U.S. Department of Energy
Washington, DC 20585

Date: **September 4, 2014**

To: **Members of the Public**

From: **Quadrennial Energy Review Task Force Secretariat and Energy Policy and Systems Analysis Staff, United States Department of Energy**

Re: **Stakeholder Meeting on Electricity Transmission, Storage, and Distribution**

This memo is an updated version of the July 7 background briefing memo issued as background for the July 11 QER Electricity Transmission, Storage and Distribution - West Stakeholder Meeting in Portland, OR. Available at www.energy.gov/QER.

Primarily, this memo is the same except for the addition of a section on regulated utility business models and their regulation. The September 8 Newark, NJ QER Electricity Transmission, Storage and Distribution - East Stakeholder Meeting will include a panel on the business models issue, instead of a storage panel that occurred at the July 11 meeting.

Introduction

On January 9, 2014, President Obama issued a Presidential Memorandum establishing a Quadrennial Energy Review (QER). The Secretary of Energy provides support to the QER Task Force, including coordination of activities related to the preparation of the QER report, policy analysis and modeling, and stakeholder engagement.

On Monday, September 8, 2014, at 9:00 a.m. in the Campus Center-Ballroom of the New Jersey Institute of Technology in Newark, NJ, the U.S. Department of Energy (DOE), acting as the Secretariat for the QER Task Force, will hold a public meeting to discuss and receive comments on issues surrounding electricity transmission, storage, and distribution (TS&D), with a particular focus on the eastern electricity interconnection of the United States.

A similar meeting, but for the west, was held on July 11, 2004 in Portland, OR.

In Newark, three expert panels will explore evolving trends in the U.S. electricity sector, and there will be an opportunity for public comment via an open microphone session beginning at 1:15 p.m. Written comments can be submitted to QERcomments@hq.doe.gov. The session will also be webcast; at www.energy.gov/live.

The series of 14 total QER public meetings will conclude with one on Finance and Market Incentives in New York, NY and a final Wrap-up Meeting in Washington, DC. More information on these final two QER meetings will be posted at www.energy.gov/qer as it becomes available.

1. Framing and background

Today's grid is an engineering wonder of the modern world (see Figure 1). But to serve a 21st century consumer base, the grid must adapt to emerging challenges and opportunities: fluctuating energy prices, an increasingly transactive role for customers, integration of distributed energy resources, the need for improved resilience, and the need to act as an enabling platform for reducing greenhouse gas emissions. The future grid will likely accommodate and rely on an increasingly wide mix of resources, including large centralized and more diffuse distributed generation – some of it intermittent in nature. Energy storage and responsive (transactive) load may also play an important role.

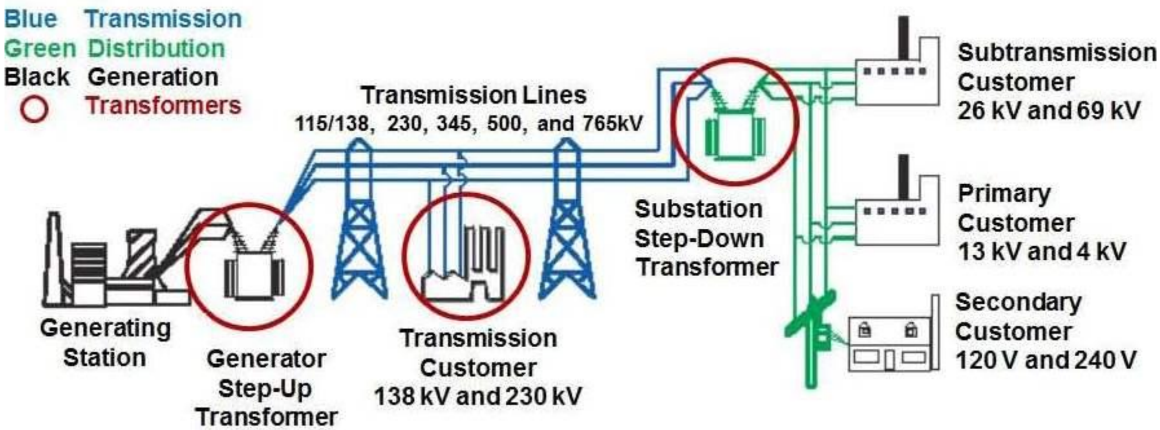
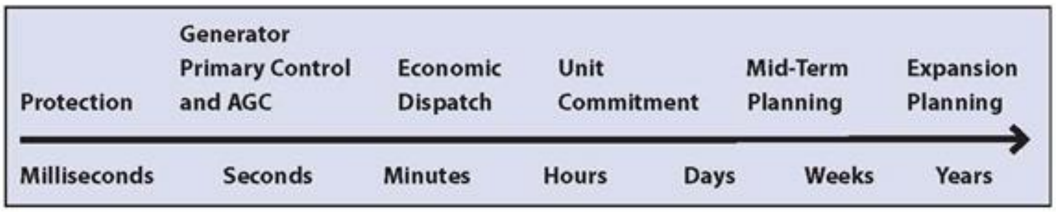


Figure 1: The U.S. grid is the conduit for bulk generation to various end users. The traditional configuration of the grid represented above is increasingly challenged by new forms of distributed generation and demand response.

