown in blue) and nuclear (shown in green) are all prevalent in this region. Based on megawatt-hours (MWh) coal is used for 92 percent of the generation in Kentucky, 79 percent of the generation in Missouri and over 40 percent of the generation in Arkansas, North Carolina and Tennessee. Nuclear accounts for 53 percent of South Carolina's power generation mix and over 30 percent in North Carolina and Tennessee. Mississippi relies on natural gas for 71 percent of its power generation, while in Florida and Louisiana natural gas represents 68 and 57 percent, respectively [2]. There is wind generation in Tennessee and Missouri, but it accounts for about 1 percent of generation in each state and the remaining Southeast Region states have no significant land-based wind generation.

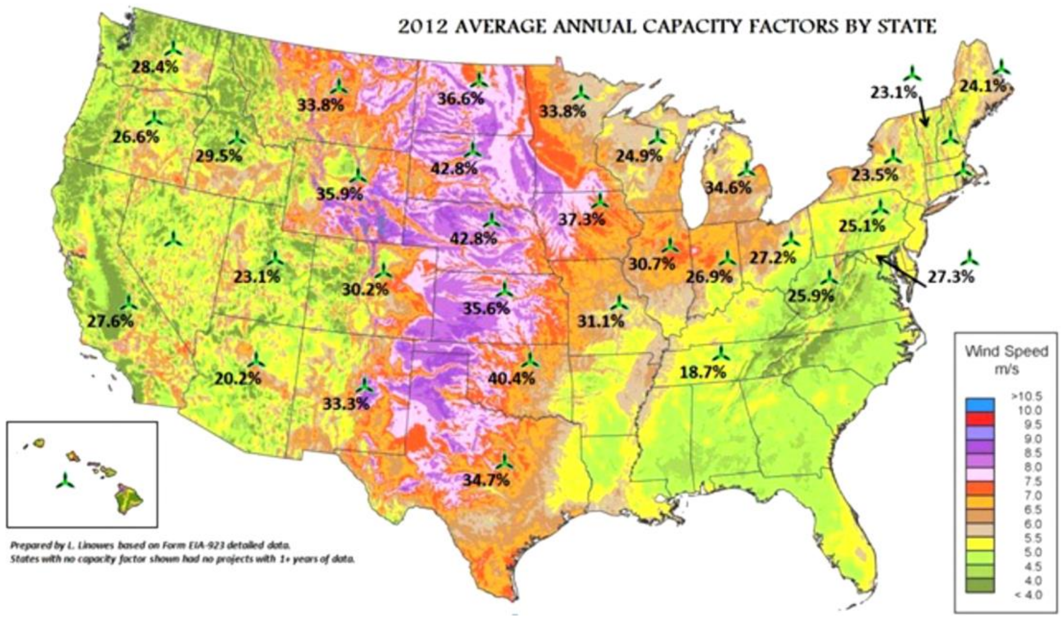
Figure 4. State Generation Based on MWh



POTENTIAL FOR WIND POWER

Figure 5 shows the Central Region of the United States has high wind resources and high capacity factors for wind power. With the capacity factors for wind power in the Southeast Region lower than in neighboring regions, transmission of wind power into the Southeast seems plausible. However, there are no widely-accepted plans to build large-scale transmission lines to bring wind power from the Central Region to the Southeast Region. One reason may be the addition of new nuclear plants in Georgia and South Carolina and the absence of RPS standards in this region make wind power less competitive in this region. From an economic perspective, the U.S. Energy Information Administration (EIA) data indicates retail electricity prices ranging from ~$0.07/kWh to $0.106/kWh for the Southeast Region states, which is below the U.S. average of ~$0.106/kWh [3] making wind imports a non-starter.

Figure 5. Capacity Factors of Wind Power [4]



STATE RENEWABLE ENERGY AND ENERGY EFFICIENCY STANDARDS

In this region, only the States of North Carolina and Missouri have a renewable portfolio standard (RPS). North Carolina's goal is 12.5 percent by 2021 for IOUs and 10 percent by 2018 for cooperatives and munis. Missouri's goal is 15 percent by 2021 [5].

Arkansas, Florida and Missouri each have energy efficiency resource goals whereas the other states in this region have neither a goal nor standard for energy efficiency. Arkansas' goal is listed as a reduction of 0.75 percent of 2010 electric sales reduction by 2013 and 0.4 percent of 2010 gas sales reduction by 2013. Florida's goal is based on normal, summer peak, and winter peak demands. Florida is striving to obtain 7,842 Gigawatt-hours (GWh) cumulative reductions from 2010-2019 (statewide goal); 3,024 MW cumulative summer peak demand reduction from 2010-2019; and 1,937 MW cumulative winter peak demand reduction from 2010-2019 (statewide goal). Missouri has a goal of 9.9 percent cumulative electricity savings by 2020 and an additional 1.9 percent each year thereafter [5].

NET METERING POLICIES

Net metering allows for the flow of electricity both to and from the customer. Net metering is required by law in most U.S. States, but state policies vary widely. For electric customers who generate their own electricity and their generation exceeds their usage, electricity flows back to the grid, offsetting electricity purchased and consumed at different times during the same billing cycle. Seven states, Arkansas, Louisiana, Florida, Georgia, Kentucky, Missouri and North Carolina have net metering policies in place. In Arkansas and North Carolina these policies apply to IOUs. South Carolina has a voluntary utility program on net metering. Alabama, Mississippi and Tennessee have no net metering policies [5].

NORTH CAROLINA'S ENERGY GENERATION SHIFT

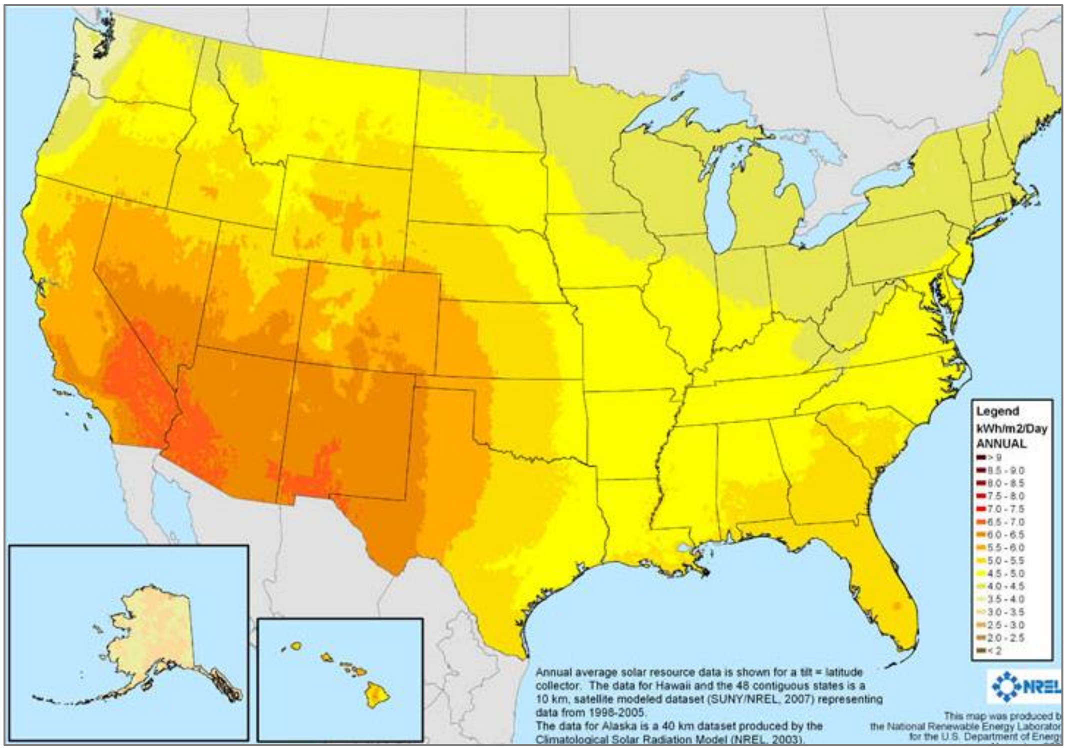
North Carolina has three operating nuclear power plants with a total of five reactors. Currently no plans exist to shut down these plants, and most have been granted license extensions for the next 30 to 40 years [6]. In the case of coal, Duke Energy currently has seven operational coal-fired power plants – the majority of which have been retrofitted with emissions controls or have undergone full modernization processes [7].

Between 2011 and 2013, Duke Energy retired nine coal-fired plants in North Carolina, all of which are now in various stages of decommissioning [8]. While a retired plant eliminates air pollutants there can be other hazards with these plants. On February 2, 2014 at the retired Dan River Steam Station in Eden, N.C. a break in a stormwater pipe beneath an ash basin caused an estimated 30,000 to 39,000 tons of ash to be released into the Dan River [9]. While the incident was reported and mitigation steps are underway, the incident is a reminder of the potential hazards associated with these facilities. The decommissioning of the nine coal-fired plants resulted in a 771 MW decrease in generation capacity for Duke Energy. However, this was recovered and exceeded by the retrofitting process as well as the addition of five natural gas-fired plants totaling 3,869 MW of additional capacity [10]. As North Carolina's largest utility, Duke Energy serves as a case study for the changing profile of the state's power generation makeup.

SOLAR ENERGY POTENTIAL

While not as sunny as the Southwestern U.S., the Southeastern U.S. enjoys more sunshine than other parts of the country. Figure 6 is a map from the National Renewable Energy Laboratory (NREL) showing annual average amounts of sunlight available for a solar photovoltaic (PV) system on a daily basis [11]. The units are in kWh per square meter per day. The information is based on 1998 to 2005 data at a resolution of 10 kilometers by 10 kilometers.

Figure 6. Solar Photovoltaic Daily Resources[1] [11]



According to the Solar Energy Industries Association (SEIA), five states in the Southeast Region increased their solar energy generation in 2013. In four of the states, the 2013 installed capacity represents greater than 50 percent growth in capacity in a single year. North Carolina and Georgia were among the top 10 states in installed solar capacity [12]. North Carolina ranked 3rd in 2013 with 335 MW of solar electric capacity installed that year bringing its total installed capacity to 557 MW [13]. At that capacity, North Carolina ranks 4th in the U.S. for total installed capacity behind California (5,660 MW), Arizona (1,822 MW), and New Jersey (1,211 MW) [12]. Florida is ranked 3rd in solar potential however only 26 MW of solar electric capacity were installed in 2013 bringing its total installed capacity to 213 MW of solar energy. Florida lacks a RPS and prohibits power purchase agreements, both policies that in other states have promoted solar investments [14]. Table 1 shows 2013 solar installation capacity, 2013 ranking and the state's total solar capacity for the 11 states in the Southeast Region as reported by SEIA.

[1] Based on 1998 – 2005 Data for Flat Plate Tilted South at Latitude

Table 1. Solar Capacity within the Southeast Region[2] [12]

State	National 2013 Ranking	2013 Installed Solar Electric Capacity	Total Installed Solar Electric Capacity	1 – year Capacity Growth
Alabama	n/a	n/a	n/a	n/a
Arkansas	n/a	n/a	n/a	n/a
Florida	18	26 MW	213 MW	14 %
Georgia	7	91 MW	116 MW	364 %
Kentucky	n/a	n/a	n/a	n/a
Louisiana	n/a	n/a	n/a	n/a
Mississippi	n/a	n/a	n/a	n/a
Missouri	17	28 MW	39 MW	254 %
North Carolina	3	335 MW	557 MW	150 %
South Carolina	n/a	n/a	n/a	n/a
Tennessee	19	25 MW	74 MW	51 %

Nationally solar installations increased 41 percent over 2012 with 792 MW in the residential sector, 1,112 MW in the non-residential sector, and 2,847 MW in the utility sector [15]. In Georgia and North Carolina, the majority of the growth is in the utility sector whereas the residential sector accounted for most of the 2013 installed solar capacity in Florida and Tennessee [15]. SEIA projects a 26 percent growth in solar installation in 2014 with residential sector growth being the most rapid [15].

