Electricity Regulation USA 2022

Robert A. James*

Pillsbury Winthrop Shaw Pittman LLP

1 Policy and law

What is the government policy for the electricity sector?

No single government body sets policy for the electricity sector. The federal agencies, which regulate wholesale and interstate transmission markets, generally favors policies that foster competition in that sector. The competition reforms that transformed the US electricity sector in the 1990s and 2000s represent the latest chapter in many decades of restructuring, deregulation and regulatory reforms—transformations that have affected many sectors of the economy historically subject to price regulation. Meanwhile, state governments supplement competition policies with price regulation of retail sales and local distribution built on traditional principles of natural monopolies and public utility regulation.

How is responsibility divided between the federal government and the states?

US Congress

The Energy Policy Act of 2005 (EPAct 2005) was the most significant change in US energy policy since the Federal Power Act of 1935 (FPA) and the Natural Gas Act of 1938 (NGA). EPAct 2005 granted the Federal Energy Regulatory Commission (FERC) the authority to:

- Regulate the transmission and wholesale sale of electricity in interstate commerce;
- Review certain mergers and acquisitions and corporate transactions by electricity companies;
- Review siting applications for electric transmission projects under certain limited circumstances;
- Protect the reliability of the high voltage interstate transmission system through mandatory reliability standards;
- Monitor and investigate energy markets;
- Enforce FERC regulatory requirements through imposition of civil penalties and other means; and
- Administer accounting and financial reporting regulations.

Federal administrative agencies

The mission of the US Department of Energy (DOE) is to "ensure America's security and prosperity by addressing its energy, environmental and nuclear challenges through transformative science and technology solutions" (www.energy.gov/mission). FERC, an independent regulatory agency within the DOE, is the principal economic and policy regulator at the federal level for the electric power industry. FERC is charged with implementing, administering, and enforcing most of the provisions of EPAct 2005, FPA, NGA, and other statutes regulating the electric utility industry.

States

State legislatures and agencies center their agendas on the local distribution and retail sale of electricity.

Several states have adopted choice programs intended to introduce competition among retail suppliers. Since the 1990s, several states have required or encouraged vertically integrated utilities to disaggregate into separate generation, transmission, or distribution entities. Additionally, participation in independent system operators (ISOs) or regional transmission organizations (RTOs) was encouraged at the federal level and in many states. The most current data of the American Public Power Association (APPA) most current data indicates that 15 states and the District of Columbia have active retail choice programs for electricity (https://www.publicpower.org/system/files/documents/Retail-Electric-Rates-in-Regulated-Deregulated-States-2019-update.pdf).

Once launched, however, some states have delayed or suspended retail choice plans amid concerns that deregulation may not benefit end-use consumers. For example, the New York Public Service Commission cited concern for end-use consumers when it issued sweeping regulations to the state's retail energy market beginning in 2016 (https://www.eia.gov/todayinenergy/detail.php?id=37452).

2 Organization of the market

What is the organizational structure for the generation, transmission, distribution, and sale of power?

According to the latest data compiled from the APPA's 2019 Annual Directory and Statistical Report (https://www.publicpower.org/system/files/documents/2019-Public-Power-Statistical-Report.pdf), the US electric industry is composed of 3,397 electricity providers, including 2,006 publicly owned utilities, 873 cooperatives, 182 investor-owned utilities, 303 power marketers, and ten federal utilities. Together, those utility providers combine to serve 153 million customers, with investor-owned utilities serving the largest share at approximately 68 per cent of the total customers.

The private sector includes traditional utilities that are vertically integrated, generation-owning companies. Additionally, the private sector includes power marketers and transmission or distribution companies. These companies may be privately owned or publicly traded. The public sector consists of municipally-owned utilities, public power districts, state agencies, irrigation districts and other government organizations, and at the federal level, the Tennessee Valley Authority (TVA) and federal power marketing administrations. Rural electric cooperatives, formed by residents, operate in 48 states and comprise about 12 per cent of total US kilowatt-hour sales and revenue (www.nreca.coop/about-electric-cooperatives/co-op-facts-figures/ (updated per https://www.electric.coop/wp-content/uploads/2021/01/Co-op-Facts-and-Figures.pdf).

According to recent statistics of the Energy Information Administration (EIA, part of DOE), as of April 2019, net generation of electric power decreased approximately 1 per cent compared to April 2018 levels.

Generation

The primary energy sources for generating electric power in the US remain fossil fuels such as coal and natural gas, with limited use of oil. Fossil fuels accounted for approximately 62.2 per cent of energy consumption in the US in 2018, and 60.9 per cent in 2019. Natural gas stands as the predominant fossil source, accounting for 34.4 per cent of total net generation in 2018 and 37.5 per cent of total net generation in 2019. Domestic production of crude oil and natural gas has been facilitated by ongoing improvements in extraction technologies and resultant low prices.

Crude oil production has increased sharply since 2008. In 2014, the US produced 8.7 million barrels per day, the highest level of output since reaching a record high (set in 1970) of 9.6 million barrels per day. The EIA, however, predicts that domestic crude oil production will soon level off and eventually decline after 2020. (www.eia.gov/analysis/petroleum/crudetypespdf/crudetypes.pdf) https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=mcrfpus1&f=m; https://www.eia.gov/todayinenergy/detail.php?id=46596). After reaching a peak production in January 2020, US field production of crude oil has steadily declined. EIA largely attributes the current decline to the effects of the coronavirus, but the effect of fracking bans and climate change regulation cannot be understated.

Development of natural gas resources has steadily grown, with a predicted 47 per cent increase in production between 2012 and 2040 (www.eia.gov/beta/aeo/#/?id=13-AEO2015). Driving this growth is the increased use of natural gas as a fuel source for generation; indeed, natural gas has displaced coal as the currently predominant fuel source for generating electric power in the US.

Generation from renewable energy sources, including water, wind, biomass wood and waste, geothermal, solar, and hydroelectric, continues to rise, accounting for over 13 per cent of total US net generation in 2019, with significant growth occurring with small-scale installations such as residential and commercial rooftops.

The EIA has predicted that total US electricity consumption will increase at an average annual rate of 0.8 per cent from 2013 to 2040, but that energy intensity (measured as energy use per person and per dollar of GDP) will actually decline. This forecast assumes that the US population will increase by 0.7 per cent per year and the GDP will increase at an average annual rate of 2.4 per cent per year. The projected decline in energy use per capita reflects anticipated gains in energy efficiency of appliances and vehicles, an economic shift away from energy-intensive manufacturing, and the retirement of less efficient generators.

Power sales

Power marketers do not generate, transmit or distribute electricity, but are classified as public utilities under the FPA because they sell electricity at wholesale. In addition to the numerous privately owned power marketers, there are four federally-owned power marketing administrations that market and sell the power produced at federal hydroelectric and nuclear plants. The APPA reported in its 2019 Annual Directory and Statistical Report that sales of energy to ultimate consumers by power marketers equal 4.5 per cent of total sales. https://www.publicpower.org/system/files/documents/2019-Public-Power-Statistical-Report.pdf

Transmission

The US bulk power transmission system is composed of facilities that are privately, publicly, federally or cooperatively owned. They form parts of three electric networks or power grids: the Eastern Interconnection which stretches from central Canada to the Atlantic coast (excluding Quebec), south to Florida and west to the Rockies (excluding much of Texas); the Western Interconnection, which stretches from western Canada south to Mexico and east over the Rockies to the Great Plains; and the Electric Reliability Council of Texas (ERCOT), which serves the majority of Texas.