This complex mix of new economic realities, changing resource mix, and the U.S. electrical system's technological makeup and regulatory structure poses challenges – or at least questions – to the model that has driven electricity generation, transmission, and distribution for the better part of a century. The centralized mode of planning that has been essential to management of the grid will remain critical to ensuring its smooth function. However, this process will need to account for millions of new generation and efficiency sources that are increasingly material to the TS&D system. This shift will have important region-specific characteristics, but in all cases, substantial planning will be necessary to meet needs on the scale of milliseconds, minutes, hours, years, and decades into the future (See Figure 2).

Some of the dominant trends that will influence this planning include the retirement of existing resources due to age and regulation; the buildout of new resources such as natural gas and renewables (some of them intermittent); and changes in the evolution of electricity growth curves driven by slower economic growth, fundamental shifts in patterns for energy use, and the decoupling of economic growth and electricity demand.



Source: I. J. Perez-Arriaga, H. Rudnick, and M. Rivier, "Electric Energy Systems: An Overview," in *Electric Energy Systems: Analysis and Operation*, eds. A. Gomez-Exposito, A. Conejo, and C. Canizares (Boca Raton, FL: CRC Press, 2008), 60.

Note: AGC = automatic generation control.

Figure 2. Transmission operation and planning functions are shown by timescale (copied from MIT Grid report, pg. 35).

The purpose of this memo is to briefly explain some of the existing U.S. electrical TS&D system's regulatory and business characteristics and highlight some of the systemic drivers of change that will affect operations and planning of the United States' electrical infrastructure over the coming decades. The objective is to solicit input from stakeholders outside the U.S. government on the QER's policy process.

2. How the U.S. electricity system works

At its beginning, the electric power industry was mostly a local phenomenon, with generation, transmission, and distribution built to serve a relatively small, geographically constrained set of customers. But as technology improved, the cost of electricity was found to be potentially lower when the system was administered as a regional monopoly. One element of this cost savings came from allowing power plants to be operated under the concept of economic dispatch, wherein generation resources were deployed on the basis of operating costs (subject to reliability requirements).[1] Provided that monopoly pricing power was not abused, monopolies were the most economically efficient means to deliver power to consumers. Accordingly, state governments allowed private electric companies to exist as state-regulated monopolies, with legal provisions in almost all states that allow for publicly owned and cooperatively owned electric utilities regulated by locally elected or appointed boards. This vertically integrated structure was the origin of the modern electrical business model and regulatory compact.

Today, the U.S. transmission and distribution system is a vast complex of interlocked machines, wires, and regulations. This dynamic web must be continually and actively managed to maintain system reliability and functionality. Every year, the U.S. grid delivers 3,857 terawatt hours (TWh)[2] of electrical energy from electric power generators to 144 million residential, commercial, and industrial customers. This is accomplished via 283,000 miles of high-voltage transmission wires, 70,000 substations, and

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[1] For example, very large transmission lines were built between the Pacific Northwest and California in the 1960s to allow seasonal-based exchanges of electricity between the two regions when electricity generation is cheaper in one region.

[2] DOE, Energy Information Administration (EIA), "Annual Energy Outlook 2014" (May 7, 2014), http://www.eia.gov/forecasts/aeo/MT_electric.cfm.

2.2 million miles[3] of local distribution circuits.[4] Together with its electric generation component, the grid is sometimes referred to as the world's largest machine. This "machine" provides the fundamental underpinnings of America's national economy, and it is changing in ways that fundamentally challenge established modes of operation.

The continental U.S. grid comprises three major regional interconnections

America's network of transmission lines is embedded in three electrical interconnections, one for the Western United States, Eastern Canada, and parts of Northern Mexico (the Western Interconnection); one for the Eastern United States and Eastern Canada (the Eastern Interconnection); and one that covers most of Texas (the Electricity Reliability Council of Texas Interconnection, or ERCOT) (see Figure 3). While there are small links between interconnections, historical attempts to link the Western and Eastern Interconnections have hitherto been abandoned because of possible adverse impacts on reliability.[5] Hawaii and Alaska operate off of power systems that are substantially different from these because of the unique geography and load distributions within these non-contiguous U.S. states.