DEMAND RESPONSE INITIATIVES IN FLORIDA

In Florida, the state's largest utility company, Florida Power and Light Company (FPL), has both residential and commercial demand response programs. For its commercial customers, FPL offers a Commercial Demand Reduction program, whereby a load management device is installed at the facility which automatically reduces the load at predetermined load control events [16]. The residential program functions on a per-appliance basis, where FPL remotely switches specific equipment on and off such as water heaters, central heating and cooling units, and pool pumps (a common target for demand response, unique to Florida due to the prevalence of home pools). This typically occurs in the summer, at off-peak hours in the early to late afternoons. Approximately 780,000 customers are enrolled in this program [17]. The system consists of 900,000 load control devices with a load control capacity of 984 MW. It has been estimated that the program has helped defer the construction of three new power plants [18].

Other Florida utilities employ similar programs. Gulf Power has had a demand response program in place since 1998, and has over 10,000 customers as of October 2012 [19]. The Tampa Electric Company offers a dynamic pricing plan which breaks pricing into four categories based on demand (low, medium, high, and critical). The program has succeeded in reducing the utility's per customer load by 3.1 kW in

[2] SEIA data is for 30 individual states and Washington D.C.

winter and 2.0 kW during the summer, and enrolled 2,000 residential customers out of Tampa Electric's 687,000 residential, commercial and industrial customers [20].

POWER PLANT WATER NEEDS

Electric power generation is one of the largest consumers of water in the U.S., accounting for 49 percent of the total water use [21]. According to the U.S. Geological Survey (USGS), about 201,000 million gallons of water were used each day in 2005 to produce electricity (excluding hydroelectric power) [21]. The amount of water consumed depends on the type of power plant, of course. According to the Nuclear Energy Institute,

> "Nuclear energy consumes 400 gallons/MWh with once-through cooling and 720 gallons/MWh with wet cooling towers. Coal consumes less, ranging from about 300 gallons/MWh for plants with minimal pollution controls and once-through cooling to 714 gallons/MWh for plants with advanced pollution control system and wet cooling towers. Natural gas-fueled power plants consume even less, at 100 gallons/MWh for once-through, 370 gallons/MWh for combined-cycle plants with cooling towers and none for dry cooling" [22].

Coal, natural gas, and nuclear power plants are prevalent in the Southeast Region. Table 2 shows water consumption in the Year 2000 for the 10 states in the Southeast Region for the purpose of thermoelectric power. The cumulative fresh water amount used for electric production purposes for this region is approximately 46,110 million gallons per day, representing about one-third of the total fresh water withdrawals for thermoelectric power across the U.S. in 2000 [23]. Based on this data, the Southeast Region is highly dependent on an abundant supply of water for electricity generation.

Table 2. Estimated Use of Water for Thermoelectric Power in the U.S. in 2000 [23]

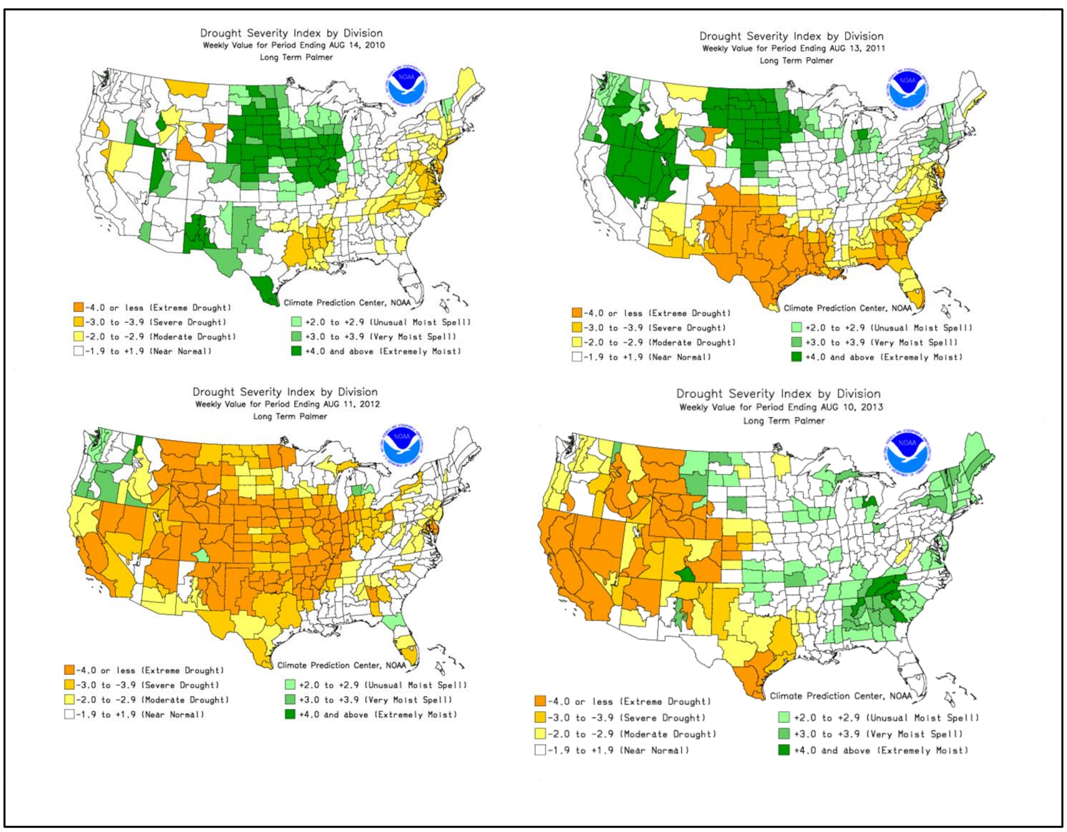
	Water withdrawals in 2000 for Thermoelectric Power (in million gallons per day)[3]		
State	**Fresh**	**Saline**	**Total**
Alabama	8,190	0	8,190
Arkansas	2,180	0	2,180
Florida	658	12,000	12,600
Georgia	3,250	62	3,310
Kentucky	3,260	0	3,260
Louisiana	5,610	0	5,610
Mississippi	362	148	510
North Carolina	7,850	1,620	9,470
South Carolina	5,710	0	5,710
Tennessee	9,040	0	9,040
Totals	**46,110**	**13,830**	**59,880**

[3] USGS website notes that figures may not sum to totals because of independent rounding.

REGIONAL DROUGHT IMPLICATIONS

Drought conditions can affect water availability for at power production, depending on the system. Open cycle cooling systems that draw fresh water from lakes and rivers are especially susceptible. Higher water temperatures can lead to inefficient cooling, and exposed water intake structures can render plants non-operational [24]. Drought conditions vary by region and year. Yet, many areas across the U.S. have experienced record drought levels in recent years, as has been widely reported in the press. The Palmer Drought Severity Index (PDSI) provides an index of relative dryness for water sensitive industries. National Oceanic and Atmospheric Administration (NOAA) provides the PDSI on a weekly basis for the continental U.S. The PDSI maps for 2010 – 2013 during the second week in August, typically a hot summer month when electricity demand is high are displayed in Figure 7. Extreme drought conditions are indicated in orange, lesser drought conditions in yellow and higher than normal moisture in green. In August 2012 the Browns Ferry Nuclear Plant in Alabama was forced to shut down for a total of eight days due to drought conditions and increasing water temperatures in the Tennessee River which is the plant's source of cooling water [25]. While a reliability report by the North American Electric Reliability Corporation (NERC) did not forecast any issues for the summer of 2012 in the Southeast, it did note lower water levels as a potential source for concern that will need to be addressed in the future [26].

Figure 7. Drought Severity Index for second week in August 2010 – 2013 [27]



LANDSCAPE OF THE INDUSTRY

LANDSCAPE OF THE INDUSTRY

Almost everything written about the electric power industry these days refers to change: Changing customer demands, changing policies, changing technologies, and even changing business models. Such a dynamic landscape is difficult to characterize and impossible to capture in this brief document. Nevertheless, this section attempts to provide key highlights that indicate the direction, speed, and magnitude of the changes that will influence the nature of grid operations in 2030 and beyond. The information provided here is not new, but is based on the most important and readily-available documents.

In the North American Electric Reliability Corporation (NERC) *2012 Long-Term Reliability Assessment* published earlier this year [28], it identified broad issues that are impacting the industry and its ability to maintain the reliability of the bulk power system at mandated levels. These findings which are shown in Appendix A represent a comprehensive look at grid reliability and do not necessarily reflect specific regional or local issues. While they do address a ten year view of the industry, they do not necessarily capture the organic innovation taking place both in the utility industry and among customers.

POLICY TRENDS

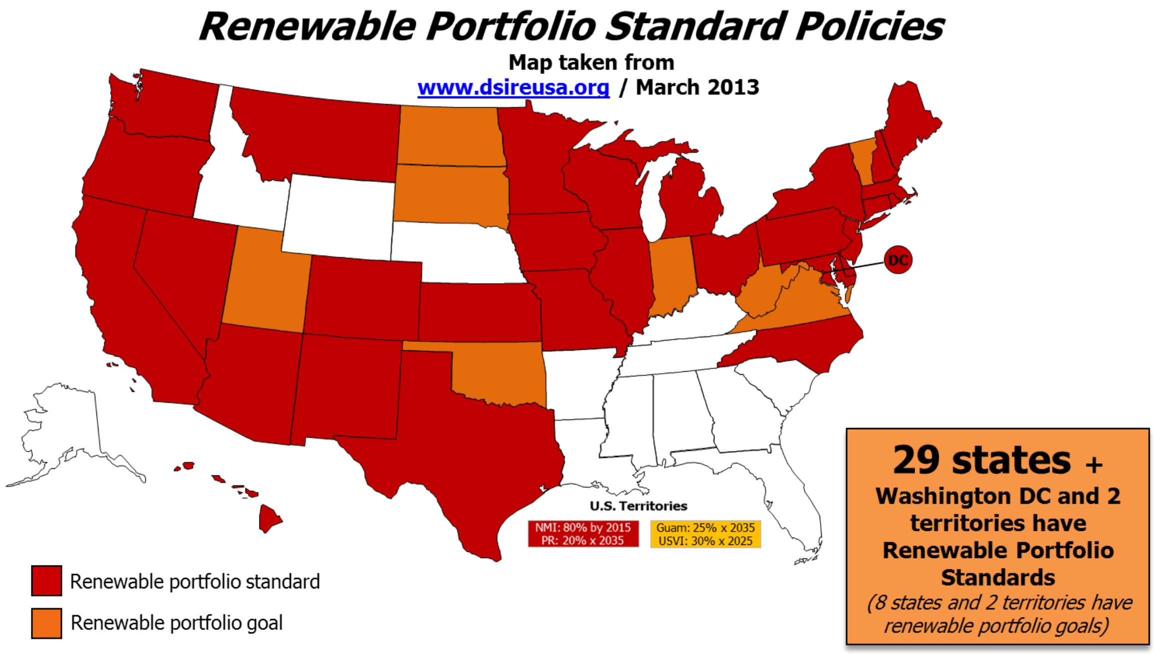
Federal, state, and local policies are all affecting the changes involving the grid and vice versa. This section highlights some of the most important policy developments and trends. While the shifting U.S. political landscape could affect the speed of policy change, it is unlikely to alter significantly the fundamental direction.

