U.S. Department of Energy
Washington, DC 20585

Date: **July 7, 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**

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 Friday, July 11, 2014, at 9:00 a.m. in the Lewis & Clark College Templeton Campus Center's Stamm Dining Room in Portland Oregon, 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 Western United States. 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 2:15 p.m. Written comments can be submitted to QERcomments@hq.doe.gov. The session will also be webcast; at www.energy.gov/live.

The Secretariat will also convene a meeting in New Jersey (date and location TBD) to discuss electricity TS&D issues in the Eastern United States. Related QER stakeholder meetings will include gas-electric interdependence (Denver, CO), infrastructure siting (Cheyenne, WY), rural energy (Iowa), and state, local and tribal issues (Santa Fe, NM). More information on these 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 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.

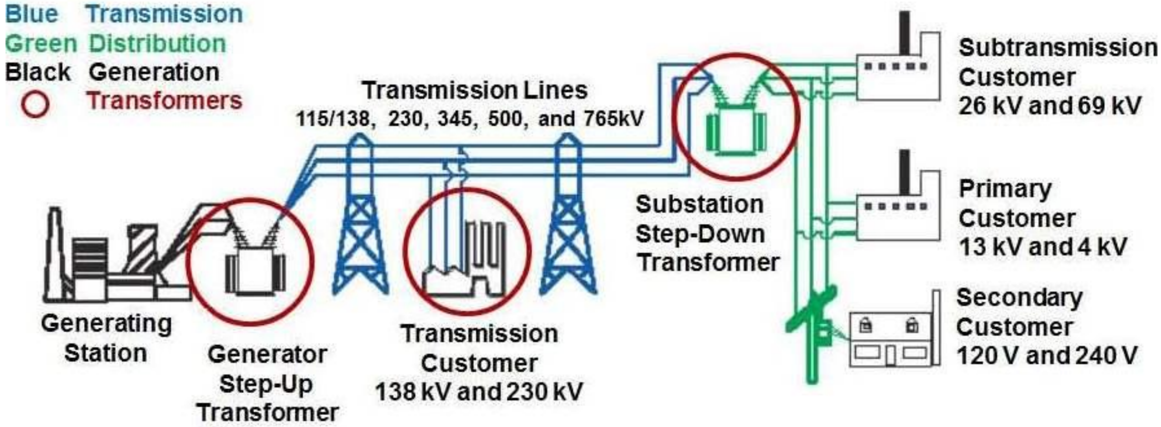
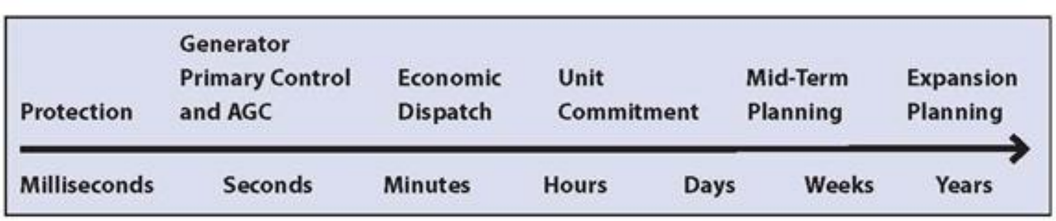


Figure 1: The U.S. grid is the conduit for bulk generation to various end users. The traditional configuration of the grid represented above is increasingly challenged by new forms of distributed generation and demand response.

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 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.

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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.
[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.