[3] Harris Williams & Co., "Transmission & Distribution Infrastructure" (Summer 2010), http://www.harriswilliams.com/sites/default/files/industry_reports/final%20TD.pdf.

[4] Here, a "customer" is defined as the electricity consumed at one electric meter. Thus a customer may be a large factory, a commercial establishment, or a residence. A rough rule of thumb is that each residential electric meter serves 2.5 people.

[5] Since the 1960s, technology and control strategies for large transmission networks have improved to the extent that transmission planners are discussing the conceptual building of substantial links between the interconnections and transmission lines. For example, the Tres Amigas project is trying to find tenants for a converter station in Clovis, New Mexico, that would allow flows between all three interconnections.

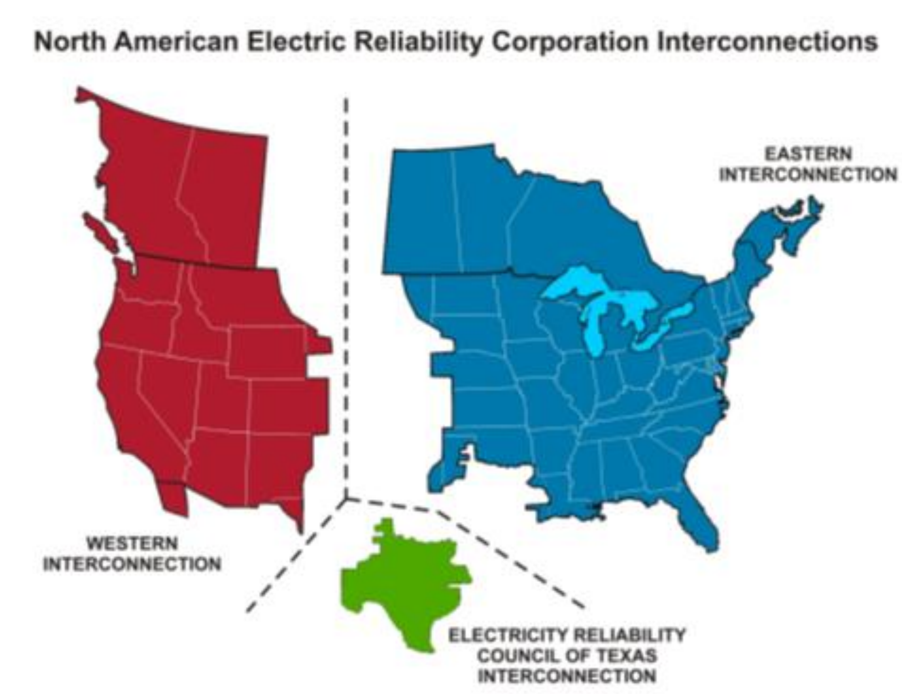

Figure 3. The U.S. network of transmission lines comprises three electrical interconnections: the Western Interconnection, the Eastern Interconnection, and ERCOT.

Changes may be required in distribution

Emerging technologies on the distribution grid (whether digital communications, sensors, control systems, digital "smart" meters, distributed energy resources, greater customer engagement, etc.) present both technical and policy challenges and opportunities for the delivery of energy services.

For example, significant changes at the distribution level in planning, operations, rate structures, and regulatory oversight models may be required in those regions that see significant uptake of distributed generation (whether solar or gas-fired). Today, most distribution networks are planned and built to accommodate one-way flows of electricity: from large-scale generation through transmission lines through distribution lines to customers (see Figure 1). Future distribution networks will need to be designed to handle two-way electricity flows while maintaining reliability. Already some areas (e.g., Hawaii) are confronting such issues at a material scale as significant amounts of distributed generation come on line. There are diverse viewpoints regarding how costs ought to be allocated and who should pay for the services the grid provides to the distributed generation owners.

At the same time, the deployment of new telecommunications and information technologies for distribution and transmission offers the possibility to provide more customer services, and maintain or improve operations and reliability. The greater use of these technologies also presents cybersecurity and privacy questions. The electric power industry, their regulators, and the federal government are all engaged in efforts to address these challenges.

Such changes have injected uncertainties into a utility business model that has typically relied on high utilization, steady economic returns, and long payback horizons.

3. Massive investments in the grid will continue

The grid delivers electricity to end-use customers through a diverse system of over 3,200 privately, publicly, and cooperatively owned electric utilities.[6] In addition to these, there are wholesale-only entities that generate or trade electricity, operate power plants, and/or operate the transmission system itself. Because these systems are interconnected, they require a complex system of state and federal regulatory oversight to ensure function, resilience, and reliability. A 2008 estimate suggested that investment needs for electric infrastructure could be as high as $2 trillion between 2008 and 2030, with $298 billion directed toward transmission and $582 billion toward distribution systems.[7] Such predictions are necessarily speculative, but in the past six years, uncertainty surrounding investment requirements for the U.S. grid has only grown. Some of the factors that have contributed to this uncertainty include lower economic growth, state energy efficiency mandates on utilities, increasing use of demand response, and increasing implementation of distributed generation.