Renewable Portfolio Standards

A Renewable Portfolio Standard (RPS) sets a minimum requirement for the share of electricity to be supplied from designated renewable energy resources by a certain date/year. As one would expect, states with RPSs have experienced an increase in the amount of electricity generated from eligible renewable resources. Figure 8 shows the U.S. States as of March 2013 that have implemented RPSs. The map is from the Database of State Incentives for Renewables & Efficiency (DSIRE) Data Base that is currently operated by the North Carolina Solar Center with support from the Interstate Renewable Energy Council (IREC) and funded by DOE. Figure 8 also shows the eight U.S. States that have implemented renewable energy goals.

RPSs vary widely in terms of program structure, enforcement mechanisms, size, and application, but they all have some common features. Another feature several states use to meet these requirements is a Renewable Electricity Credit (REC) trading system structured to minimize the costs of compliance [5].

Figure 8. States with Renewable Portfolio Standards [5]



DSIRE has summary maps similar to the one shown in Figure 8 for various financial incentives and other policies that promote renewable energy in the U.S. The data from some of those maps are summarized in Table 3. The right column lists the financial incentive or policy. In the next three columns their adoption levels across the U.S. are summarized [5].

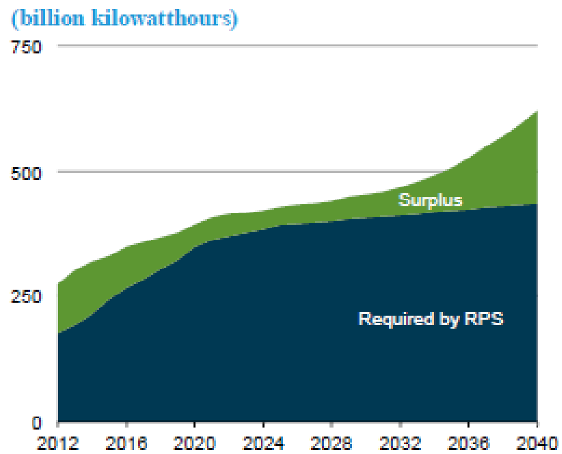
Table 3. U.S. Adoption of Incentives and Other Policies That Promote Renewable Energy [5]

Financial Incentive or Regulatory Policy	# of States	D.C.	# of Territories
3rd Party Solar Purchase Power Agreement (PPA) Policies	At least 22	Yes	1
Grant Programs for Renewables	22	No	2
Interconnection Policies	43	Yes	1
Loan Program for Renewables	41	No	0
Net Metering Policies	43	Yes	4
Property Assessed Clean Energy (PACE) Financing Policies	29	Yes	0
Property Tax Incentives for Renewables	38	Yes	1
Public Benefits Funds for Renewables	15	Yes	1
Rebate Programs for Renewables	16	Yes	2
Sales Tax Incentives for Renewables	28	No	1
Tax Credits for Renewables	24	No	0

EIA's *Annual Energy Outlook 2013* (AEO2013) released in April 2013 models the aggregate RPS requirement for the various state programs in what is called the Reference Case. The Reference Case model takes into account the impacts of state laws requiring the addition of renewable energy generation or capacity by utilities doing business in the states. The results are shown in Figure 9. It shows that states in general are projected to meet their ultimate RPS targets. As stated in AEO2013: "most states are meeting or exceeding their required levels of renewable generation based on qualified generation" [29]. This is partially due to the industry having a strong impetus to act prior to repeated temporary expirations and eventual predicted sunsets of Federal renewable energy incentives.

Most RPS targets are tied to retail electricity sales. With relatively slow growth in electricity sales throughout most of the country, the renewable generation entering service recently has gone farther toward meeting proportionally lower targets for absolute amounts of energy (that is, for kWh of energy, as opposed to energy as a percentage of sales) [29].

Figure 9. Total Renewable Generation Required for Combined State Renewable Portfolio Standards and Projected Total Achieved, 2012-2040 [29]

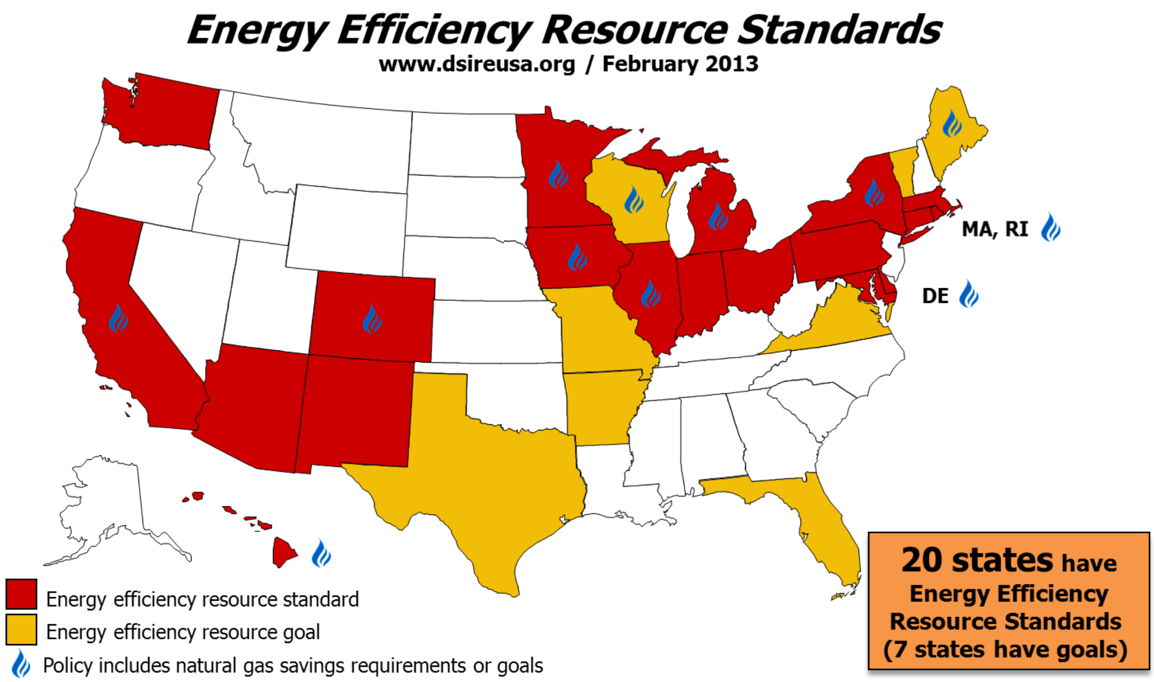


Based on the adoption rate of RPSs, the majority of the country is driving toward a minimum share of electricity to be supplied from renewable energy even without a national-level RPS program. The projection in Figure 9 shows that the amount of renewable generation being produced is greater than the amounts required by most or all states' RPSs, as indicated in the green area in the chart above. The grid will need to accommodate this additional renewable energy; therefore, it will be necessary to forecast the generation from these resources and communicate with them along the different points of the grid.

Energy Efficiency Resource Standards

Energy efficiency resource standards (EERSs) require utilities to meet specific targets for energy savings from energy efficiency measures. An EERS is sometimes coupled with a state's RPS policy and is included as a "lower-tier" resource [30]. Figure 10 shows the U.S. States as of February 2013 that have implemented EERSs.

Figure 10. States with Energy Efficiency Resource Standards [5]

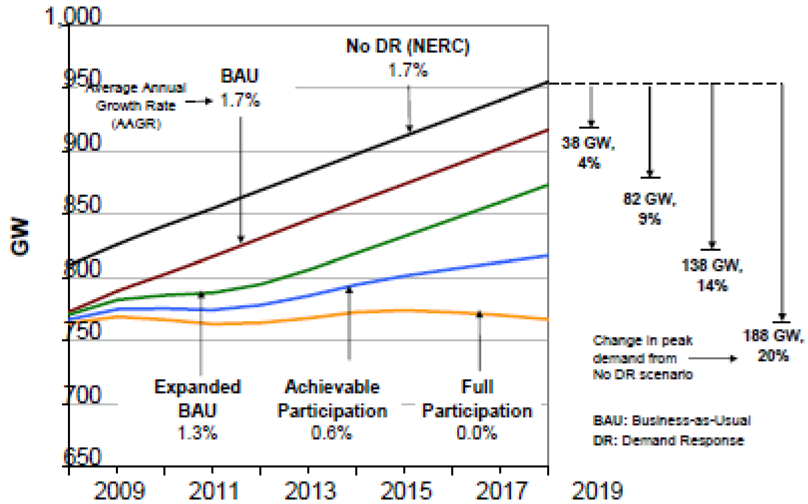


Demand Response Policies

Demand response encompasses a range of incentive mechanisms aimed at reducing customers' demand for electricity. These mechanisms typically consist of incentive payments, dynamic pricing plans, and other strategies used to change the consumption patterns of end-users. Although generally aimed at reducing loads at times of peak demand, demand response can include actions that change any part of a utility's load profile.

A 2009 Federal Energy Regulatory Commission (FERC) study of demand response potential predicted varying levels of reduction in peak demand based on a number of different scenarios [31]. Figure 11 shows different peak demand forecasts under the various scenarios presented in the FERC study projected running through 2018.

Figure 11. U.S. Peak Demand Forecast by Scenario [31]



If existing demand response policies were to continue, shown on the graph in Figure 11 as the "Business-as-Usual (BAU)" scenario, the U.S. could expect to see a reduction of 38 GW, or 4 percent in peak demand from the base case by 2019. By contrast, assuming a nationwide adoption of demand response programs where dynamic pricing is the norm, this model indicates a 188 GW, or 20 percent reduction in peak demand by 2019. This would not only keep pace with the annual growth rate, but it would also reduce the peak load from its starting point in 2009. This shows that effective demand response policies can have significant impacts on the nation's energy consumption and prices as well as saving utilities and customers substantial amounts of money.

Demand response is being encouraged by FERC through its National Action Plan on Demand Response [32], by Pacific Gas & Electric's InterAct tool, and by a host of other national, state, and local actions. Legislative plans have been set in motion in several states that put forth goals for reduction of peak demand. For example, the Michigan Public Service Commission's *Michigan's 21st Century Energy Plan* released in 2007 and the State of New Jersey's Board of Public Utilities' *2011 Energy Master Plan* both call on utilities to employ demand response practices [33] [34]. In 2009, legislation was passed in both Maryland and Colorado that set goals for energy consumption and peak demand reduction with the latter allowing cooperatively-owned utilities to set inclining block rates for residential customers [32]. This means that the more energy a household uses, the higher is the per kilowatt hour cost it faces, thus incentivizing households to reduce their consumption. These actions help lower the overall demand for electricity, which in turn may help counter the need for upgrades to transmission and distribution infrastructure due to additional loads entering into the grid.

Oftentimes states' demand response actions are implemented through retail programs, some of which may not require new enabling technologies such as smart meters. This was the case in Arizona, where its two major utilities offered time-of-use (TOU) pricing that attracted 30 to 40 percent of the residential market without requiring in most cases new equipment to be installed.

California has had demand response regulations in place for a number of years including TOU pricing since 1978. These policies have contributed to the fact that the state's energy usage has remained constant for 30 years despite the overall increase for the U.S. as a whole [32]. In addition, California's Energy Action Plan has gained recognition for deploying advanced metering initiatives and dynamic pricing. In what was the country's first dynamic pricing pilot, California adjusted rates for 2,500 customers to reflect the changing demand and account for peak loads. The program was considered a success, as it provided valuable data about customers' willingness to participate in a demand response program, and many customers elected to keep the experimental pricing scheme.