Historically, transmission lines owned by private sector companies were part of a vertically integrated utility. In 1996, FERC issued Order No. 888, requiring each public utility subject to FERC's jurisdiction to:

- file an open-access transmission tariff (OATT) declaring the terms and conditions associated with use of its transmission system; and
- functionally unbundle its transmission services from its electricity cables and local distribution services.

FERC has encouraged the development of ISOs and RTOs as independent transmission providers within various regions. These entities are formed by utilities that transfer operational control—but not ownership--of their transmission assets to the ISO or RTO, which is then responsible for operating the regional transmission grid and administering wholesale markets. Today, two-thirds of electricity consumers in the US are served within markets administered by seven ISOs or RTOs: (1) the PJM Interconnection (historically the Pennsylvania-New Jersey-Maryland Interconnection, now serving all or parts of 13 states and the District of Columbia), (2) the Midcontinent ISO, (3) the Southwest Power Pool, (4) the New York ISO, (5) ISO New England, (6) ERCOT and (7) the California ISO. In addition, the California ISO and PacifiCorp have launched the Energy Imbalance Market (EIM), a real-time energy balancing authority with the overall goal of dispatching least-cost energy on a real-time basis across the Western States EIM market. In 2020, utilities in the southeastern US launched a plan for the Southeastern Energy Exchange Market, which would build on bilateral energy exchanges operated throughout the southeast. https://www.utilitydive.com/news/southeastern-utilities-energy-market-proposal-appears-to-be-less-than-it-m/582542/

One of the responsibilities of ISOs and RTOs, as well as other transmission providers, is to maintain the prudent operation of the grid. Pursuant to EPAct 2005, FERC certified the North American Electric Reliability Corporation (NERC) as the nation's Electric Reliability Organization (ERO) to develop and enforce mandatory reliability requirements addressing medium- and long-term reliability concerns, all subject to FERC oversight and enforcement. Today, enforcement of electric reliability standards, including the protection of critical energy infrastructure, is a major focus of the ERO and of FERC, which may impose penalties of up to US$1 million a day on transmission or generation owners and operators and certain other regulated entities for a violation of mandatory reliability standards. (See answer to question 12 for further discussion on reliability.)

REGULATION OF ELECTRICITY UTILITIES – POWER GENERATION

3 Authorization to construct and operate generation facilities

What authorizations are required to construct and operate generation facilities?

The siting and construction of electric generation, transmission and distribution facilities has historically been a state and local process, though EPAct 2005 altered this traditional arrangement by vesting limited transmission siting authority with FERC. In making siting decisions, state public utility commissions (PUCs) consider environmental, public health and economic factors. The PUCs exercise their authority in conjunction with state environmental agencies or local land use boards. A few states have a siting board or commission that provides a single forum where an electric utility or independent developer can obtain all necessary authorizations to construct electric facilities. Other states have not consolidated the siting process, and electric utilities or independent developers in those states are required to obtain the necessary permits separately from each of the relevant state and local agencies. The state and local permits required for the construction of electric generation facilities include air permits and water use or discharge permits from the state environmental agencies, and conditional land use permits, zoning variances, and building permits from local agencies.

Regulated utilities are required to obtain a certificate of public convenience and necessity from the relevant PUC in connection with the construction of generation, transmission and distribution facilities that will be subject to cost-base rate regulation. Except in limited circumstances where the relevant state commission refuses to act on an application for a year, or does not have jurisdiction to act (as in the case of certain federally designated National Transmission Corridors), no federal certificate of public convenience or necessity is either required or available from FERC for the siting and construction of electric generation, transmission or distribution facilities under part II of the FPA.

A FERC licence must be obtained under part I of the FPA for the construction of hydroelectric facilities on navigable waters. Construction affecting federal lands may also require authorization from agencies such as the Bureau of Land Management, the US Forest Service, or the National Park Service. The US Army Corps of Engineers reviews projects affecting wetlands or "navigable waters of the United States" (a term given an extremely broad interpretation). Nuclear facilities must be licensed by the US Nuclear Regulatory Commission (NRC). The Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE) within the Department of the Interior (DOI) are responsible for offshore renewable energy development. Reviews by the Pipeline and Hazardous Materials Safety Administration of the Department of Transportation (DOT) are also conducted. https://www.phmsa.dot.gov/registration/registration-overview

4 Interconnection policies

What are the policies with respect to interconnection of generation to the transmission grid?

FERC-jurisdictional transmission providers are required to provide interconnection service under the terms of an OATT. Generators have the right to request interconnection services separately from transmission services.

In response to complaints by generators that interconnection procedures were being used by some transmission providers in a discriminatory manner, FERC implemented rules to standardize agreements and procedures for generators and required FERC-jurisdictional transmission providers to interconnect generators to the grid in a non-discriminatory manner. Under the standard interconnection procedures, generators are required to advance the full cost of any interconnection facilities (from the generator to the point of interconnection) and network transmission facilities (beyond the point of interconnection) necessary to connect the generator with the transmission grid. The generator is reimbursed for the cost of any network transmission facilities through credits for future transmission service on the grid. ISOs and RTOs have the flexibility to propose changes to the standard interconnection agreement and procedures, as well as to the procedures for recovering interconnection costs. For example, ISOs and RTOs may seek authorization to allocate the costs of network upgrades to the generator requesting the upgrades (in exchange for granting capacity rights on the transmission system). FERC does not regulate local distribution facilities, but has authority to regulate the rates, terms and conditions of any wholesale sales transaction using such a facility. (See answer to question 11 for further discussion.)

To encourage development of new generation, FERC issued Order No. 807, easing the requirement for certain generator owners and operators to have an OATT on file with FERC for public utilities that are subject to those regulations solely because they own or operate Interconnection Customer Interconnection Facilities (ICIF)—that is, those that own generator tie lines. Previously, an ICIF owner or operator must have either filed an OATT or received a case-by-case waiver of the OATT requirement, and also was obliged to provide interconnection service to other generators that sought to interconnect to the grid using its ICIF.

To ease the regulatory burden on new generation developers, Order No. 807 grants a blanket waiver of all OATT and other open access requirements to any public utility that is subject to those requirements solely because it owns, controls, or operates an ICIF, including entities that do not sell electricity. In addition, the rule provides a safe harbor period for five years in which there is a rebuttable presumption that the ICIF owner has definitive plans to use its capacity, and therefore is not required to provide interconnection service to other generators seeking to interconnect generation in the same location during the safe harbor period.

Order No 2222 separately requires that RTOs issue rules that allow for the participation of distributed energy resources (DERs) on the grid. https://www.ferc.gov/media/ferc-order-no-2222-fact-sheet

5 Alternative energy sources

Does government policy or legislation encourage power generation based on alternative energy sources such as renewable energies or combined heat and power?

Yes. The federal government offers incentives for the development of alternative energy sources through two important tax credits: the production tax credit (PTC) and investment tax credit (ITC). Both of these credits have been extended several times past their original sunset dates. Most recently, in December 2020, Congress passed a one-year extension of credits for wind, and a two-year extension of credits for solar.

https://www.eia.gov/todayinenergy/detail.php?id=46576#:~:text=At%20the%20end%20of%20December,of%20the%20full%20credit%20amount

https://www.solarpowerworldonline.com/2020/12/solar-investment-tax-credit-extended-at-26-for-two-additional-years/

The wind energy PTC is currently in effect until the end of 2021.The PTC gives a tax credit of US$18 per MWh to wind. Solar facilities are eligible for up to a 26% Investment Tax Credit (ITC), which applies through 2022. The ITC is an alternative to the PTC, and it allows a project developer to elect a grant equal to up to 26 per cent of the facility's tax basis, so long as the facility is depreciable and amortizable. (Both the PTC for wind and the ITC for solar will gradually diminish in value for later investment in construction before they expire.)