Some of these changes are compounding. On one side, more variable generation (wind and solar) is being deployed. On the other, facilities that provide "ancillary" services used to maintain bulk power grid reliability are being retired. For instance, the grid operates at 60 hertz, which simply means that dynamos must spin 60 times a minute to balance load and demand. Any substantial variation could lead to blackouts or damage critical components of the generation, transmission, and distribution system. Currently the inertia for "frequency balancing" within this system is provided by large steam (typically coal) plants and heavy industrial loads.[8] Higher penetrations of non-synchronous generators, such as wind and solar, coupled with loss of industrial loads, complicates this equation. At the same time, customer expectations for reliability and quality of electrical power are becoming culturally engrained through increased use of digital devices.

Other technological trends are helping to meet new demands of the electrical system. Better digital information technologies (i.e., the so-called "smart grid") can provide some of the tools to better integrate these disparate sources of energy into a reliable electrical system, improve grid operations, and expand customer service opportunities. Some other methods used include changes in rules and reliability standards underway by the North American Electric Reliability Corporation (NERC) and the use of more flexible generation and load. Electricity storage – long considered the "holy grail" of grid management technology – may also be seeing advances that could expand its deployment from the current limited uses.

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[6] DOE, EIA, "Electric Power Annual 2012," Form EIA-861 (December 2013).
[7] Brattle Group, "Transforming America's Power Industry: The Investment Challenge," produced for the Edison Electric Institute (2008).
[8] North American Electric Reliability Corporation (NERC), "Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Solutions" (March 2011).

4. Extensive planning for new construction

The difficulty of linking America's interconnections into one cohesive unit is just one example of the complexity of managing the grid. Because of this complexity, new construction requires extensive planning. The nature of that planning process is partially defined by the ownership structure of the local utility or operator.

Electrical TS&D ownership comes in many flavors. In 2014, the dominant model for transmission was still the vertically integrated investor-owned utility. But groups of smaller public power utilities and rural electric cooperatives can also develop and own transmission through creation of a "joint action agency" or a "generation and transmission cooperative," respectively. The federal government can develop and own transmission projects through the Bonneville Power Administration, Western Area Power Administration, and the Southwestern Power Administration. A more recent creation of the last decade or so are merchant transmission companies who develop and own transmission, but own no distribution or often generation resources.[9] These companies often seek to build long-distance transmission lines that traverse more than one state.

One commonality to all of these entities is that they are all subject to extensive regulatory approval processes should they want to develop and site new transmission projects. Again, ownership has a direct effect on the regulatory regime applied to various transmission projects. For instance, publicly-owned electric utilities (including the federal Power Marketing Administrations [PMAs]), and almost all rural electric cooperatives, are generally not subject to FERC's jurisdiction – which means they are not subject to FERC's planning and cost allocation rules so long as they act alone. However, when cooperatives and public power utilities cooperate with FERC-regulated facilities, they may also come under FERC's jurisdiction.[10]

After a pause, transmission has expanded since 2000

In the 1990s, there was a hiatus in transmission construction in the United States. However, the 2000's saw a significant increase in both planning and construction (see Figure 4).[11] That buildout continues today.

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[9] Examples include American Transmission Company, International Transmission Company, Transmission Developers Inc., LS Power, Transource Energy, and Clean Line Energy Partners, among others.
[10] Federal Power Act.
[11] The Edison Electric Institute has tracked transmission spending by its member utilities with an annual published survey since 2007. "Transmission Projects at a Glance" (March 2014) is the latest, http://www.eei.org/issuesandpolicy/transmission/Documents/Trans_Project_lowres_bookmarked.pdf. More recently, a five-fold increase in new electricity transmission from 1997 to 2012 is documented in "Investment in electricity transmission infrastructure shows steady increase", Today in Energy, Aug. 26, 2014, Energy Information Administration, http://www.eia.gov/todayinenergy/detail.cfm?id=17711