Environmental Requirements

Anticipated environmental regulations are an important topic within the industry today. Current uncertainty and future regulations could have a significant impact on the future generation mix.

The U.S. Environmental Protection Agency (EPA) is authorized under Section 111 of the Clean Air Act to "develop regulations for categories of sources which cause or significantly contribute to air pollution which may endanger public health or welfare" [35]. As part of the Climate Action Plan, a Presidential Memorandum in June 2013 directed the EPA to issue proposed standards, regulations, or guidelines to address carbon pollution from modified, reconstructed and existing power plants by June 2014 and to provide a revised proposal for carbon pollution standards for future power plants by September 2013 [36]. The timeline for these and other actions set by the President is shown in Table 4.

Table 4. Timeline for Carbon Pollution Standards [36]

Activity	Deadline
Issue a new proposal for carbon pollution standards for future power plants	September 20, 2013
Issue proposed carbon pollution standards, regulations, or guidelines, as appropriate, for modified, reconstructed, and existing power plants	June 1, 2014
Issue final standards, regulations, or guidelines, as appropriate, for modified, reconstructed, and existing power plants	June 1, 2015
States submission of implementation plans to EPA	June 1, 2016

In September 2013, EPA began proposing standards for reductions in carbon emissions from new plants. The proposal has since been revised and is in the public comment stage as of January 2014. The current action proposes an emission limit of 1,100 pounds carbon dioxide (CO_2) per MWh for coal-fired power plants using integrated gasification combined cycle (IGCC) technology [37]. For efficient natural gas combined-cycle (NGCC) plants, proposed emission limits are 1,000 lbs CO_2/MWh for larger units and 1,100 lbs CO_2/MWh for smaller units [37].

Currently, there are no proposed EPA emissions standards for CO_2 in existing power plants. There are Federal guidelines developed by EPA which are used by individual states to facilitate in the formation of their own emissions reduction plans. States have a significant amount of flexibility and autonomy when setting their standards, although these plans are subject to review by EPA [38].

In addition to carbon pollution standards, there are Mercury and Air Toxics Standards (MATS), enacted in 2011, that require power plants to limit their emissions of toxic air pollutants such as mercury and arsenic. These standards apply to all hazardous air pollutants (HAPs) emitted by coal-fired and oil-fired electrical generating units (EGUs) with a capacity of 25 MW or greater [39]. Existing sources of air pollution have four years (since the final rule publishing in 2012) to comply with MATS, and EPA estimates that this should be sufficient time for most, if not all, sources to come into compliance [39].

On March 28, 2013, EPA finalized updates to emission standards for new power plants as shown in Table 5. Included in these standards are limits for particulate matter, mercury, sulfur dioxide (SO_2), and other pollutants, such as heavy metals and acidic gases [40]. According to EPA, there are approximately 1,100 existing coal-fired units and 300 oil-fired units affected by the MATS [41].

Table 5. Emissions Standards for New EGUs [42]

TABLE 1—REVISED EMISSION LIMITATIONS FOR NEW EGUs

Subcategory	Filterable particulate matter, lb/MWh	Hydrogen chloride, lb/MWh	Mercury, lb/GWh
New—Unit not designed for low rank virgin coal	9.0E–2	1.0E–2 [a]	3.0E–3.
New—Unit designed for low rank virgin coal	9.0E–2	1.0E–2 [a]	NR.
New—IGCC	7.0E–2 [b] 9.0E–2 [c]	2.0E–3	3.0E–3.
New—Solid oil-derived	3.0E–2	NR	NR.
New—Liquid oil—continental	3.0E–1	NR	NR.

Note: lb/MWh = pounds pollutant per megawatt-hour electric output (gross).
lb/GWh = pounds pollutant per gigawatt-hour electric output (gross).
NR = limit not opened for reconsideration (77 FR 9304; February 16, 2012).
[a] Beyond-the-floor value.
[b] Duct burners on syngas; based on permit levels in comments received.
[c] Duct burners on natural gas; based on permit levels in comments received.

TABLE 2—REVISED ALTERNATE EMISSION LIMITATIONS FOR NEW EGUs

Subcategory/pollutant	Coal-fired EGUs	IGCC [a]	Solid oil-derived
SO_2	1.0 lb/MWh	4.0E–1 lb/MWh [b]	1.0 lb/MWh
Total non-mercury metals	NR	4.0E–1 lb/GWh	NR
Antimony, Sb	NR	2.0E–2 lb/GWh	NR
Arsenic, As	NR	2.0E–2 lb/GWh	NR
Beryllium, Be	NR	1.0E–3 lb/GWh	NR
Cadmium, Cd	NR	2.0E–3 lb/GWh	NR
Chromium, Cr	NR	4.0E–2 lb/GWh	NR
Cobalt, Co	NR	4.0E–3 lb/GWh	NR
Lead, Pb	2.0E–2 lb/GWh	9.0E–3 lb/GWh	NR
Mercury, Hg	NA	NA	NR
Manganese, Mn	NR	2.0E–2 lb/GWh	NR
Nickel, Ni	NR	7.0E–2 lb/GWh	NR
Selenium, Se	5.0E–2 lb/GWh	3.0E–1 lb/GWh	NR

NA = not applicable.
NR = limit not opened for reconsideration (77 FR 9304; February 16, 2012).
[a] Based on best-performing similar source.
[b] Based on DOE information.

Federal Smart Grid Legislation

Over the past decade, Congress has demonstrated its interest in electric grid issues in various ways, including through legislation. The Energy Independence and Security Act (EISA) of 2007 included Title XIII that is specific to the smart grid. Often overlooked in Title XIII is an opening paragraph stating that "it is the policy of the United States to support the modernization of the Nation's electricity transmission and distribution system…." Title XIII goes on to define 10 key features of a modern electrical grid system including dynamic optimization of grid operations, integration of distributed resources, and integration of smart consumer devices, among others. Title XIII also provides for demonstration projects, interoperability, the Smart Grid Task Force, and Federal matching funds for smart grid investments by utilities. These provisions serve as the basis for substantial funds that were authorized under the 2009 American Recovery and Reinvestment Act. Congress continues to consider new legislation to address cyber-security concerns, privacy and data access for consumers, and other policies related to grid modernization.

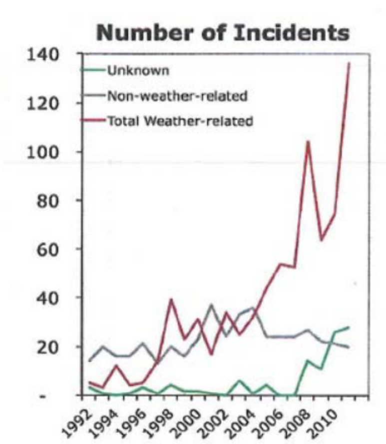
VERY LARGE SCALE WEATHER EVENTS

On October 29, 2012, Hurricane ("Superstorm") Sandy made landfall in southern New Jersey. Sandy pummeled this densely-populated region of the U.S., causing an estimated damage totaling $65 billion and left tens of millions of people without electricity for days or even weeks [43]. Recovery in the affected area continues even now.

In the last two years there have been at least six very large-scale events (VLSEs) in the U.S. including floods, windstorms, snowstorms, hurricanes, and prolonged droughts that have triggered wildfires. These VLSEs are listed in Figure 12 in the top right table. Power delivery systems are vulnerable to these events and data on the left side of Figure 12 suggests that outages from weather-related events are on the rise.

These outages have real cost implications to utilities and consumers. Various studies have concluded that storm-related power outages cost the U.S. economy between $20 billion and $55 billion in a typical year. Depending on the outage duration the interruption could cost an industrial consumer over $4,000 [44]. The true impact on customers is difficult to measure and includes not only inconvenience but often threats to safety and health.

Figure 12. Weather-Related Power Outages



2011-2012 Extreme Events and Reported Customers Affected by Power Outages

Event	Date	Region	Customers Affected*
Superstorm Sandy	October 2012	Northeast	8.1M
"Derecho"	July 2012	Mid Atlantic	4.2M
Early Season Snow	October 2011	New England	3.0M
Hurricane Irene	August 2011	Mid Atlantic	3.2M
Western Wildfires	July 2012	California, Colorado	2.0M
Windstorm	November 2011	Southern California	0.4M

* Adopted from the Energy Information Administration.

Average Cost of a Power Interruption in the U.S.

Duration of Interruption	Residential	Commercial	Industrial
Momentary	$2.64	$733	$2,294
1 Hour	$3.27	$1,074	$3,943
Sustained Interruption*	$3.62	$1,293	$5,124

*The mean duration of a sustained interruption is 106 minutes.

Sources:
Weather-Related Power Outages and Electric System Resiliency.
The Gridwise Alliance. Lessons Learned from Superstorm Sandy and Other Extreme Events. June 2013.

Table 6 shows the variety of causes for outages including weather-related and other causes and the estimated total impact for each cause.

Table 6. Source and Size of Power Outages

		% of events	Mean size in MW	Mean size in customers
Weather Related Outages	Earthquake	0.8	1,408	375,900
	Tornado	2.8	367	115,439
	Hurricane/tropical storm	4.2	1,309	782,695
	Ice storm	5.0	1,152	343,448
	Lightning	11.3	270	70,944
	Wind/rain	14.8	793	185,199
	Other cold weather	5.5	542	150,255
	Fire	5.2	431	111,244
Other causes of outages	Intentional attack	1.6	340	24,572
	Supply shortage	5.3	341	138,957
	Other external cause	4.8	710	246,071
	Equipment failure	29.7	379	57,140
	Operator error	10.1	489	105,322
	Voltage reduction	7.7	153	212,900
	Volunteer reduction	5.9	190	134,543

Since Superstorm Sandy, much more attention is being given to reliability by local leaders who are considering a variety of options for local generation to address the most critical loads. In these cases cost becomes less important, and investments are being made in distributed power systems where standard economic arguments breakdown.

CUSTOMER LOAD AND DEMAND PROJECTIONS

Projections for future electricity needs are being estimated by several organizations. Table 7 shows projections for 2035 electricity sales ranging from 4,421 billion kWh to 5,316 billion kWh with residential sales increasing between 16 and 48 percent as compared to the 2011 baseline. Residential sales are the largest component of electricity sales in all but the Energy Ventures Analysis (EVA) projection [45]. Despite this increase, and as is discussed below, average electricity demand per household is actually expected to drop.

Not shown in this table is the transportation sector. Because of improvements in fuel economy standards, transportation sector energy use is expected to stay constant through 2040. However, electricity sold to the transportation sector is expected to triple to 19 billion kWh in 2040 with increasing sales of electric plug-in LDVs [45] [46]. While small compared to these other areas, electric vehicles might be important at the local distribution level and are discussed further in the Forthcoming Technologies section.

Table 7. Comparison of 2035 Electricity Projections [45]

	2035 Projections in billion kilowatt-hours (kWh)[4]					
	2011 (baseline)	EIA (AEO2013)	IHGSI	INFORUM	NREL	EVA
Electricity Sales	3,725	4,421	5,316	4,406	4,824	4,923
Residential	1,424	1,661	2,001	1,718	*Not reported*	2,116
Commercial/ Other Use	1,326	1,618	1,983	1,710	*Not reported*	2,292
Industrial	976	1,142	1,332	978	*Not reported*	515

Table 8 shows projections for 2035 electricity prices ranging from 10.1 to 11.9 cents per kWh with the highest prices occurring in the residential sector.