The DOE is administering a loan guarantee program for renewable energy projects that can guarantee up to US$4.5 billion in loans. The DOE Office of Energy Efficiency and Renewable Energy (EERE) is the focal point for several additional alternative energy programs, including the bioenergy technologies program, the geothermal technologies program, the solar energy program, the hydrogen and fuel cell technologies program, and the wind energy and water power programs. The EERE provides a variety of forms of financial assistance for the research and development of renewable energy, including grants, laboratory subcontracts, and cooperative research and development agreements.

https://www.eia.gov/todayinenergy/detail.php?id=46576#:~:text=At%20the%20end%20of%20December,of%20the%20full%20credit%20amount.

https://www.solarpowerworldonline.com/2020/12/solar-investment-tax-credit-extended-at-26-for-two-additional-years/

As of February 2021, 30 states plus the District of Columbia and three territories have adopted renewable portfolio standards (RPS) that require electricity providers to obtain a minimum percentage of their power from renewable energy resources by a certain date, and seven other states and one territory have set voluntary goals for adopting renewable energy resources.

https://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx

Over half of US states include combined heat and power (CHP) or waste heat recovery as an eligible resource in their RPS programs.

https://www.aceee.org/toolkit/2020/02/combined-heat-and-power

Roughly half of the growth in renewables energy generation can be linked to state renewable energy requirements.

https://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx

https://www.aceee.org/toolkit/2020/02/combined-heat-and-power

Cogeneration and small power production purchase and sale requirements

Under the Public Utility Regulatory Policies Act of 1978 (PURPA), electric utilities were obligated to purchase or sell electric energy from or to a facility that is an existing qualifying cogeneration or small power production facility (QF). EPAct 2005 amended the mandatory purchase and sale requirements of PURPA. Now, if the QF is selling in a market that meets certain criteria established by FERC, that purchase obligation may be terminated. In 2006, FERC issued Order No. 688, which permits the termination of the requirement that an electric utility enter into new contracts to sell energy to or purchase energy from a QF as long as FERC makes the appropriate findings in connection with a utility's filing for relief.

Several utilities have successfully pursued relief under Order No. 688. These changes do not affect existing or pending contracts or obligations.

Order No. 872 grants flexibility to state regulatory authorities in establishing avoided cost rates for QFs sales inside and outside of the organized electric markets. The rule also gives states the ability to require that energy rates, but not capacity rates, vary during the term of a QF contract.

https://www.ferc.gov/news-events/news/ferc-affirms-clarifies-purpa-final-rule

Net Metering

To encourage the development of small-scale solar arrays, particularly residential arrays, many states require electric utilities to have net metering programs. Net metering programs require utilities to subtract energy that a customer generates from a small-scale solar array from that customer's monthly electric bill, and possibly even pay a customer who generates more energy than he or she uses.

At the beginning of 2016, some or all utilities in 41 states and the District of Columbia were required to have net metering programs. However, these programs have provoked controversy over whether net metered customers are being subsidized through cost-shifting rate structures. In 2015, Hawaii ended its retail-rate net metering program for new residential solar customers, citing concern for the stability of the state's grid. Nevada also proposed a reduction in net-metering rates in 2015, which would retroactively apply to existing solar customers. States such as Maine and Louisiana are also exploring alternative programs to net metering. Prices of solar panels have dropped rapidly and continue to do so: the installed price of residential solar declined from US$12.40 per watt in 1998 to US$2.81 in 2021.

https://news.energysage.com/how-much-does-the-average-solar-panel-installation-cost-in-the-u-s/

As of March 2016, distributed solar arrays totaled 9.1 GW of capacity nationwide, a 37% increase from the previous year (https://emp.lbl.gov/publications/tracking-sun-viii-installed-price).

https://eta-publications.lbl.gov/sites/default/files/tracking_the_sun_10_report.pdf

6 Climate change

What impact will government policy on climate change have on the types of resources that are used to meet electricity demand and on the cost and amount of power that is consumed?

Federal and state climate change policies promoting carbon-free energy sources are significantly impacting the types of resources used to meet US electricity demand, especially with regard to coal-fired power plants. Nonetheless, natural gas will likely continue to play a large role in electricity production for the foreseeable future. The US electric industry's reliance on natural gas to meet rising energy demands is driven primarily by cost considerations: natural gas is a cheap and plentiful domestic fuel source, and natural gas-fired power plants are a relatively quickly-built and inexpensive means by which utilities can meet the baseline and peak electricity demands of their customers.

Electricity production from coal-fired power plants has rapidly declined in the past decade, falling from almost 2,000 terawatt-hours (TWh) in 2007 to 966 TWh in 2019, a drop of 51.7 per cent.

https://www.eia.gov/todayinenergy/detail.php?id=43675

Meanwhile, generation from natural gas has quickly scaled up to meet demand, rising from 815 TWh in 2007 to 1,582 TWh in 2019.

https://www.eia.gov/energyexplained/electricity/electricity-in-the-us.php#:~:text=Fossil%20fuels%20are%20the%20largest,gas%20turbines%20to%20generate%20electricity.

This shift has been driven in large part by low natural gas prices, but federal and state emissions regulations have also played a role in the decline of coal-fired power plants. The federal Environmental Protection Agency (EPA) has placed stringent regulations on the emissions of coal-fired power plants through the Mercury and Air Toxics Standards (MATS) and the Cross-State Air Pollution Rule (CSAPR), both finalized in 2011. https://insideclimatenews.org/news/20012021/court-ruling-trump-rollback-coal-plants/.

Other EPA regulations finalized in 2015 require new coal-fired power plants to include partial carbon capture and sequestration (CCS) equipment. EPA's 2015 Clean Power Plan requires states to make plans to reduce the carbon dioxide emissions from their electric power plants to 32% below 2005 levels by 2030. Although these regulations have been delayed through litigation and turnover in presidential administrations, their prospect is nonetheless causing the retirement of many coal-fired power plants while discouraging the construction of any new ones. Furthermore, in 2016 the federal government announced a temporary moratorium on new leases of federal land for coal mining while it studies the program and considers raising royalty rates. In addition, regulations at the state and regional level, such as California's cap-and-trade system and the Regional Greenhouse Gas Initiative (RGGI) in the Northeast, effectively established prices on carbon emissions and limited their quantity. Other states have made plans to shut down coal-fired power plants within their borders, such as Oregon and Washington.

Although recent federal and state legislative initiatives have led to the development of significant numbers of large-scale renewable energy projects, the maximum deployment of these technologies is hampered by the inherent variability of resources such as wind, the need for additional backbone transmission capacity between regions, and the lack of storage capacity. Solar and wind energy have seen rapid growth but remain a smaller source of electric generation than coal or natural gas, growing from 35 TWh in 2007 to 720 TWh in 2019. https://www.eia.gov/energyexplained/electricity/electricity-in-the-us.php#:~:text=Fossil%20fuels%20are%20the%20largest,gas%20turbines%20to%20generate%20electricity.