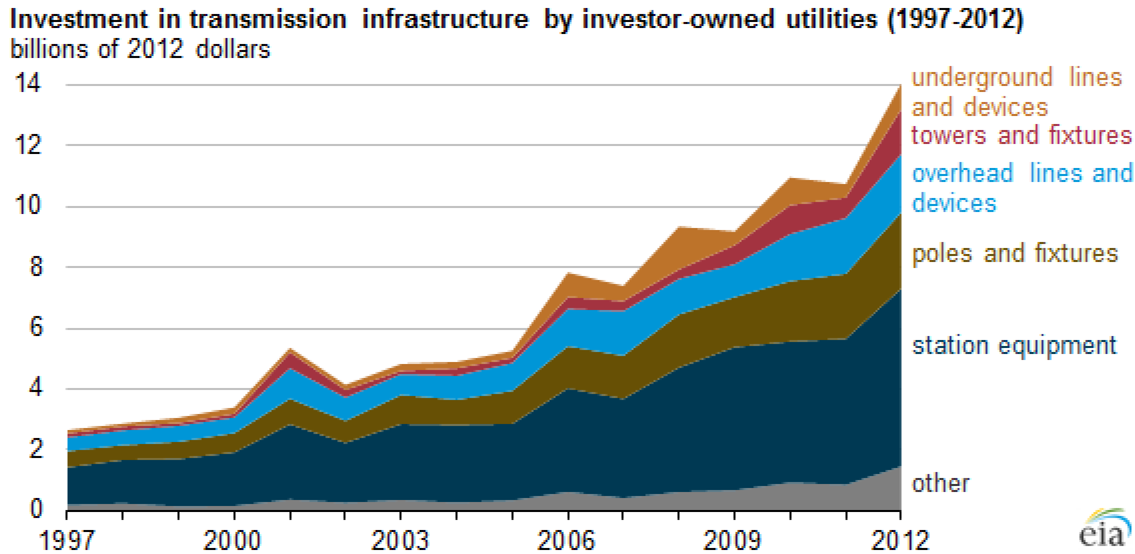

Figure 4. Source: Today in Energy, August 26, 2014, U.S. Energy Information Administration, based on Federal Energy Regulatory Commission Financial Reports, as accessed by Ventyx Velocity Suite.

Existing generation is some areas of the country is being affected by recent U.S. Environmental Protection Agency (EPA) air and water rules; these areas are seeing construction of shorter transmission lines, as well as other measures, to maintain reliability. Still, the economic, resource and regulatory uncertainties surrounding this complex process can remain a challenge for the industry.

Recent years have seen a number of cancelations or delays of transmission projects for reasons ranging from the 2008 economic recession, to increased energy efficiency in load centers, to growth in distributed generation. Expanding shale gas resources has also led to natural gas power plants being built closer to load centers, thus reducing the need for transmission lines.[12] Many discussions regarding expanding access to renewable energy resources in the United States coalesce around the difficulty of siting and building long-distance, high-voltage electrical transmission lines from the resource base to demand centers. Though in some cases it is hard for remote resources to compete with local resources – which reduces the need for long transmission lines. In practice, building even short transmission lines can at times be difficult. This is particularly true if lines cross over sensitive federal lands.

Planning, siting, and cost allocation are steps in building new transmission

Planning, siting, and cost allocation (see Figure 5) are the three major regulatory elements of building new transmission. Transmission projects can take more than a decade to reach operation. But once built, they can provide a steady and reliable return on equity for decades. A number of cost-recovery schemes are available, but the incentive to build transmission rests on the fact that, relative to many other

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[12] DOE, "Transmission Constraints and Congestion in the Western and Eastern Interconnections, 2009-2012," (January 2014), http://energy.gov/sites/prod/files/2014/02/f7/TransConstraintsCongestion-01-23-2014%20.pdf .

investments, transmission assets can provide long-term and stable returns – something that cannot be ensured in a dynamic market and technological environment.[13]

Traditionally, there have been two varieties of line upgrades: reliability upgrades and economic upgrades. In practice, new lines can be proposed by incumbent transmission owners, typically electric utilities, or by newer market entrants that are transmission-only companies (sometimes called "transcos" or "merchant transmission"). If done for reliability purposes, a new line is called a "reliability-upgrade" project. "Economic upgrades" are projects that connect new generation to load centers. Another type of "economic upgrade" is a transmission project that reduces power system costs. Such lines are typically built to ease or avoid congestion charges. [14]

A transmission line may also be justified as a mix of these two categories. Because of the nature of electricity flows on a bulk power network, compartmentalizing the benefits between economic and reliability improvements can be difficult.[15]

The process of building a new line can be long. The first stage entails a local FERC-appointed planning authority ensuring that the new transmission projects will not lead to systemic operational problems for the existing grid that might compromise reliability. As part of this, the planning authority must conduct a system impact study.[16] These studies employ computer modeling to analyze whether a

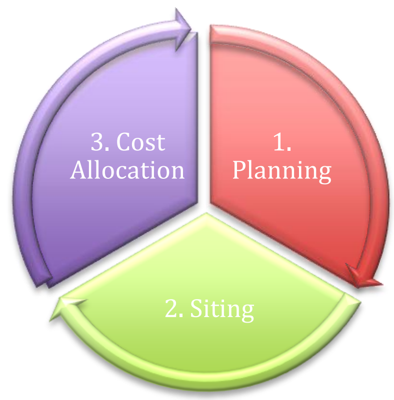

Figure 5. Planning, siting, and cost allocation are steps in building new transmission.