Table 8. Comparison of 2035 Electricity End-Use Prices [45]

	2035 Electricity Prices in 2011 cents per kWh4				
	2011 (baseline)	EIA (AEO 2013)	IHGSI	INFORUM	NREL
Average price	9.9	10.1	11.9	10.5	11.7
Residential	11.7	12.1	14.1	12.2	*Not reported*
Commercial	10.2	10.1	12.3	10.6	*Not reported*
Industrial	6.8	7.1	8.1	7.1	*Not reported*

EIA projects average electricity demand per household to decline by 6 percent by 2040 based on less consumption from lighting, PCs, laundry, and refrigeration and increased consumption from HVACs, TVs and other devices [45] [46]. For comparison, an American Council for an Energy-Efficient Economy (ACEEE) study on the long-term energy efficiency potential projects a 2 percent decrease in residential energy use by 2050 with savings coming from heating and lighting [47].

[4] Projections were made by the Energy Information Administration (EIA), IHS Global Insight, Inc. (IHGSI), Interindustry Forecasting Project at the University of Maryland (INFORUM), National Renewable Energy Laboratory (NREL), and Energy Ventures Analysis (EVA).

CENTRAL AND DISTRIBUTED POWER GENERATION

Technological advancements and policies are moving the U.S. generation mix away from coal and towards cleaner technologies such as natural gas, wind, and solar. One Presidential action directs the Department of the Interior to permit 10 Gigawatts (GW) renewables projects (such as wind and solar) on public lands by 2020 [48]. This will impact where and how power is generated on the electrical grid. The variability of wind and solar generation presents more complex control and economic scenarios for grid operators. Energy storage systems are being added to reduce the impact of supply variability and peak demand on transmission and distribution. While providing value they are another component in the system that needs to be monitored, controlled, and optimized. Smaller scale distributed power generation is becoming more economical and widespread, especially when it provides additional features such as high reliability.

Nuclear

The level of nuclear capacity in the U.S. has remained relatively constant for many years, accounting for an approximate 20 percent share of national power generation since the last new reactor came online in Tennessee in 1996. Although five reactors went offline between 1997 and 1998, modifications to existing reactors have compensated for the loss in capacity. Nuclear plants are able to produce energy at rates much closer to their designed capacity than other forms of energy. This allows a relatively small number of plants (104 reactors located in 65 plants as of 2012) to make up a significant share of the U.S.'s actual power generation – generating the most after coal and natural gas in 2011 [49].

Looking ahead, as more reactors are taken offline than are replaced even while electricity demand increases, nuclear energy's share of generation capacity will inevitably decrease in the near term. The U.S. EIA's reference case in the *2014 Annual Energy Outlook* predicts a decrease in nuclear capacity from 102 GW in 2012 to 98 GW in 2020, despite 6.2 GW of new and uprated capacity coming online during this period. Challenging economic conditions which are increasing the operations and maintenance costs of nuclear plants are cited as the reason for many predicted closures. However, EIA also predicts that after 2025, as additional reactors are built, nuclear capacity will return to its original overall capacity [50].

Due to the unique approval process for nuclear power plants, it can be a decade or more between conception and full online status for a reactor. The extensive application, licensing, and regulatory processes and complex construction surrounding nuclear power plants, make it difficult to pinpoint individual completion dates.

The Nuclear Regulatory Commission (NRC) has active applications for 28 new reactors as of 2012, and four new reactors now under construction (Vogtle Units 3 and 4 and Summer Units 2 and 3) are expected to come online between 2017 and 2019 [51]. The new Vogtle reactors, the first to receive construction approval in 30 years, are expected to have a combined capacity of 2.2 GW [52]. The V.C. Summer units are also designed with a 2.2 GW capacity [53]. These are large-capacity plants that well serve base loads but have less flexibility for variable demand.

Worldwide support for nuclear energy understandably dipped after the 2011 Fukushima nuclear disaster. The American Enterprise Institute conducted a public opinion study and while 57 percent of Americans surveyed favored using nuclear energy, 62 percent would disapprove a nuclear power plant in their community [54]. However, according to a March 2013 Gallup survey, 37 percent of respondents they would like more emphasis on nuclear power while 32 percent said they would like less emphasis and 28 percent said they would like the same emphasis [54]. Clearly Americans are divided over nuclear power.

Coal

According to EIA, in 2012, coal was used for about 37 percent of the 4 trillion kWh of electricity generated in the U.S. that year [55]. The National Energy Technology Laboratory (NETL) tracks the development of new coal plants and has found that actual capacity of completed plants has been significantly less than proposed capacity. NETL's 2002 report listed 11,455 MW of proposed capacity for the year 2005 but only 329 MW were actually constructed. In 2011, 1,599 MW of new capacity was announced and 2,890 MW were canceled. Combined capacity of plants scheduled for retirement by 2020 is 24.7 GW or 7 percent of the total U.S. coal generation capacity [56].

There are several projections on coal's viability as a generation source over the intermediate and long-term, and they make differing predictions. NERC showed coal's contribution to be approximately 30 percent in 2012 and projects its share of the market will drop to less than 27 percent by 2022 based on 16 GW of capacity retirement [28]. EIA's reference case shows coal-fired plants as the largest source of electricity generation in 2011 at 42 percent with its market share declining to 35 percent in 2040. Other EIA scenarios show coal-fired generation could be between 28 percent and 40 percent by 2040 [29]. EIA also projects that by 2040, 15 percent of the coal plants active in 2011 will be retired while only 3 percent of new generation capacity added will be from coal. This is due to Federal and state environmental regulations and uncertainty about future limits on greenhouse gas emissions such as CO_2 [45] [46].

One example of where regulations are affecting coal generation is at the Tennessee Valley Authority (TVA). In 2010 the TVA entered into consent agreements with EPA, four states, and several environmental groups over the pollution from 11 coal-fired power plants. TVA is in the process of retiring 30 percent of its coal fleet and evaluating the compliance cost for much of the rest [57]. Economic decisions based on environmental regulations, life of the plants, and presently inexpensive natural gas are contributing to the shifting capacity mix.

Large power plants have high capital costs that are recuperated over the life of the plant, typically 20 or more years. Once coal-fired generation is replaced, it is unlikely that utilities will switch back. While newer generation technologies are cleaner, their capital and operational costs will be different, and utilities will need to address these issues in their business models.

Natural Gas

There has been a surge in production of natural gas in the U.S. due to the shale revolution increasing recoverable supplies and bringing down prices for this fuel. Low natural gas prices have created more demand for natural gas from the power sector [58].

According to EIA, in 2012, natural gas was used for about 30 percent of the U.S. electricity generated [55]. There are several projections on natural gas as an electricity generation source. The Joint Institute for Strategic Energy Analysis (JISEA) studied natural gas in the energy sector, and in its "Baseline – Mid-EUR" case, it projected natural gas combined-cycle and natural gas combustion-turbine capacities nearly doubling from 2010 to 2050 [59]. NERC showed natural gas generation to be 38.5 percent in 2012 and projects the natural gas share of the market will increase to 39.7 percent by 2022 based on 32 GW of capacity additions, although conceptual projections show an additional 68 GW [28]. EIA shows natural gas generation increasing its market share from 24 percent in 2011 to 30 percent in 2040 with natural gas-fired plants accounting for 63 percent of capacity additions during that period. Inexpensive natural gas makes existing natural gas plants more competitive with coal and lower capital costs makes natural gas-fired plants a viable choice for new generation capacity [29].

Forecasts of the future price of natural gas vary significantly. To hedge against increasing natural gas prices many utilities lock in fuel prices from suppliers. Should natural gas prices increase in the future the utilities will typically pass those costs along to consumers with a potentially major impact on the cost of their electricity.

Wind

In the last five years, there has been a surge in wind power deployments across consumer, industrial, and commercial sectors in the U.S. In 2012, cumulative land-based wind deployment was 60 GW as compared to 12 GW five years earlier. In 2012, wind deployment accounted for 43 percent of new electrical generation capacity in the U.S., the most of any generation technology. Additionally, the combined potential of land-based and off-shore wind is about 140 quads (quadrillion BTUs), which is 10 times U.S. electricity consumption today [60].

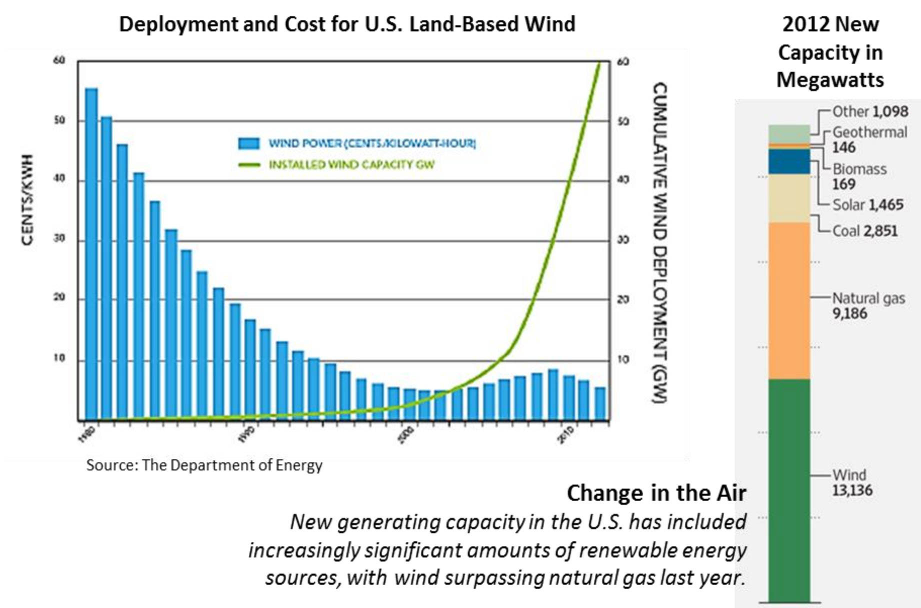
The success of wind deployments can be attributed to a variety of factors. These include the increase in turbine size which lowers the cost; the larger production volumes that also helps to lower costs; production tax credits; and the improved capacity factor of plants from sophisticated operators, which increase the time plants are operational and thus producing revenues [60].

Looking ahead, DOE estimates that as much as 20 percent of projected U.S. electricity demand by 2030 could be met by wind power given policy support and continued technological improvements [61]. Although wind represents at present only 3.5 percent of the total electricity market, it is growing rapidly and regionally where the resource is abundant. For this reason, wind power is poised to be disruptive to other power generation technologies. Integration studies such as *Western Wind and Solar Integration Study* and the *Eastern Renewable Generation Integration Study* are being completed to examine the impact large penetrations of variable generation sources will have on the electrical grid, and on the development of planning and operations tools for flexibility and stability of the electrical grid [62] [63].

Figure 13 provides an overview of land-based wind energy assets in the United States including a time-series chart of the deployment (installed capacity in GW) and cost (in cents/kWh) and a bar chart of new capacity additions in 2012.

There has also been tremendous growth in wind energy outside the United States, especially in Europe. By the end of 2012, Europe had 110 GW of wind capacity on the grid [64]. Germany is home to over 21,500 wind turbines, a fact that has posed some interesting challenges for the country. When generation exceeds demand and energy storage is not feasible, generation must be shed. However, German energy laws stipulate that non-green power generation must be shed first, lowering the capacity factor and revenues for those plants. Another challenge has been the variable nature and high concentration of wind on the electrical grid. This has resulted in large changes in capacity requiring new tools and methods for system operations to improve flexibility and maintain network stability [65].