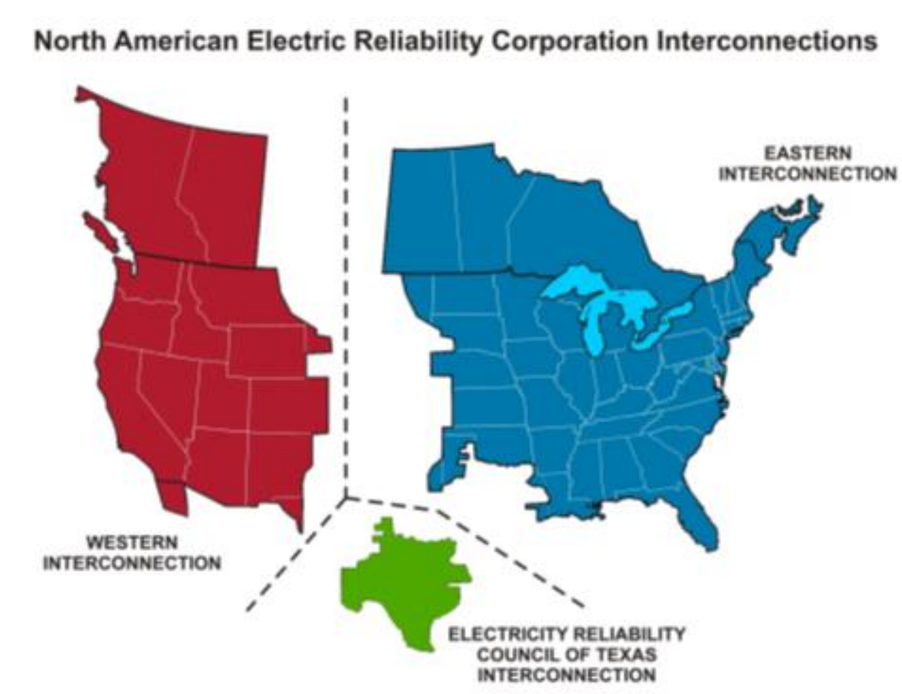

Figure 3. The U.S. network of transmission lines comprises three electrical interconnections: the Western Interconnection, the Eastern Interconnection, and ERCOT.

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, Western 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.

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.

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[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.

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

[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).

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 integrate these disparate sources of energy into a reliable electrical system, improve grid operations, and expand customer service opportunities.[9] Some other methods used include changes in rules and reliability standards by the Federal Energy Regulatory Commission (FERC) and 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.

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 electricity TS&D 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. Finally, the federal government can develop and own transmission projects through the Bonneville Power Administration, Western Area Power Administration, and the Southwest Power Administration. Merchant transmission companies own transmission but no generation resources,[10] and 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 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

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[8] North American Electric Reliability Corporation (NERC), "Ancillary Service and Balancing Authority Area Solutions to Integrate Variable Solutions" (March 2011).

[9] Electricity Advisory Committee, "Smart Grid Outreach and Education Strategy: The Next Steps" (October 2012), http://energy.gov/sites/prod/files/EAC%20Paper%20-%20Smart%20Grid%20Outreach%20and%20Communication%20Strategy%20-%20The%20Next%20Steps%20-%20Final%20-%208%20Nov%202012%20.pdf.

[10] Examples include American Transmission Company, International Transmission Company, and Clean Line Energy Partners.

public power utilities cooperate with FERC-regulated facilities, they may also come under FERC's jurisdiction.[11]

After a pause, transmission has expanded since 2000

In the 1990s, there was a hiatus in transmission construction in the United States. However, the 2000s saw a significant increase in both planning and construction.[12] That bailout continues today. 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.[13] 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.

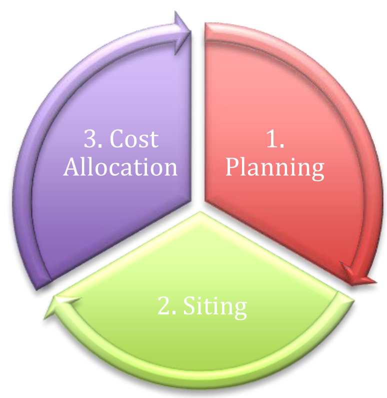

Figure 4. Planning, siting, and cost allocation are steps in building new transmission.

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

Planning, siting, and cost allocation (see Figure 4) 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

[11] Federal Power Act.