Other proposed state and federal legislation (e.g., carbon taxes) and foreign policy initiatives (e.g., the US's renewed adherence to and compliance with the Paris Agreement) will impose additional costs on electricity generators using carbon-intensive fossil fuels. Federal and state initiatives to encourage carbon-free energy resources could incentivize other alternatives to coal – particularly new liquefied natural gas (LNG) and nuclear.

These legislative proposals may impose greater costs on the energy that is nonetheless consumed. State or federal governments could subsidize renewable energy and carbon mitigation initiatives through surcharges on electricity generation or consumption. Compliance costs incurred by utilities arising from state and regional cap-and-trade legislation, EPA regulation of greenhouse gasses as airborne pollutants under the Clean Air Act, and state renewable portfolio standards are passed on through electricity transactions. The calculation of costs and benefits of federal and state regulations will continue to be a controversial issue. For instance, the Supreme Court remanded EPA's MATS rule to the agency in 2015 because the court found that EPA should have considered the rule's costs before deciding to regulate.

Unexpectedly, consumption of electricity has been stagnant in the US over the past decade even as economic growth has returned. Total electric generation grew 29 per cent between 1985 and 1995, and 22 per cent between 1995 and 2005, but only 0.7 per cent between 2005 and 2015. In 2019, US energy consumption decreased by 0.9 percent from 2018, and US energy production exceeded US energy consumption for the first time since 1957. https://www.eia.gov/energyexplained/us-energy-

facts/#:~:text=After%20record%20high%20energy%20production,primary%20energy%20production%20in%202019.
Spending on energy efficiency has grown rapidly, which has likely slowed the growth in electricity consumption.

7 Government policy

Does government policy encourage development of new nuclear power plants? How?

Yes. The US DOE Loan Guarantee Program has promoted development of the nuclear power industry through total available loan guarantees of US $18.8 billion for the construction of new nuclear power plants in the US. These loan guarantees help developers of new nuclear plants in the US to obtain favorable financing terms, which is of critical importance when constructing plants with a projected price tag in the range of US$7 to US $10 billion per unit. Indeed, many companies considering construction of new plants have publicly stated that, absent a federal loan guarantee, they will not be able to finance and build their proposed projects. But many US new projects have been abandoned or cancelled due to a combination of low natural gas prices, high capital costs, long permitting, rate case, construction and amortization timetables, concern over nuclear energy following the Fukushima disaster, and slow growth of electricity consumption. To date, conditional loan guarantees of US$12 billion have been granted to the developers of two nuclear units in the state of Georgia, which are under construction and planned to be completed in 2021 and 2022.

https://www.energy.gov/articles/secretary-perry-announces-financial-close-additional-loan-guarantees-during-trip-vogtle

DOE's Loan Guarantee Program has earmarked an additional $2 billion for the construction of new uranium enrichment facilities in the US. Access to additional supplies of enriched uranium fuel will be critical to support US nuclear plants. The DOE granted a conditional loan guarantee of US$2 billion for the construction of a uranium enrichment plant in Idaho in 2010, but the project has been repeatedly delayed by financial considerations.

https://www.energy.gov/sites/prod/files/2020/01/f70/DOE-LPO_Advanced_Nuclear_Loan_Guarantee_Solicitation_16Jan20.pdf

The DOE also considered the loan guarantee application of the United States Enrichment Corporation, which was planning to construct a new uranium enrichment plant in Ohio, but it denied the application.

DOE is supporting the development of new nuclear technologies, such as small modular reactors and next-generation nuclear plants. In addition, EPAct 2005 further encouraged the construction of new nuclear plants by establishing a production tax credit. Under that plan, operators of the first 6,000 MW of capacity from new nuclear power plants that are placed in service before 2021 will receive a production tax credit of 1.8 cents per kilowatt-hour during the first eight years of the plant's operation. In 2018, the tax credit was extended for reactors entering service after 2020.

https://www.world-nuclear-news.org/NP-USA-extends-nuclear-tax-credit-deadline-1202187.html

https://www.congress.gov/bill/115th-congress/house-bill/1892/text

REGULATION OF ELECTRICITY UTILITIES – TRANSMISSION

8 Authorizations to construct and operate transmission networks

What authorizations are required to construct and operate transmission networks?

Construction

Construction of transmission facilities is primarily a state-regulated function, but federal authorities have jurisdiction over siting on federal lands, and multi-state projects may require the authorization of several states. Historically, this fragmented system for siting new power lines, in addition to other factors such as regulatory uncertainty on the state and federal levels associated with transmission cost recovery, has been a significant barrier to the development of new transmission in the US. The EPAct 2005 provides tools to DOE and the Federal Energy Regulatory Commission (FERC) to facilitate new construction and improvements to the existing transmission infrastructure.

EPAct 2005 directed the DOE to identify areas in which transmission capacity constraints or congestion adversely affects consumers (national interest electric transmission corridors) and gave FERC supplemental permitting authority to ensure timely construction of transmission facilities to remedy transmission congestion in those corridors. The DOE designated two such corridors in 2006, the Mid-Atlantic Area National Interest Electric Transmission Corridor and the Southwest Area National Interest Electric Transmission Corridor. However, in 2009 the Fourth Circuit Court of Appeals found that FERC lacks authority to permit transmission projects that states have actively rejected, although it found that FERC has the power to approve transmission projects that states have refused to act upon. In addition, the Ninth Circuit Court of Appeals struck down the corridor designations in 2011 on the basis that DOE had failed both to consult with the states (as required by EPAct 2005) and to analyze the environmental impacts of its actions under the National Environmental Policy Act. The DOE's most recent study was released in 2020, and did not designate any national interest electric transmission corridors.

https://www.energy.gov/sites/prod/files/2020/10/f79/2020%20Congestion%20Study%20FINAL%2022Sept2020.pdf

In comments on the study, electric utilities and state utility regulators expressed opposition to the designation of any corridors, while renewable energy developers suggested that they be allowed to submit congestion studies for specific areas to justify new transmission projects.

Operation

Operators of interstate transmission facilities, except for government entities and cooperative utilities, must file an OATT with FERC that provides for the sale of standardized transmission services at publicly posted rates. In order to qualify for OATT services, the purchaser must also provide OATT services over their transmission facilities (if they own any). FERC issued a series of orders, beginning with Order No. 890, that were intended to eliminate the broad discretion that transmission providers had in calculating available transfer capacity (ATC), increasing non-discriminatory access to the grid and ensuring that customers are treated fairly in seeking alternative power supplies. Since Order No. 890-A, transmission providers have implemented new service options for long-term firm point-to-point customers and adopted modifications to other services. Instead of denying a long-term request for point-to-point service because as little as one hour of service is unavailable in the course of a year, transmission providers are now required to consider their ability to offer a modified form of planning redispatch or a new conditional firm option to accommodate the request. This increases opportunities to utilize transmission efficiently by eliminating artificial barriers to use of the grid. This standardization reduces the potential for undue discrimination, increases transparency, and reduces confusion in the industry that resulted from the prior lack of consistency.

FERC regulations require the posting of ATC values associated with a particular path, but not the available flowgate capacity (AFC) values. Thus, transmission providers using AFC values must convert to ATC values in their postings to comply with FERC regulations. With respect to energy and generation imbalance charges, a transmission provider must post the availability of generator imbalance service and seek imbalance service from other sources in a manner that is reasonable in light of the transmission provider's operations and the needs of its imbalance customers. FERC also limited rollover rights to contracts with a minimum term of five years. In Order No. 890-B, FERC reiterated that a power purchase agreement must meet all of the requirements for designation as a network resource in order to be designated by the network customer or transmission provider's merchant functions.