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[13] As with any business, utilities and others who build transmission will adapt their corporate strategies in accordance with likely capital investments based on market trends (as well as governmental policies). For example, American Electric Power, one of the nation's largest electric utilities and thus a large owner of both generation and transmission, now has a strategy of not building new power plants, actually retiring many power plants, and expanding its transmission network, which is already 39,000 miles and goes through 11 states. "The company has developed a series of transmission projects that will provide reliable financial returns at a time when the industry's main sources of income are flat." See Dan Gearino, "AEP's Power Play: De-Emphasizing Electricity Plants," *Columbus Dispatch* (December 29, 2013).

[14] Navigant Consulting, "Transmission Planning White Paper," produced for the Eastern Interconnection States Planning Council (EISPC) and the National Association of Regulatory Utility Commissioners (NARUC) (January 2014), 26.

[15] Ibid.

[16] Lines proposed by newer transmission-only ("merchant") developers may not actually request that the local transmission planning authority conduct a system impact study, per se. For example, the developers of the proposed Northern Pass line, a 187-mile 1200-megawatt line from Quebec to New Hampshire, is an "elective" project (i.e., an economic upgrade line to connect new generation to load) and under Independent System Operator – New England (ISO-NE) rules can perform its own system impact study -- which occurred but based on ISO-NE's direction and review. Nevertheless, ISO-NE approved in January 2014, from a reliability standpoint, the project for interconnection into the New England grid.

proposed line is likely to disrupt the grid or lead to any violations of NERC reliability standards.[17] Each project's costs and benefits are also evaluated together with forecasted changes in regional electricity demand and supply. During this process, a planning authority may consider alternatives to the proposed line – including alternative transmission, new generation, and demand side management. These studies are later considered by the various regulatory bodies as part of their decisions. Approval must then be obtained from the various state, and often federal if a federal land or water is involved, siting authorities. Buyers and sellers of electricity along the proposed line must be lined up, as well as financing, and FERC must approve associated tariffs.

Many short transmission projects have always and will continue to be built within a state. But a March 2014 survey of utilities by the Edison Electric Institute showed that 43 percent of proposed spending for new lines between 2014 and 2024 will go to projects that span two or more states.[18]

Impact of FERC Order No. 1000 on transmission planning

FERC, under the Federal Power Act of 1935, as amended, regulates interstate commerce of electricity and thus transmission for entities that come under its jurisdiction, whether a transmission line crosses a state boundary or not.[19] Courts have upheld FERC's authority to issue orders that dictate the process of how. These orders have a substantial influence on the practice of transmission planning. FERC's most significant recent rulemaking was Order 1000 (2011), which required regional transmission planning to be coordinated by NERC-registered regional transmission planning authorities.[20]

FERC Order 1000 represented a fundamental shift in transmission planning.[21] Regional and independent transmission organizations (RTOs and ISOs) are large enough that they can file single plans with FERC covering their entire footprint without consulting neighboring planning authorities. But FERC Order 1000 requires that smaller planning authorities, particularly outside RTOs and ISOs, consult with neighboring planning authorities to prepare joint plans and file those along with their own Order 1000 filing with FERC.

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[17] NERC, with federal government oversight by FERC, per the Energy Policy Act of 2005, develops and enforces mandatory reliability standards for the bulk electric power system.

[18] EEI, "Transmission Projects: At a Glance," (March 2014), http://www.eei.org/issuesandpolicy/transmission/Documents/Trans_Project_lowres_bookmarked.pdf.

[19] States also have jurisdiction over transmission, most notably over the siting of transmission lines on either private or state-owned land. FERC does have "backstop" siting authority over states given it, in certain circumstances, by the Energy Policy Act of 2005, but court decisions have made the practicality of that authority largely moot to date.

[20] FERC, Order No. 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities (July 2011), http://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf.

[21] FERC Order 1000 survived a major court challenge with a positive August 2014 decision by the D.C. Circuit Court of Appeals. FERC Chair Cheryl LaFleur comments on the significance of the rule: "Order 1000 is really probably the largest policy action that the commission's taken in the four years since I've been on it, and it really contemplated that the nation's going to need a lot of new transmission investment and set up a structure that required that that transmission be planned and cost-allocated on a regional basis." Source: "Commission Chair LaFleur talks carbon rule challenges, reliability, Order 1000, Senate politics", E&E TV On Point, September 2, 2014.