Figure 13. Wind Power Deployment



Source: The Department of Energy

Change in the Air

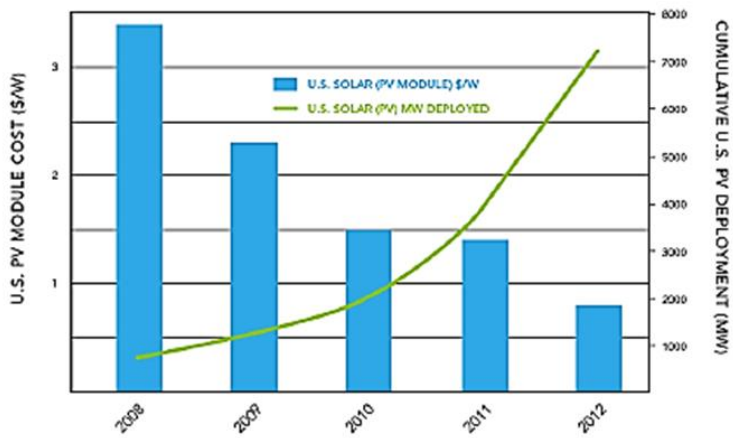
New generating capacity in the U.S. has included increasingly significant amounts of renewable energy sources, with wind surpassing natural gas last year.

Source: The Wall Street Journal

Solar

Solar is another renewable power generation technology that has made tremendous strides in recent years. As shown in Figure 14, cumulative solar photovoltaic (PV) deployment in 2012 was 7.3 GW, 10 times the deployment capacity of 2008. The EIA's AEO2013 projects commercial PV capacity increasing between 6.5 and 7.4 percent annually through 2040, depending on various policy scenarios [29]. As with wind, solar represents a small portion of total electricity market, but it is growing rapidly and regionally where the resource is abundant. For this reason, it too can be both disruptive to other power generation technologies and pose challenges to the electrical grid.

Figure 14. U.S. Deployment and Cost for Solar PV Modules [60]



Solar deployment costs are comprised of the PV module and any inverters or batteries (i.e., equipment costs) and the so-called “soft costs” for permitting and installation. The drop in cost for a PV module is partly responsible for the dramatic increase in deployment. As the blue bars in Figure 14 show, PV module costs since 2008 have dropped by a factor of four to a 2012 price of about $0.80/watt. Soft costs in the U.S. are still high, averaging about $3.34/watt or approximately five times those of Germany. However, utility incentives, new financing options, and the current 30 percent Federal investment tax credit (scheduled to revert to 10 percent in 2017) have helped this technology achieve cost parity with electrical generation from natural gas, coal, and oil in many parts of the U.S. and put this technology within reach for the average homeowner or business [29] [60].

By 2030 local solar projects likely will be of sufficient scale to impact the operations of many local utilities. There are several large examples of distributed solar generation coming on-line in the U.S. The retail giant Walmart has installed solar PV modules on about 200 of its ~100,000 square foot stores delivering over 71 million kWh of energy annually. With about 4,500 stores in the U.S., and a goal of being served by 100 percent renewable energy, this could be a significant impact on the electrical grid [66] [67]. Figure 15 shows one such Walmart store with a large rooftop array of solar PV modules.

Figure 15. Distributed Solar on Walmart Store [67]

In Arizona roughly 500 new rooftop solar installations are completed each month. The state's largest utility, Arizona Public Service (APS), has 20,000 homes in its territory with solar PV modules. Residential systems are generally on the order of 7 kW, resulting in a reduction of about two-thirds in the electrical utility bills for these houses. However, Arizona utilities argued that with the net metering practice, these homeowners were unfairly benefiting from the electrical grid's 24/7 power supply without paying for the maintenance costs for power plants and transmission lines. In November 2013, the Arizona Corporation Commission voted to add a monthly fee of $0.70/kW to the bills of all customers that install new solar systems. In other states, utilities have the same argument so this Arizona vote may create momentum to levy a similar fee in other states [68].

Europe's experience with integrating solar energy could benefit the U.S. By the end of 2012, Europe had 70 GW of solar capacity on the grid with 22.3 GW in Germany [64]. As with other renewable resources, solar generation is variable, and this can produce load balance issues for the grid. A case in point occurred in Germany one day in February 2013, when its national electric grid experienced a large positive system imbalance due to this variability. On this day there was quite a bit of snow on the PV modules that did not melt as estimated, which resulted less power from the PV and a system imbalance which required an activation of reserves [64]. Forecasting accuracy of solar generation will be increasingly important as more PV modules are installed.

Other Renewables

While wind and solar energy will tend to dominate in the next decade and beyond, other renewable resources such as geothermal, hydroelectric, and biopower will also have an impact. The EIA AEO2013 shows that the renewable generating capacity of the combination of all renewable energy technologies will account for nearly one-fifth of total generating capacity in 2040 [29]. The National Renewable Energy Laboratory (NREL) concluded in its *Renewable Electricity Futures Study* that a combination of a flexible electric system with today's commercially-available renewable electricity generation technologies can supply 80 percent of total U.S. electricity generation by 2050 [69].

Geothermal resources are found primarily in the American West and Southwest. The technology is emerging still but the potential for this resource is about 500 GW according to NREL. Hydroelectric energy ("hydropower") is already a primary source of energy in the Pacific Northwest. NREL estimates the U.S. hydropower potential is 152 to 228 GW [69]. Biopower is available in many regions and with an increase in energy crops and harvesting technologies in the future, NREL estimated a corresponding 100 GW of dedicated biopower capacity [69]. By contrast AEO2013 projects much smaller amounts of geothermal (5 GW) and biopower (7 GW) plants entering operation. While these numbers are much less than wind and solar, they nevertheless represent a doubling in biopower capacity and a tripling in geothermal capacity from 2010 to 2040 [29].

FORTHCOMING TECHNOLOGIES

New companies are emerging that are focused on providing new energy products to consumers. Established companies such as Home Depot, Lowes and Best Buy are focused on relatively inexpensive products that integrate energy management devices with other home automation products. Other companies are focused on commercial scale energy storage, fuel cells, etc. with an emphasis on convenience and security. While only some of these products will ultimately be commercially successful in these emerging markets, it is clear that innovation is just beginning.

High Voltage Direct Current Transmission

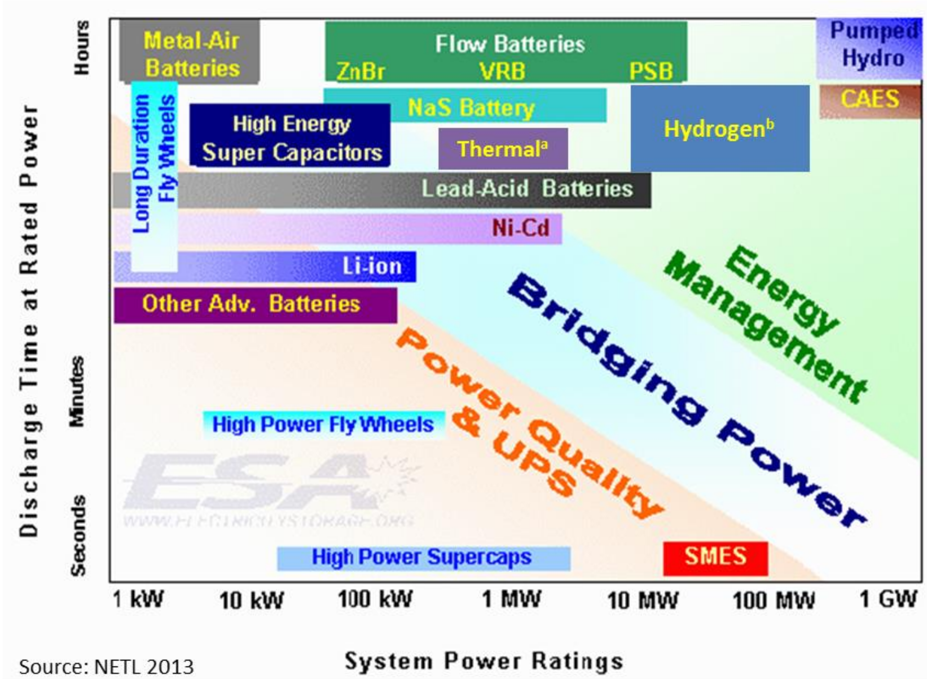
High-voltage direct current (HVDC) was the first means of transmitting electric power over a distance. Today this technology is re-emerging as a possible replacement for alternating current (AC) high voltage lines. DC lines result in overall higher efficiency and reliability than an equivalently-sized AC system [70]. There are approximately 4,000 circuit miles High Voltage DC lines in the U.S. whereas there are over 180,000 circuit miles of AC lines [71]. Countries such as Sweden, Germany, China and Brazil also have HVDC transmission lines. Clean Line Energy is developing a series of direct current (DC) transmission lines to deliver thousands of megawatts of renewable power from the windiest areas of the U.S. to cities with a strong demand for clean, reliable energy. They are proposing to develop four high-voltage, direct-current transmission lines, each capable of transporting up to 3,500 MW of renewable energy from renewable-rich regions in the Midwest to load centers in the Eastern and Western U.S. [72].

Energy Storage

Today's grid operator manages most fluctuations on the electrical grid by adjusting generation to maintain reliability and to adhere to strict conventions on voltage and frequency. In the future, clean energy variable generation such as wind and solar will have significantly increased, and policies are already in place or underway in most states to give them preference in meeting demand needs. Given the increased variability, energy storage technologies may provide flexible solutions throughout the electricity value chain.

Energy storage systems are designed with different energy densities, response times, time of operation, and power levels depending on the target application. The primary issues energy storage systems address are energy management, bridging power, and power quality. There are several technologies available that perform these energy storage functions from pumped hydro, which is a fairly mature technology, to capacitors and flywheels, which are only feasible in niche markets today. Figure 16 shows the discharge time for different types of energy storage systems (i.e., different system power ratings) and the primary issues that each type addresses.

Figure 16. Power Ratings and Discharge Times for Energy Storage Technologies



Source: NETL 2013
a. Source: Sopogy 2013.
b. Source: NREL 2010.
CAES = compressed air energy storage; Li-ion = lithium-ion; Ni-Cd = nickel cadmium; NaS = sodium sulfur; PSB = polysulfide bromide; SMES = superconducting magnetic energy storage; VRB = vanadium redox battery; ZnBr = zinc bromide

There are several examples of these technologies already deployed within the grid. Sodium sulfur (NaS) batteries have been in commercial use for over 10 years at the megawatt scale with over 300 MW installed globally. On the consumer side thermal energy storage systems are being used for bridging power applications and to help shave peak demand. Thermal storage uses off-peak electricity to store cooling or heating energy and then during peak demand uses that energy to meet power needs. The fashion retail store Nordstrom at the Ala Moana Center in Honolulu uses this technology to produce 43 tons of ice every night which helps cool the 210,000 square foot store during the day. Figure 17 shows the rooftop thermal energy storage system at the Ala Moana Center. As a result, the three-story store uses about half the electricity of a similarly sized retailer during daytime hours [73].