Operators of transmission networks, other than government entities or utility cooperatives, are also required to participate in regional transmission planning by FERC's Order No. 1000. The plans for each region must take public policy requirements into account, such as state renewable portfolio standards. The plans also allocate the costs of identified projects to all entities that benefit economically from those projects. However, these cost allocations have been controversial, and in 2016 FERC denied PJM's cost allocation for a transmission project in Virginia and held that all costs of the project should be borne by the ratepayers of Dominion Resources.

The Artificial Island case is the lead case on cost allocation for transmission projects (using PJM's solutions-based DFAX methodology): https://insidelines.pjm.com/ferc-orders-rehearing-on-artificial-island/

https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/ferc-approves-cost-allocations-for-artificial-island-other-pjm-wires-projects-57633551

9 Eligibility to obtain transmission services

Who is eligible to obtain transmission services and what requirements must be met to obtain access?

See answers to questions 4 and 11.

10 Government incentives

Are there any government incentives to encourage expansion of the transmission grid?

Pursuant to EPAct 2005, FERC has established incentive-based rate treatments to encourage investment in and expansion of the US's aging transmission infrastructure. FERC Order No. 679 includes a number of key provisions to promote transmission investment, including:

- incentive rates of return on equity for new investment by public utilities (both traditional utilities and stand-alone transmission companies);

- a higher rate of return on equity for utilities that join or continue to be members of transmission organizations (for example, RTOs and ISOs); and
- various advantageous accounting methods, including:
  - full recovery of prudently incurred construction work, pre-operation costs and costs of abandoned facilities;
  - use of hypothetical capital structures;
  - accumulated deferred income taxes for stand-alone transmission companies;
  - adjustments to book value for stand-alone transmission company sales or purchases;
  - accelerated depreciation; and
  - deferred cost recovery for utilities with retail rate freezes.

In Order No. 679 and Order No. 679-A, FERC extended incentive rate treatments to all utilities joining ISOs or RTOs, irrespective of the date they join. However, this incentive does not apply to the existing transmission rate base that has already been built, as its purpose is to attract new investment in transmission.

The incentives in Order No. 679 and Order No. 679-A have spurred a much higher level of investment in transmission, as desired, but some observers have questioned whether the incentives are too lucrative. The Massachusetts Attorney General has successfully challenged the return on equity allowed for transmission projects in New England, and won millions of dollars in refunds from transmission companies. In 2012, FERC issued a statement updating its policies on transmission incentives, abandoning its previous "routine/non-routine" test to determine if incentives were merited. FERC also decided to require risk mitigation measures from applicants before allowing incentives for a project's risks.

11 Rates and terms for transmission services

Who determines the rates and terms for transmission services and what legal standard does that entity apply?

FERC has jurisdiction over unbundled transmission services (including transmission services provided over low-voltage facilities) provided by public utilities to wholesale customers or to retail customers with direct access. The states have jurisdiction over bundled retail service (i.e., a combined generation and delivery product sold to retail customers) where direct access is not available. Court decisions and the interconnectivity of the transmission grid in the continental US have led to an expansive view of what constitutes transmission service in interstate commerce in all areas of the US except Alaska, Hawaii and ERCOT (in Texas). The FPA, however, reserves to the states jurisdiction over the local distribution of electricity.

FERC jurisdictional utilities offering transmission services must do so under FERC-approved tariffs. Order No. 888 required jurisdictional electric utilities to submit pro forma OATTs that functionally unbundle transmission operations and services, and set forth rates for transmission and ancillary services. In 2007, FERC issued Order No. 890, which modified the pro forma OATT to better remedy undue discrimination by, among other things, providing greater transparency and consistency in the calculation of available transmission capacity, and requiring coordinated open transmission planning between regions.

Transmission providers are also required to maintain an open-access, same-time information system (OASIS) to publish information with respect to its transmission system, including services, rates, and available transmission capacity, as well as business rules, practices, and standards that relate to transmission services provided under the pro forma OATT.

Finally, the FPA empowers FERC to review rates and terms of transmission services to ensure that they are just and reasonable and not unduly discriminatory or preferential. Generally, tariffs and contracts for transmission services must be filed with FERC before service commences to allow an opportunity for Commission review, as well as public notice and comment. Because transmission services are a natural monopoly, Order No. 888 envisions that FERC will determine whether a particular tariff is just and reasonable via a traditional cost-of-service ratemaking inquiry that balances the ratepayers' and the utilities' financial interests to realize a rate within the zone of reasonableness. Tariffs can be challenged for being unjust, unreasonable, unlawful, or discriminatory.

By adding section 211A to the FPA, EPAct 2005 authorized FERC to require transmission providers not subject to its jurisdiction to provide open access to their transmission system at terms and conditions comparable to those the unregulated entity provides to itself. An unregulated entity may be exempt from section 211A if it sells less than 4 million MWh of electricity annually, or if it does not own or operate the transmission facilities needed to operate an interconnected system. However, many of these regulated entities already provide open access based on reciprocity agreements with transmission providers. FERC exercised its authority under section 211A for the first time in 2011, and ordered the Bonneville Power Administration to change its environmental redispatch practices that required wind generators to shut down without compensation during periods of high water volume on the Columbia River.

12 Entities responsible for assuring reliability

Which entities assure reliability of the transmission grid and what are their powers and responsibilities?

Since 1968, NERC has operated as the primary entity responsible for assuring the reliability of the grid. NERC develops reliability standards through an American National Standards Institute accredited process, and it monitors, assesses and enforces its members' compliance with such standards through a voluntary, self-regulatory process. EPAct 2005 added section 215 to the FPA, which provides for the creation of an Electric Reliability Organization (ERO) to establish and enforce reliability standards for the bulk power system in North America. FERC has certified NERC as the ERO. The ERO oversees an enforcement program that includes compliance audit and reliability readiness review programs, as well as a compliance-monitoring program.

FERC enforces the reliability regime by approving 83 mandatory reliability standards for the bulk power system proposed by NERC, approving delegation agreements between NERC and eight regional entities, and creating an internal Office of Electric Reliability. The mandatory reliability standards apply to users, owners, and operators of the bulk power system designated by NERC. Both monetary and non-monetary penalties may be imposed for violations of these standards. The current rules expand the scope of facilities that form part of the bulk electric system to those facilities operated at or above 100kV, and therefore covers entities that own or control such facilities with certain limited exceptions. In 2015, FERC approved in large part an application from Southern California Edison to exclude almost 2,500 circuit miles of 115kV lines from the bulk electric system.

In recent years NERC has taken the lead with respect to cybersecurity oversight of the grip, to include the CIPs listed here, which are current subject to enforcement. https://www.nerc.com/pa/stand/pages/CIPStandards.aspx

The replacement of coal-fired, nuclear, or other conventional generation resources with natural gas-fired and renewable energy resources may affect grid reliability. As a result, grid operators, such as RTO and ISOs, will likely need to develop approaches to effectively manage capacity during hours of peak demand, as well as manage overgeneration during off-peak hours. Technological developments, such as improvements to grid forecasting and the development of smart grid technology, are assisting grid operators in providing the flexibility needed to address the challenges presented by variable resources and decreased generation capacity from more traditional resources.

For example, the California ISO and PacifiCorp launched an energy imbalance market in 2014 to balance load and generation in 5-minute intervals. According to the California ISO, the energy imbalance market saved its participants over US$64 million by the end of March 2016. NV Energy has already joined the energy imbalance market, and other large utilities in the Northwest and Southwest are planning to join as well.