5. Storage, a potentially transformational technology

Additional changes may accelerate these trends. Perhaps foremost among these is the possible emergence of economic large-scale battery storage.

An electricity system wherein a significant proportion of generation capacity is backed up by readily dispatchable storage would be a dramatic departure from the status quo. Traditionally, energy storage has taken place in the context of fuel stockpiling, hydro reserves, pumped storage (also hydro) together with some other niche mechanisms. Today, large scale battery storage in various modalities may be on the cusp of commerciality and a breakthrough in the economics of batteries is a real possibility. Combined with the dramatic increase in wind and solar generation that could benefit from economic storage, this could precipitate an even more dramatic set of changes within the space than we are witnessing today.

The United States has about 1,200 gigawatts (GW) of installed generation capacity, and only 21.1 of grid-connected, utility-scale (>1MW) storage systems.[22] Of that existing capacity 96% is associated with pumped storage hydroelectric – where water is pumped to higher elevations during periods of low demand and run through turbines to generate electricity during high demand. Globally, such pumped hydro storage accounts for approximately 99% of deployed utility-scale storage in operation.[23] Pumped hydro storage requires specific local favorable geography, thus limiting its widescale use. However, the last few years has seen a significant uptick in requests for pumped storage licenses by FERC. [24]

Today, policy focus on and expanded deployment of intermittent energy sources (e.g.wind and solar) are driving an expansion in the deployment of energy storage. Lithium ion batteries are being sold and piloted for home-, facility- and neighborhood-scale use, and should lithium-ion battery prices continue to drop and distributed generation becomes more commonplace this uptake is may accelerate.[25]

Other types of storage are reaching commerciality. Molten salt storage uses heat (often from concentrated solar power) to store utility-scale amounts of energy. In the past years, several CSP plants with such storage capacity have come online, including the Abengoa Solana project with six hours of molten salt storage in Gila, AZ, and the Crescent Dunes Solar Energy Plant near Tonopah, Nevada with ten hours of storage. Additional storage options include: flywheels (that use the momentum of spinning disks or drums to store energy); flow batteries (large scale batteries); air pressure-based systems; and rail cars that are

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[22] DOE, EIA, "Electric Power Annual 2012," Annual Electric Generator Report, Form EIA-860, (December 2013), http://www.eia.gov/electricity/annual/html/epa_04_03.html.
[23] Thomas W. Overton, "The Year Energy Storage Hit Its Stride," Power Magazine, Vol. 158, No. 5, (May 2014).
[24] AFERC pumped storage page includes periodic updates on licensing applications that show over time an uptick. http://www.ferc.gov/industries/hydropower/gen-info/licensing/pump-storage.asp

[25] Justin Gerdes, "Here's why the forecast for microgrids looks this sunny," Green Biz Online, (July 2014), http://www.greenbiz.com/blog/2014/07/07/power-microgrids-unfolding-now.

driven uphill by electric motors and then back down to generate electricity during periods of high demand.

Various states may role in expanding U.S. demand for electricity storage. In particular, California has mandated 1.3 GW of non-pumped hydro storage be installed by 2020.

6. Business models for regulated utilities, and their regulation, may change

Electric utilities that distribute electricity to customers, whether they own generation and transmission lines or not, may in some areas of the U.S. be facing pressures on their traditional business model of universal service of electricity to all that is financed by steadily and predictable increased sales and thus revenue.[26]

State public utility commissions for the investor-owned utilities they oversee, or local appointed boards for publicly- and cooperatively-owned utilities who largely regulate them, may correspondingly have to consider their traditional "cost-of-service" form of regulation that works for that long-standing business model.

Trends of declining sales or low load growth, increasing self-generation by customers driven by both technological change and policies, and yet increased investment needed to maintain and continue updating the nation's electricity transmission and distribution network, as well as the capital expense needs stemming from with large changes in generation driven by state and federal energy and environmental policies and laws, all cause some to question whether current business models and the traditional cost-of-service regulation for regulated electric utilities are still appropriate. Others say they are, but need to adapt, or not.

The question is important for electricity ratepayers, as well as our economy, as someone must continue to pay for the cost of maintaining and continuously improving the grid's extensive transmission and distribution network. If sales and thus utility revenue stay down, the cost of higher access to capital that may result could put an upward pressure on electricity bills. A rough analogy being cellphones and traditional landline telephone service, but with electricity there is no currently widespread economic storage, so even those who are installing distributed generation need the electric grid for backup when their own generation is not available.

[26] The emphasis is on regulated utilities who directly serve customers, for any negative financial health may impact directly their customers in terms of their electric bill. In contrast, holding companies that are over some investor-owned utilities, not being themselves subject to state regulation, are free to invest shareholder funds to adapt to changing market conditions. Holding companies can do and change their investments, all the time, including in electric industry or non-utility assets to counter any expected or real loss in their various company holdings, including their regulated utility subsidiaries. Business models for utility holding companies are not relevant for this discussion.