[12] The Edison Electric Institute has tracked transmission spending by its member utilities with an annual published survey since 2007. Edison Electric Institute (EEI), "Transmission" (2014), http://www.eei.org/issuesandpolicy/transmission/Pages/default.aspx; and EEI, "Transmission Projects at a Glance" (March 2014), http://www.eei.org/issuesandpolicy/transmission/Documents/Trans_Project_lowres_bookmarked.pdf.

[13] 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.[14]

Traditionally, there have been two varieties of line upgrades: reliability upgrades and economic upgrades. In practice, new lines can be proposed by companies or planning authorities. 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. [15]

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.[16]

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.[17] These studies employ computer modeling to analyze whether a proposed line is likely to disrupt the grid or lead to any violations of NERC reliability standards.[18] 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, 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.

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[14] 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).

[15] 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.

[16] Ibid.

[17] 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 the project for interconnection into the New England grid.

[18] 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.

Over the coming decade, the federal role in new transmission construction is likely to be significant. 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 – which would place them under federal jurisdiction.[19]

Impact of FERC Order No. 1000 on transmission planning

FERC is responsible for regulating transmission of most interstate lines and throughout much of the U.S. wholesale electricity market. FERC's "orders" dictate how transmission planning must be carried out by entities subject to its jurisdiction. 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 consult with neighboring planning authorities to and prepare joint plans.

5. Storage, a potentially transformational technology

Additional changes may accelerate these trends. Perhaps foremost among these is the possible emergence of 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 drops in the cost of renewable energy generation, 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

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[19] EEI, "Transmission Projects: At a Glance," (March 2014), http://www.eei.org/issuesandpolicy/transmission/Documents/Trans_Project_lowres_bookmarked.pdf.
[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 is currently under multiple court challenges and thus is not yet settled. It was also covered in a December 5, 2013, oversight hearing of FERC by the House Committee on Energy and Commerce Subcommittee on Energy and Power.
[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.

hydro storage accounts for approximately 99% of deployed utility-scale storage in operation.[23] However, pumped hydro storage requires significant amounts of water as well as topography that is appropriate to its construction – and it can generally only be deployed at extremely large scales. These last two factors in particular are a challenge to the extensibility of pumped hydro.

Today, policy focus on and expanded deployment of intermittent energy sources (e.g. renewables) 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 as lithium-ion battery prices continue to drop and distributed generation becomes more commonplace this uptake is likely to accelerate.[24]

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, a number of CSP plants with such storage capacity have come online, including the Gemasolar CSP plant near Seville Spain, and the Crescent Dunes Solar Energy Plant near Tonopah, Nevada. Additional storage options include: fly wheels (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 driven uphill by electric motors and then back down to generate electricity during periods of high demand.

Various states have taken a pro-active 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.

[23] Thomas W. Overton, "The Year Energy Storage Hit Its Stride," Power Magazine, Vol. 158, No. 5, (May 2014).
[24] 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.

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 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. Should the regulatory compact be redefined to accommodate the future role of the utility, and if so, how should the benefits of the grid and that of distributed generation be addressed?
9. Will the future utility need to coordinate transactive customers, distributed generation, and microgrids?
10. Can storage be incorporated into the system to maximize its benefits? If so, how?
11. Should transmission and distribution be compensated in electricity sales, services provided, or some combination thereof?
12. Is there a forcing function for changes in the regulated utility business model (e.g., regulation, technology financial markets, etc.)?
13. How important is it to develop a national architecture for how all the components of the electrical system will function together?
14. Should the federal government develop a sectoral roadmap for the electricity sector?
15. What are the respective roles for industry and government in addressing cyber security issues related to an increasingly complex generation system?
16. What changes to the electricity TS&D system would help enable lower-carbon, more energy efficient energy production and use?
17. What technologies or policies would reduce direct energy loss from the electricity TS&D system?