Storage on the grid has emerged as a significant topic with the rise in renewable intermittent generation. FERC Order No. 841 requires that RTOs allow energy storage resources fair and equal access to provide services in regional wholesale energy markets. https://www.renewableenergyworld.com/storage/ferc-upholds-order-opening-markets-to-energy-storage/#gref

REGULATION OF ELECTRICITY UTILITIES – DISTRIBUTION

13 Authorization to construct and operate distribution networks

What authorizations are required to construct and operate distribution networks?

Similar to generation, distribution is regulated primarily at the state level.

14 Access to the distribution grid

Who is eligible to obtain access to the distribution grid and what requirements must be met to obtain access?

Specific procedures for connection to the distribution grid vary from state to state. However, state laws generally provide that distributors cannot deny service that is in the public interest.

15 Rates and terms for distribution services

Who determines the rates or terms for distribution services and what legal standard does that entity apply?

FERC has jurisdiction over transmission of electric energy in interstate commerce by public utilities, regardless of the voltage level of the delivery facilities. Section 201 of the FPA reserves regulatory authority over all facilities used in the local distribution of electricity to the state utility commissions. In Order No. 888, FERC promulgated a seven-factor functional test for the case-by-case determination of the jurisdictional separation between FERC-jurisdictional interstate transmission service (including service over low-voltage distribution lines) and state-jurisdictional local distribution service. FERC generally defers to the states' application of this test. The functional test looks at the proximity of the facilities to retail customers; whether the facilities are radial in character; whether power flows into or out of the facilities; whether power entering the facilities is transported to another market; whether power is consumed in a defined area; whether the facilities include meters to measure power flow into the facilities; and the voltage of the power flowing through the facilities.

FERC determines the rates, terms, and conditions of transmission service in interstate commerce (including service over low-voltage facilities) under the FPA's "just and reasonable" standard based on cost-of-service principles. Where retail customers buy electricity from a wholesale provider, and the electricity is then delivered over distribution facilities by the load-serving entity, the state determines the rates, terms, and conditions of such distribution service. Because distribution services are considered a natural monopoly, state public utility commissions generally review tariffs for distribution services proposed by the utilities via a traditional cost-of-service ratemaking inquiry. State utility commissions generally approve the tariffs submitted by utilities if they are just and reasonable. The tariffs offered by utilities vary, even within a state.

REGULATION OF ELECTRICITY UTILITIES – SALES OF POWER

16 Approval to sell power

What authorizations are required for the sale of power and which authorities grant such approvals?

FERC has jurisdiction over sales of power at wholesale in interstate commerce, excluding any sales by federal or state governmental bodies and rural cooperatives that are indebted to the Rural Utilities Service (RUS) or cooperatives that sell less than 4 million MWh of electricity per year. Retail sales of electricity are regulated at the state level, with variation from state to state.

17 Power sales tariffs

Is there any tariff or other regulation regarding power sales?

Tariffs and contracts pursuant to which public utilities sell power generally must be filed with FERC (wholesale sales) or the applicable state PUC (retail sales) before service commences to allow the applicable regulatory entity an opportunity for review (and for public notice and comment). Under the FPA, FERC has jurisdiction over wholesale ratemaking and is charged with ensuring the rates, terms and conditions pursuant to which public utilities offer wholesale power sales are "just and reasonable."

FERC permits wholesale sales of power at market-based rates if the seller demonstrates a lack of market power by passing a series of horizontal and vertical market screens. FERC has commenced investigations to determine whether utilities should retain their authority to sell power at market-based rates after finding that certain utilities did not pass at least one of the screening tests. In response, several utilities voluntarily agreed to implement cost-based rate caps in the areas where FERC found a presumption of market power and revoked the market-based rate authority of a utility.

Sellers of wholesale power that have applied for and received FERC approval to sell power pursuant to a market-based rate tariff can thereafter enter into new power sales contracts and transactions without filing the contracts prior to commencing service. Instead, such sellers file quarterly reports of their power sales contracts and transactions under their market-based rate tariff. In the absence of a showing of a lack of market power, FERC regulates the rates for wholesale sales under cost-of-service rate-making principles, and each new contract must be filed with FERC before the commencement of service.

Unlike the situation with respect to transmission tariffs, FERC does not generally dictate specific non-price terms and conditions in wholesale power sales contracts, but does dictate specific non-price terms and conditions in the market-based rate tariff. The regulatory structure allows complaints to be filed challenging contracts or reported power sales transactions as being unjust, unreasonable, unlawful or discriminatory.

Retail sales are regulated at the state level, with significant variation from state to state. In the absence of a competitive retail market, retail rates are typically established based on cost of service.

18 Rates for wholesale of power

Who determines the rates for sales of wholesale power and what standard does that entity apply?

Section 201 of the FPA grants FERC exclusive regulatory authority over the wholesale sale of electricity in interstate commerce by jurisdictional entities. The state utility commissions retain regulatory authority over wholesale sales of electricity by purely intrastate wholesale sales (in practice, this class is limited to wholesale sales in Alaska, Hawaii and ERCOT), as well as wholesale sales by non-jurisdictional entities such as rural electric cooperatives, municipal utilities, and state- or federally created utilities.

The FPA grants FERC authority over all jurisdictional wholesale sales of electricity to ensure that wholesale rates are just, reasonable and not unduly discriminatory or preferential. Although traditionally FERC had employed a cost-of-service ratemaking inquiry when reviewing wholesale rates to realize this statutory mandate, FERC has also allowed the market to determine wholesale power rates where it has found that the seller and its affiliates lack or have mitigated vertical or horizontal market power, and have adequately restricted affiliate transactions with captive customers. Once FERC approves a jurisdictional entity's generic market tariff, the jurisdictional entity is free to negotiate with other parties in the marketplace over the specific rate charged for the wholesale sale without having to seek FERC approval of the agreement prior to commencing service.

19 Public service obligations

To what extent are electricity utilities that sell power subject to public service obligations?

At the retail level, electric utilities have traditionally operated under an obligation to serve. In exchange for what is generally an exclusive service territory and an opportunity to recover prudently incurred expenses through cost-based rates, utilities are obliged to provide service to all customers in that service territory, as well as to plan adequately for the future needs of customers. In states that adopt retail competition, certain electric utilities may still retain an obligation to provide service to customers who do not select a competitive supplier.

FERC has recognized that wholesale electricity sales are generally governed by private contract, rather than by regulatory order or an express obligation to serve.

REGULATORY AUTHORITIES

20 Policy setting

Which authorities determine regulatory policy with respect to the electricity sector?

A number of governmental agencies are involved in different aspects of the regulatory policies governing electricity. At the federal level, Congress ultimately determines the direction of national energy policy through legislation, but it delegates broad authority to implement legislative mandates to FERC, the DOE, and other administrative agencies. At the state level, electric utilities are regulated by PUCs.

21 Scope of authority

What is the scope of each regulator's authority?

FERC has authority to regulate the sale of wholesale power and transmission in interstate commerce and to grant and administer licenses for hydroelectric plants on navigable waters. Under the Public Utility Holding Company Act of 2005 (PUHCA 2005), FERC also has authority to grant exempt wholesale generator (EWG) status and foreign utility company (FUCO) status. As noted above, FERC exercises authority under PURPA with respect to qualifying small power production facilities and cogeneration facilities (QFs).