The question is being raised not just for state-regulated investor-owned utilities, but those that are locally regulated as publicly- and cooperatively-owned electric utilities. While not organized to earn a profit for shareholders as investor-owned utilities are, nevertheless, low or declining sales growth could still similarly impact customers of publicly- and cooperatively-owned electric utilities under the same mechanism of the need to maintain investment in the grid while the customer base to pay for it shrinks.

There is now a considerable amount of research and advocacy aimed at alternative utility business models. Utility industry meetings, through their national trade associations, as well as meetings of the National Association of Regulatory Utility Commissioners (NARUC), regularly feature panels on the utility business model issue.[27]

Some view existing business models and their traditional cost-of-service regulation as significant challenges to certain types of clean energy, such as distributed solar and energy efficiency. Electric utilities express concern about keeping revenue sufficiency, maintaining reliability by not underinvesting in infrastructure, having continued access to affordable capital and good credit ratings, and managing regulatory uncertainty risk.

There are some alternative business models being discussed, such as, among others, the energy services concept[28] or the local utility as a grid integrator. Still others propose that local "distribution service organizations", similar in concept to a regional transmission operator but at the local level, be created.

For regulation, performance-based ratemaking, among others, is proposed to replace cost-of-service regulation. The UK regulator of Ofgem is implementing a performance-based regulatory scheme. However, US attempts by U.S. state public utility commissions to adapt parts of performance-based ratemaking since the 1980s has had mixed results.

None of these changes, if they do occur, will happen overnight. The U.S. utility industry is quite diverse with 51 public regulatory commissions and numerous local and elected boards for public power and electric cooperatives in addition to regional differences on whether the business model issue is even germane.

[27] One of many examples is "Utility Business Models in a Low Load Growth/High DG Future", Charles Goldman, Andy Satchwell, and Peter Cappers, Lawrence Berkeley National Laboratory, NARUC Summer Committee Meeting, Denver, CO, July 23, 2013.
http://www.narucmeetings.org/Presentations/Goldman_Utility%20Business%20Models%20of%20Future%20NARUC_v7short_20130703.pdf

[28] "IEI Breakfast Briefing - The Power Grid's Evolution into an Energy Services Platform", a briefing by investor-owned utilities sponsored by the Edison Foundation's Institute for Electric Innovation (IEI) on July 15, 2014 during the NARUC 2014 Summer Committee Meeting.

In terms of timing, the analogy may be to the discussions that began in many states and at the Federal level in the 1980s on electric industry restructuring that saw a number of states enact various restructuring laws in the late 1990s. Other states in the west outside of California and the southeast did not pass such laws.

Key Questions

Significant changes will be required to meet the transformational challenges posed by our evolving electricity system. DOE is seeking public input on key questions relating to electricity transmission, storage and distribution system including:

1. Where is the nation's electricity TS&D system headed?
2. What kind of policies and planning can encourage reduction of transmission and distribution system vulnerabilities (e.g., cyber/physical attacks, weather, fire) on near-, medium- and long-term horizons?
3. How can the federal government remove limitations/obstacles to siting needed transmission lines?
4. How will changes in the resource portfolio affect transmission needs, operation, and reliability?
5. Are regulations needed to incentivize desirable characteristics for the future grid?
6. What is the future role for Canadian electricity imports, and how will they affect generation and transmission needs in the United States?
7. What limits the value that distributed energy resources provide to the electric system? Can these challenges be mitigated? If so, how?
8. What are the challenges/threats to the existing regulated utility business model and its regulatory system? How do they rank in significance?
9. Should how distribution is compensated be changed in a different mix of electricity sales, services provided, fixed charges or some combination thereof?
10. Is there a forcing function for changes in the regulated utility business model (e.g., regulation, technology financial markets, etc.)?
11. Should the regulatory compact be redefined to accommodate any different future role of the utility, and if so, how should the benefits of the grid and that of distributed generation be addressed while at the same time ensuring equity among ratepayers?
12. How, will, or should the future utility need to coordinate transactive customers, distributed generation, and microgrids should they become more commonplace?
13. Can storage be incorporated into the system to maximize its benefits? If so, how?
14. How important is it to develop a national architecture for how all the components of the electrical system will function together?
15. Should the federal government develop a sectoral roadmap for the electricity sector?
16. What are the respective roles for industry and government in addressing cyber security issues related to an increasingly complex generation system?

17. What changes to the electricity TS&D system would help enable lower-carbon, more energy efficient energy production and use?
18. What technologies or policies would reduce direct energy loss from the electricity TS&D system?