Figure 17. Rooftop Thermal Energy Storage [73]

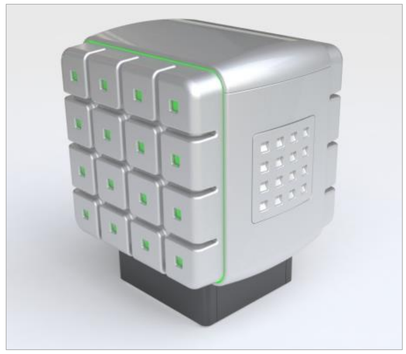
Energy storage is gaining state support. California now has a mandate for increasing energy storage that requires that the state's investor-owned utilities must begin buying a combined 200 MW of energy storage technology by 2014 and reaching 1,325 MW by the end of 2020. This recent decision was made in accordance with state law AB 2514, which was passed in 2010 and calls for the integration of renewable energy and the reduction of greenhouse gas emissions of 80 percent below 1990 levels by 2050 [74].

Fuel Cells

Appliance-size fuel cells that provide both heat and power are just emerging today, but they may very well be common place in 2030 and beyond. These systems will decrease vulnerability associated with electrical grid outages by generating their own electricity for users with a system nearly impervious to hurricanes, thunderstorms, and similar dangers, while simultaneously helping the environment.

Redox Power Systems is working on a solid oxide fuel cell for residential applications that is 1/10th the size and cost of commercial units today with a nameplate capacity of 25 kW. Figure 18 shows a picture of such a residential fuel cell design. The system uses natural gas fuel to electrochemically convert methane to electricity. The goal is to generate onsite power and, optionally, off-the-grid capability at a price competitive with current energy sources [75].

Figure 18. Redox Power Systems Residential Fuel Cell Design [75]

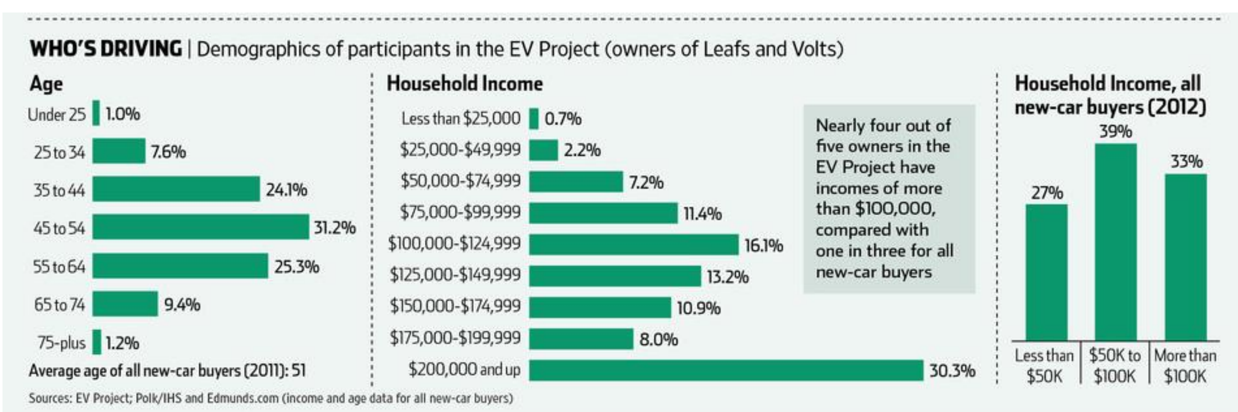


Electric Vehicles

Electric vehicle (EV) sales account for less than 1 percent of total new light duty vehicle sales but several incentives are aimed at boosting their adoption [76]. Today's EV purchasers are primarily city dwellers in places such as Los Angeles, San Francisco, Seattle, New York, and Atlanta. Figure 19 provides a demographic snapshot of who drives EVs and includes information on age and household income. The largest group of purchasers tends to be between the ages of 45 and 54 with household incomes greater than $100,000. EV drivers typically drive 9,000 miles per year as compared to 13,500 miles per year for all cars in the United States [77]. Figure 19 also compares this income information to the 2012 household income of all new-car buyers.

> "In March 2012, President Obama announced the *EV Everywhere Grand Challenge*—to produce plug-in electric vehicles (PEVs) as affordable and convenient for the American family as gasoline-powered vehicles by 2022." [101]

Figure 19. Demographics of PEV drivers [77]



Despite the limited demographic purchasing EVs, there are several factors at play helping to increase the general market penetration. These include the following:

- President Obama's launch of the EV Everywhere Grand Challenge to make the cost of plug-in EVs on part with gasoline-powered vehicles by 2022.
- The nearly 50 percent drop in the cost of EV batteries that has occurred in the past four years through high volume production [78].
- DOE's efforts with industry and academia to double the battery pack energy density [78].
- State support, in particular, eight states (California, Connecticut, Maryland, Massachusetts, New York, Oregon, Rhode Island, and Vermont) that have pledged to adopt measures to make it easier to own an EV. Collectively these states represent nearly one-quarter of America's auto market. Their shared goal is to achieve sales of at least 3.3 million zero-emissions vehicles by 2025. This would represent 25 percent of the light duty vehicle (LDV) annual sales [79].

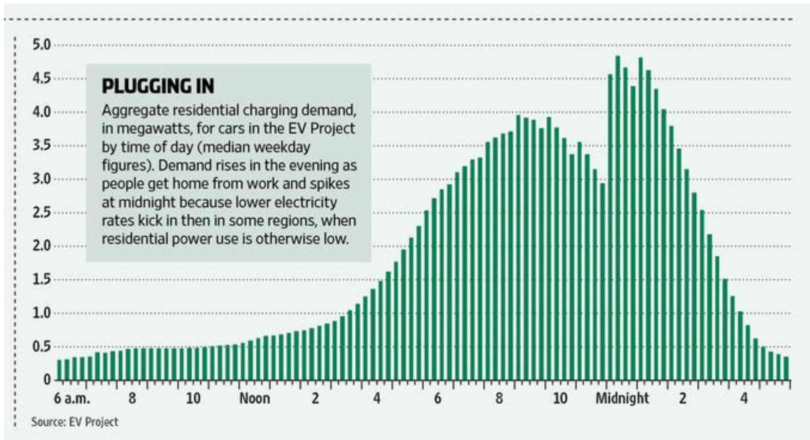
Other factors positively influencing EV market share are purchasing incentives such as the Federal government tax credit of up to $7,500 and state government incentives such as tax credits and rebates [80]. Lastly, there is the large difference in fueling costs between EVs and conventional gasoline-powered vehicles. Nationally, EV fueling costs are about one-third those for vehicles running on gasoline.

Together, all of these factors are aligned with promoting and expanding EV market share. With this increased market penetration, though, will come significantly increased transportation sector demands for electricity.

The vehicle industry has been working tirelessly installing charging stations nationwide. As of June 2013, there were over 18,000 charging stations (both public and private) across the U.S. with a dozen states (including Arizona, California, Florida, Illinois, Massachusetts, Michigan, New York, North Carolina, Oregon, Tennessee, Texas, and Washington) representing the majority of all installations [81]. In support of the President's EV Everywhere Challenge, DOE has launched the Workplace Charging Challenge aimed at increasing by tenfold over the next five years the number of U.S. employers offering EV charging installations [82].

Already there are several neighborhoods with high EV concentration. Pecan Street Research (PSR) Analytics analyzed over 2,500 vehicle charge events between June 1, 2013 and August 31, 2013 in a randomly selected subset of 30 homes in Austin, Texas. It found that charging behavior is more diverse than predicted and thus representing a much more manageable energy load [83]. However, how charging will impact the electrical grid still remains to be seen. Today, a majority of residential charging is done with Level 1 and Level 2 chargers. In the State of Washington, some of the 14 DC quick chargers on the West Coast Green Highway were used 10 times more often than others [84]. In 20 years, technological advancements could make these quick chargers, wireless charging, or some other charging method common in the home. With states supporting a larger number of EVs in the market place, utilities will need to evaluate their distribution systems against these possible demand scenarios. Figure 20 shows aggregate residential charging demand (in MW) over the course of a typical day.

Figure 20. Residential Demand in a High PEV Penetration Neighborhood [77]



Demand Side Components

Data from the *Buildings Energy Data Book* of March 2012 shows residential and commercial buildings consume 74 percent of U.S. electricity, and this figure is forecasted to grow a few percentage points by 2030 [85]. Some of the end-use consumption is from lighting, PCs, water heating, refrigeration, cooking, and HVACs. Lighting, in particular, has undergone a dramatic change in recent years as described below. In addition, low-cost, high-power computing has created opportunities for network-connected smart appliances with alert and remote control features for residential use. Commercial and industrial organizations are often looking to reduce bottom line operational costs through operational efficiency improvements. As a result, improvements in the end-use components have the potential to significantly affect how electricity is consumed.

Light Emitting Diode (LED) Lighting

Both residential and commercial consumers are making the switch to light emitting diode (LED) lighting technology (also called solid state lighting technology). In 2009, fewer than 400,000 LED lights were deployed across the U.S., but by 2013, deployment had grown to nearly 20 million LED lights, an increase of 50 times. Although LEDs cost more up front, they also last as much as 25 times longer than the traditional incandescent light bulb. In 2012 some LED lighting products cost $50 each, but one year later many LEDs cost less than $15 [60].

Additionally, the consumer gains quite a bit from a LED lighting product's efficiency. Consider that a standard 60-watt incandescent light bulb can be replaced by a ~9-watt LED light that is 84 percent more efficient and with much less wasted heat. With the LED lasting over two decades, consumers could save over $140 for every incandescent bulb swapped for an LED replacement. DOE's Office of Energy Efficiency and Renewable Energy (EERE) projects that by 2030 LED solid-state lighting will save Americans over $30 billion a year in electricity costs and cut America's energy consumption for lighting in half [60].

This transition in lighting impacts not only utilities' revenues but also their operating costs. Incandescent bulbs have a power factor (PF) of about 1, which means the actual power consumed (in watts) and the apparent power (in volt-amperes) are equal. However, Energy Star has a minimum PF of 0.70 for LED lights greater than 5-watts and no minimum PF for LED lights less than 5-watts [86]. This means a 10-watt LED with a PF of 0.7 pays for 10 watts, but the utility would have to generate 1.4 times that power in volt-amps to run that light and pay for the additional generation. At the individual bulb level this is not significant but as LED lighting products gain more market share, the aggregate additional power needs will become an important consideration for utilities [87].

Residential

New refrigerators, dishwashers, washers, dryers, thermostats, carbon monoxide detectors, and smoke detectors are being sold with embedded computers capable of providing consumers monitoring, user habit learning, customizability, remote notification, and 24/7 remote control. Appliances such as washing machines and dishwashers can be programmed to operate during times convenient for the consumer or during the evening to minimize the noise disturbance from the operation. In the future, these appliances could be configured to respond to demand response signals or time differentiated rates to maximize savings for the customer, to modify peak demand, and in general to help improve grid operations. These appliances represent only a tiny fraction of the market today, but they are expected to become increasingly mainstream in market penetration through the 2010s and could reach up to $35 billion in sales by 2020 [88].

Commercial and Industrial

Building energy demand, a major cost component of any business operation, can be broadly divided into lighting, general heating and cooling, and plug load. By implementing smart efficiency measures, such as those listed in Table 9, it is estimated that by 2035 the annual savings for the commercial sector from these technologies could reach $30 billion to $60 billion [89]. Similarly, for the industrial sector, annual savings by 2035 could range from $8 billion to $25 billion [89]. This expected improved building efficiency could help reduce electricity demand growth as the technologies become more widely deployed and even newer technologies are developed. These technologies will increasingly allow buildings to respond in near real-time to grid conditions such as voltage and frequency levels.