Order No. 872 granted flexibility to state regulatory authorities in establishing avoided cost rates for sales by qualifying facilities (QFs) inside and outside of the organized electric markets. The final rule also gave states the ability to require that energy rates, but not capacity rates, vary during the term of a QF contract. https://www.ferc.gov/news-events/news/ferc-affirms-clarifies-purpa-final-rule

FERC has jurisdiction over the disposition of assets subject to its jurisdiction, which includes mergers, asset divestitures, corporate reorganizations and other transactions in which there is a change in the control of jurisdictional assets. FERC also has oversight authority with respect to the issuance of securities (except if regulated by a state) and interlocks among the officers and directors of public utilities with the utility's financial institutions, or with the utility's suppliers of electrical equipment. Public utilities under FERC's jurisdiction are subject to various requirements with respect to accounting and record retention and are required to satisfy various reporting requirements.

Under PUHCA 2005, FERC has increased oversight over, and access to, the books and records of public utility holding companies and their subsidiaries and affiliates to the extent that such books and records pertain to FERC jurisdictional rates or charges. Any service company in a holding company system providing non-power goods and services to an affiliated FERC-jurisdictional public utility or natural gas company must file annual reports disclosing detailed information about their businesses. Public utility holding companies may seek exemptions and waivers from these regulatory requirements. An automatic exemption from all the requirements is available to companies that are jurisdictional holding companies solely with respect to ownership of EWGs, QFs or FUCOs. In addition, single-state holding companies are entitled to a waiver from some, but not all, of the requirements—but must seek the waiver from FERC.

The NRC licenses the construction and operation of nuclear power plants and other nuclear facilities to ensure the protection of public health and safety. The Atomic Energy Act (AEA) governs the use of nuclear materials by both military and civilian entities, requires that all nuclear facilities be licensed, and establishes compensation for, and limits damages arising from, nuclear accidents. The US adheres to the international nuclear liability instrument, the Convention on Supplementary Compensation. The NRC has developed detailed regulations and guidelines concerning all aspects of the operations of a nuclear power plant.

State PUCs regulate terms and rates for retail sales and delivery of electricity. PUCs are charged by their states with ensuring that the public has access to safe, reliable utility service at reasonable rates, and thus also have authority over at least some aspects of the organization and finances of public utilities. Many PUCs also have authority to make siting decisions for transmission lines and generation facilities. In other states, siting decisions are delegated to other agencies, either centralized or locally scattered.

Many local governments operate municipal utilities to provide electric service to their local communities. While most municipal utilities serve smaller communities, several large cities, for example, Los Angeles, Sacramento, San Antonio, Seattle, and Orlando, operate publicly owned electric utilities. Municipal utilities can be governed by city councils or boards of elected or appointed officials. In a few states, PUCs regulate municipal utilities.

The RUS promotes electrification of rural America by providing financing to local cooperatives. Electric cooperatives are governed by their member customers through an elected board of directors. Cooperative boards set rates and determine the types of services available and other policies. While it varies from state to state, PUCs often have the authority to regulate at least some aspects of cooperatives' activities. Rural cooperatives with loans outstanding from the RUS are also obliged to comply with various loan covenants and regulations that affect their operations. The Tennessee Valley Authority (TVA), formed in 1933 as a wholly-owned corporation of the US government, generates and transmits power in seven southeastern states. TVA is governed by a nine-member, part-time board, appointed by the President and confirmed by the Senate to serve staggered five-year terms.

The Bonneville Power Administration, Southeastern Power Administration, Southwestern Power Administration and Western Area Power Administrations are the four federal power marketing administrations (PMAs). The PMAs operate as agencies of the DOE in 33 states. In 2019, the PMAs marketed 4.5 per cent of the nation's total electricity generation.

https://www.publicpower.org/system/files/documents/2019-Public-Power-Statistical-Report.pdf

The PMAs do not own or operate generating facilities but market the power produced by federally owned hydro and nuclear facilities. Administrators of the PMAs have authority to set rates and must certify that such rates are "consistent with applicable law" and "the lowest possible rate to customers consistent with sound business principles."

22 Establishment of regulators

How is each regulator established and to what extent is it independent of the regulated business and other agencies?

FERC and NRC are each authorized to have five commissioners. The President nominates, and Congress confirms, commissioners for FERC and the NRC for staggered five-year terms. The President also appoints one commissioner to serve as chair of each commission. No more than three commissioners may belong to a single political party. Furthermore, FERC and NRC decisions are not subject to review by the President, Congress, the DOE or other agencies.

State PUCs vary in size, but generally have between three and seven commissioners. It is common to limit the number of commissioners who may be from a single political party. In most states, the governor appoints commissioners, with approval by the upper house of the state legislature, for staggered five or six-year terms. In some states, commissioners are elected. The governor typically designates one commissioner to serve as chair of the commission, although in some states the commissioners select the chair. State commissioners generally are subject to restrictions similar to those of their federal counterparts with respect to employment, investments and *ex parte* communications.

23 Appeal of decisions

Can decisions of the regulator be appealed, and to whom? What are the grounds and procedures for appeal?

Decisions by FERC can be challenged on both substantive and procedural grounds. Within 30 days of a final decision or order by FERC, a party to the proceeding (either the applicant or an intervenor) may file a request for rehearing with FERC.

Within 60 days of issuance of the decision on rehearing, an aggrieved party may request a review of the FERC decisions by a US Court of Appeals. The Court of Appeals generally will not consider any objections that were not raised in the request for rehearing to FERC. The D.C. Circuit recently overturned FERC's practice of tolling rehearing decisions.

US Supreme Court review is possible upon a showing of compelling cause (for example, a conflict between decisions of two or more circuits of the US Court of Appeals, or often where a rule issued by a federal agency is invalidated by a Court of Appeals). PUC decisions can be challenged through judicial appeals in state courts, or if the decision violates federal law, a cause of action could be brought in federal court (subject to various limitations).

ACQUISITION AND MERGER CONTROL – COMPETITION

24 Responsible bodies

Which bodies can approve or block mergers or changes in control or acquisition of utility assets?

FERC approval is required prior to the disposition of any facilities subject to its jurisdiction under the FPA of a value in excess of US$10 million, as well as direct or indirect mergers or consolidations of public utility facilities with those of any other person regardless of the value of the facilities. Facilities under FERC's jurisdiction under section 203 of the FPA include facilities used for transmission or sale of electric power in interstate commerce (including "paper facilities" such as contracts for wholesale power sales) as well as generation assets used for wholesale sales. FERC review is required if there is a change in "control" of jurisdictional facilities. In general, FERC will presume that a transfer of less than 10 per cent of a public utility's holdings is not a transfer of control.

Any holding company that owns an entity selling power at wholesale or transmitting electric energy must obtain FERC authorization to acquire securities valued in excess of US$10 million in any entity that sells at wholesale or transmits electric energy or to otherwise merge with any such entity with a value in excess of US$10 million. In addition, the transfer of specific assets or licenses may necessitate additional reviews. For example, the transfer of a nuclear generating facility requires NRC approval.

There is also a new notification requirement under Section 203 established by Congress.

https://www.federalregister.gov/documents/2020/06/02/2020-11869/implementation-of-amended-section-of-the-federal-power-act

FERC has established blanket authorizations for a variety of transactions. For example, transactions are automatically authorized in which a holding company that includes a transmitting utility or an electric utility seeks to acquire or take any security of a transmitting utility or company that owns, operates or controls only facilities used solely for transmission in intrastate commerce or sales of electric energy in intrastate commerce, or facilities used solely for local distribution or sales of electricity at retail. Transactions are also offered if they involve internal corporate reorganizations that do not present cross-subsidization issues or involve a traditional public utility with captive customers or that owns transmission assets.