Table 9. Intelligent Energy Measures for Commercial Sector [89]

Measure	Savings Range	Estimated Applicability
Smart Building Components	5% - 20%	10%
Smart Lighting	0% - 75 %	35%
Smart HVAC Components	15%	10% - 15%
Advanced Building Mgmt. Systems (BMS)	10% - 30%	10% - 20%
Smart Grid	10%	10%
User Interfaces	10% - 20%	10%
Office Equipment and Cloud Computing	2% - 50%	50%
Refrigeration Energy Management	30%	30%
Smart Fume Hoods	10% - 30%	15%
Miscellaneous	20% - 50%	2%

CONDITION AND REACH OF EXISTING INFRASTRUCTURE

The electrical grid connects approximately 144 million end-use customers with about 5,800 major power plants and includes over 450,000 miles of high voltage transmission lines [90]. In recent decades, the majority of transmission investment has been directed toward constructing new facilities to meet customer load demands. Meanwhile, relatively little has been invested in refurbishing existing facilities. This has resulted in much of the current power system infrastructure, whether generation, transmission, or distribution equipment, becoming outdated and in need of refurbishment, replacement, or upgrades in order to comply with new standards and meet demand [28].

Nearly 70 percent of the grid's transmission lines and power transformers are now over 25 years old and the average age of U.S. power plants is over 30 years [90]. Some transmission and distribution components are over 80 years old. In the latter half of the upcoming 10-year period, a number of nuclear units are expected to undergo refurbishment or retirement. A number of coal units will cease burning coal by 2014, with conversion to other fuels being considered as just one of several options [28].

Updating the existing infrastructure will present many challenges such as the availability of spare parts, the obsolescence of older equipment, the ability to maintain equipment due to outage scheduling restrictions, and the aging of the work force and resulting lost knowledge due to personnel retirements. Although many companies have sustainment programs in place for asset renewal, NERC asserts that it is the overall scope of the problem that presents the greatest challenge [28].

These updates will become more and more necessary as the age of infrastructure begins to show. The grid resiliency report entitled *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages* issued by the Executive Office of the President in August 2013 states the following:

"The age of the grid's components has contributed to an increased incidence of weather-related power outages. For example, the response time of grid operators to mechanical failures is constrained by a lack of automated sensors. Older transmission lines dissipate more energy than new ones, constraining supply during periods of high energy demand. And, grid deterioration increases the system's vulnerability to severe weather given that the majority of the grid exists above ground." [90]

However, the carrying capacity of existing lines is expensive and time consuming to upgrade. DOE-funded analysis currently underway at the Idaho National Laboratory aims to increase transmission capacity during windy conditions through concurrent cooling of the transmission line and through monitoring and controls of a Dynamic Line Rating Tool. An increase in wind speed of 5 mph blowing at a right angle to a high-voltage line can cool the line enough to increase its carrying capacity 30 to 50 percent. By applying this knowledge to the Dynamic Line Rating Tool, the existing infrastructure can allow for increased levels of generation with minimal grid upgrades [91].

In addition to analysis, the Federal government has allocated billions of dollars to replace, expand, and refine grid infrastructure. The American Recovery and Reinvestment Act of 2009 allocated $4.5 billion for investments in technologies to modernize grid. These smart grid technologies utilize remote control and automation to better monitor and operate the grid. Between June 2011 and February 2013, Recovery Act funds have been used to deploy 343 advanced grid sensors, upgrade 3,000 distribution circuits with digital technology, install 6.2 million smart meters, and invest in 16 energy storage projects. These investments have contributed to significant increases in grid resilience, efficiency, and reliability [90].

Smart Grid Projects/Technologies

The American Recovery and Reinvestment Act of 2009 tasked DOE with distributing $4.5 billion in funding to smart grid projects across the country. This program has the potential to drastically change the power grid landscape of the United States. The two largest initiatives are the Smart Grid Investment Grant (SGIG) program and the Smart Grid Demonstration Program (SGDP). DOE's Office of Electricity Delivery and Energy Reliability (OE) is responsible for managing these five-year programs [92].

The first of these large initiatives, SGIG, focuses on deploying existing smart grid technologies, tools, and techniques to improve grid performance. Meanwhile, the other large initiative, SGDP, explores advanced smart grid and energy storage systems and evaluates performance for future applications. These projects are focused on regional demonstration projects and energy storage projects. For information about individual smart grid projects under the American Recovery and Reinvestment Act of 2009, visit http://www.smartgrid.gov/recovery_act/project_information.

While the impact of these investments is still being analyzed in most cases, the benefits are clear. Based on the results of these projects, the industry will develop new and better solutions and fine tune the design and implementation for future projects to maximize the benefits.

Microgrids

A microgrid is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that collectively acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island-mode [93].

North America is the leading market for microgrids, featuring 63 percent (992 MW) of the total worldwide installed microgrid capacity of 1,581 MW [94]. This worldwide capacity is expected to increase to over 9,100 MW by 2020 with North America's share of this capacity expected to grow to almost 6,000 MW. Worldwide annual revenue from microgrids is expected to reach between $30 million and $60 million by 2020 [94].

The U.S. Department of Defense (DoD), as the single largest energy consumer in the world, is a crucial driver of microgrid development owing to its extreme sensitivity to T&D disruptions at its various bases around the world. Roughly two dozen facilities across all branches of the military are engaged in some form of microgrid implementation, often including the integration of renewable energy generation such as wind and/or solar [95].

Beyond DoD, public investment has come from various Federal and state agencies including DOE, the Federal Emergency Management Agency, and the California Energy Commission. Some of the larger projects are occurring at the University of California, San Diego; in Salem, Oregon; and in Bridgeport, Connecticut. These projects focus on topics such as islanding, EV integration, environmental disaster response, and distributed renewable energy generation management.

Managing microgrid integration is an important aspect of grid evolution, both because this integration requires careful planning, and because this is a crucial element in solving current grid issues such as distributed renewable energy generation and increasing grid resiliency during natural disasters.

"Smart Cities"

The term "Smart City" currently has a number of different connotations depending on where and how the term is specified. For some cities, this is as simple as smart street lighting; for others, it refers to a highly-integrated sensor network that provides real-time information regarding city service usage such as beaches, libraries, and parking. European cities such as Málaga [96] and Eindhoven [97] fall into the former category, while cities such as Santander [98] exemplify the latter concept.

In general, though, the term refers to the real-time creation and consumption of data streams in order to provide an adaptive or informed response to a citizen need or demand. Planning organizations are just starting to design smart cities, making it a clear priority looking forward. It is already impacting energy consumption data availability in many cities.

The amount of data being created and collected by municipalities and utilities is growing rapidly and by some estimates, it is expected to double every two years until 2020 [99]. The data will largely be generated by vast automated sensor networks. This "Internet of Things" is expected to generate an estimated 40 trillion gigabytes of data [99]. Leveraging the data will be fundamental for municipalities to understand, because it is one of the basic components of the value architecture of future smart cities. Without understanding what is being measured and what that measurement says, municipalities and utility operators run the risk of being drowned by a metaphorical tsunami of unintelligible data points and statistics, or, worse yet, drawing the wrong conclusions by using answers to questions they did not want to ask [100]. Figure 21 provides a schematic representation of this smart city value architecture. It shows high-level characteristics as well as more specific features, components, and desired outcomes.

Moving forward, electrical grid stakeholders need to be both intelligent providers and consumers of smart city data and services. This means planning grid development in conjunction with local and regional planning authorities in order to maximize participation in smart cities.

Figure 21. Smart City of the Future Value Architecture [99]

While still in their infancy, these kinds of plans represent the next evolution of large scale city planning, and have many details to work out (e.g., privacy concerns, etc.).

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APPENDIX A - KEY FINDINGS FROM NERC 2012 LONG-TERM RELIABILITY ASSESSMENT

Significant Fossil-Fired Generator Retirements Over Next Five Years

Due largely to the unique confluence of final and potential environmental regulations, low natural gas prices, and other economic factors, about 71 GW of fossil-fired generation is projected to retire by 2022, with over 90 percent retiring by 2017. With the exception of the Electric Reliability Council of Texas (ERCOT), the retirement of this capacity does not pose significant resource adequacy concerns. Reserve Margins are likely to be reduced, but to levels that are still above targets. However, retirements over the next three to four years may raise issues related to system stability and the need for transmission enhancements, which if not addressed could cause reliability concerns in some areas.

Increased Risk of Capacity Deficiencies in ERCOT as Planning Reserve Margins Projected to Fall Below Targets

Starting as early as next year, the ERCOT Planning Reserve Margin is anticipated to be 13.4 percent, which is below the NERC Reference Margin Level and ERCOT planning target of 13.75 percent. At these levels, the risk of insufficient generation resources to meet peak demand increases beyond reliability targets.

Resources Sufficient to Meet Reliability Targets in Most Areas

For the majority of the bulk power system, Planning Reserve Margins appear sufficient to maintain reliability through the long-term horizon. However, there are significant challenges facing the electric industry that may shift industry projections, adding considerable uncertainty to the long term assessment. Future uncertainties include electricity market changes, fuel-prices (natural gas, in particular), potential environmental regulations, and renewable portfolio standards.

Increased Dependence on Natural Gas for Electricity Generation

Increased dependence on natural gas for electricity in some areas has increased the need for all gas users, electric system planners and operators, and policy makers to focus more sharply on the interaction between the electric and gas industries. The adoption of highly efficient combined-cycle technology by the electric power industry and the emergence of shale gas have altered the relative economics of gas-fired generation. As a result, the dependence on natural gas by the electric power sector has increased significantly. Trends in fuel-mix changes highlighted in this assessment identify gas-fired generation as the primary choice for new capacity with almost 100 GW of Planned and Conceptual capacity expected over the next 10 years, which represents almost half of all new generation capacity.

Long-Term Generator Maintenance Outages for Environmental Retrofits

A significant generation retrofit effort is expected over the next 10 years in order to comply with Federal and state- level environmental regulations. A majority of environmental controls are expected to be put in place to meet air regulations by April 2016. In total, 339 unit-level retrofits on fossil-fired generation will be needed, totaling about 160 GW. However, there is still significant uncertainty in the forecasted values as maintenance schedules have not yet been fully evaluated by all areas.

Renewable Resource Additions Introduce New Planning and Operational Challenges

Renewable resources are growing in importance in many areas of North America as the number of new facilities continues to increase. The share of capacity from renewable resources will continue to grow, especially as significant additions are projected for both wind and solar throughout North America. In 2012, renewable generation, including hydro, made up 15.6 percent of all on-peak capacity resources and is expected to reach almost 17 percent in 2022. Contributing to this growth is approximately 20 GW of on-peak Future-Planned capacity and an additional 21.5 GW of on-peak Conceptual capacity. It is vital that these variable resources are integrated reliably and in a way that supports the continued performance of the BPS and addresses both planning and operational challenges.

Transmission Growth to Accommodate New and Distant Resources

As recent as five years ago, transmission was being constructed at a rate of about 1,000 circuit miles per year. In the last five years, over 2,300 circuit miles were constructed per year, more than doubling actual builds in the previous five years. With the current plans in place, that rate is expected to increase to 3,600 miles per year over the next five years. NERC-wide, almost a quarter of new transmission is specifically linked to the integration of renewable generation.

Increases in Demand-Side Management Help Offset Future Resource Needs

All areas are projecting at least some increased availability of Demand-Side Management (DSM) over the next 10 years to reduce peak demands, contributing either to the deferral of new generating capacity or improving operator flexibility in day-ahead or real-time time operations. NERC-wide, DSM is projected to total roughly 80,000 MW by 2022 (or about 7 percent of the on-peak resource portfolio), offsetting approximately six years of peak demand growth. However, unlike traditional generating resources with many decades of historic data for analysis, the long-term projections of DSM involve greater forecasting uncertainty—particularly with Demand Response resources.