Acquisitions by holding companies of non-voting securities do not require prior FERC authorization. Acquisitions by holding companies of voting securities do not require prior FERC authorization if, after the acquisition, the acquiring holding company will directly or indirectly own less than 10 per cent of the outstanding voting securities. Moreover, acquisitions by holding companies of foreign utility companies do not require FERC authorization except where the holding company or its affiliates has captive customers in the US, in which case the holding company must make certain representations that the transaction will not adversely affect such captive customers.

The Federal Trade Commission (FTC) and the Antitrust Division of the Department of Justice (DOJ) (collectively, the antitrust agencies) are the primary agencies with authority to enforce US antitrust and fair trade practice laws. The FTC and DOJ have the authority to review the antitrust implications of proposed mergers and certain acquisitions of assets or securities in the electricity sector under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR Act). In addition to FERC and the states, the antitrust agencies may challenge in court anti-competitive practices in the electricity sector.

Finally, individual state regulatory bodies often must approve an acquisition or divestiture of utility companies or assets in that state, pursuant to state law. The procedures and standards for that review vary from one state to another.

25 Review of transfers of control

What criteria and procedures apply with respect to the review of mergers, acquisitions and other transfers of control? How long does it typically take to obtain a decision approving or blocking the transaction?

In considering an application to merge, acquire or transfer control of assets under section 203 of the FPA, FERC must determine whether the proposed transaction is in the public interest. FERC's merger policy is evidenced by statements in Order No. 592, Revised Filing Requirements Under Part 33 of the Commission's Regulations, Order No. 642, FERC Stats. & Regs. ¶ 31,111 (2000), on reh'g, Order No. 642-A, 94 FERC ¶ 61,289 (2001).

FERC's determination requires an evaluation of the proposal's effect on competition, rates and regulation. FERC must also consider whether proposed acquisitions will result in cross-subsidization of any non-utility company in the same holding company system or in any pledge of utility assets for the benefit of any company in the same holding company system. FERC may approve an acquisition resulting in such cross-subsidization or pledge of utility assets only if FERC determines that such cross-subsidization or pledge will be consistent with the public interest.

With respect to assessing a proposed transaction's impact on competition under section 203 of the FPA, FERC's merger policy statement generally requires that applicants provide it with a competitive screen analysis (horizontal or vertical, as appropriate) showing the effect of the proposed disposition on relevant products in relevant geographical markets. The competitive screen analysis must:

- identify the relevant products (such as economic capacity and available economic capacity) and the geographical markets in which the competitive effects of the acquisition can be analyzed;
- determine the market shares of all participating firms and the degree of concentration in the market, both before and after the proposed acquisition; and
- identify the market characteristics that will influence the ability of the combining entities to adversely affect competition, such as barriers to entry into the relevant market by other firms.

Market power is measured in part using the Herfindahl-Hirschman Index (HHI) measure of market concentration. The current DOJ and FTC guidelines have higher HHI thresholds than FERC for determining market concentration, making it less likely for a particular market to be deemed "moderately concentrated" or "highly concentrated" based on HHI alone. FERC's horizontal electric utility merger analysis (See Appendix A to Order No. 592) does not track the DOJ and FTC guidelines, instead utilizing a more stringent standard to measure market concentration.

FERC currently evaluates both the magnitude of increases in market power and overall post-transaction concentrations of market power to identify those transactions that are likely to have an adverse impact on competition. Applicants, however, are allowed to identify in their analysis other factors that may help to negate the presumption, such as benefits that the proposed acquisition will bring.

FERC will provide expedited review of applications for approval of (i) transactions that are not contested, do not involve mergers and are consistent with FERC precedent, as well as uncontested transactions involving a disposition of only transmission facilities under the functional control of a FERC-approved RTO or ISO; (ii) transactions that do not require a competitive screen analysis; and (iii) internal corporate reorganizations that do not present cross-subsidization issues. For transactions that do not qualify for such expedited action, FERC is required to act within 180 days from the filing of an application, unless FERC determines there is good cause for requiring additional time, in which case the time for action may be extended up to 180 days. For example, FERC might extend the time frame for action if it finds that an evidentiary hearing is needed to determine whether the transaction is in the public interest.

The antitrust agencies may review the antitrust implications of mergers and certain acquisitions of assets or securities before those transactions are consummated under the HSR Act. The FTC promulgated a set of detailed rules which govern the pre-merger notification that must be filed in connection with such a transaction. A transaction subject to the HSR Act may not close prior to the expiration of the applicable waiting period, which is initially 30 days. If the antitrust agency decides to open a second-phase investigation, the waiting period will be extended until the 30th day following substantial compliance with a second request. If the reviewing antitrust agency determines that the transaction may harm competition in a relevant market, it may seek a preliminary injunction in federal court which would bar the consummation of the merger until the court (in a DOJ action) or the FTC (in an FTC action) has an opportunity to decide whether to seek a permanent injunction following a full trial. Such a preliminary injunction does not issue automatically. In deciding whether to preliminarily enjoin a merger, the courts grant heavy consideration to whether the antitrust agency will eventually be able to prove its case at trial.

If the reviewing antitrust agency determines that the transaction may harm competition in a relevant market, such issues must be resolved before the transaction can proceed. In the electric sector, FERC (not the antitrust agencies) generally takes the lead in addressing any anti-competitive issues presented by a proposed transaction. Under the HSR Act, however, merging entities in such a situation often enter into a consent order with an antitrust agency under which the acquiring company agrees to divest a portion of its existing assets or of the assets it will be acquiring.

Finally, individual state regulatory bodies often must approve an acquisition or divestiture of utility companies or assets in that state, pursuant to state law. The procedures and standards for that review vary from one state to another.

26 Prevention and prosecution of anti-competitive practices

Which authorities have the power to prevent or prosecute anticompetitive or manipulative practices?

The federal agencies that are primarily concerned with anticompetitive practices in the wholesale electricity sector are FTC, DOJ, FERC and the Commodity Futures Trading Commission (CFTC). State utility commissions and attorneys general generally, but not exclusively, focus on such practices in the retail electric sector.

27 Determination of anti-competitive conduct

What substantive standards are applied to determine whether conduct is anti-competitive or manipulative?

FERC enforces compliance with tariffs or contracts in an effort to assure service is "non-discriminatory" and charges are "just and reasonable." EPAct 2005 amended the FPA to prohibit buyers or sellers of interstate wholesale electric energy or transmission services from knowingly providing a federal agency with false information or from using any manipulative or deceptive device or contrivance in violation of FERC regulations. Further, a seller of electric products and services applying for market-based rate authority must show it does not possess unmitigated market power in the affected markets.

The CFTC has authority to ensure futures and options markets operate fairly and orderly under the Commodity Exchange Act. This authority overlaps FERC's authority to the extent conduct involves trading and hedging activities of electricity and similar commodities. Under the Dodd–Frank Wall Street Reform and Consumer Protection Act, the CFTC has expended authority to direct market reforms.

As well as developing regulations, the CFTC has issued a rule exempting RTO and ISO system operators from CFTC regulation. The exemption covers certain financial transmission rights, energy transactions, and forward capacity transactions sold pursuant to an RTO or ISO governing tariff if the transaction is related to the allocation of physical electric energy and carried out by an "appropriate person," that is, those individuals or entities meeting certain sophistication or financial thresholds. However, the exemption does not apply to the CFTC's antifraud or anti-manipulation regulation.

The FTC has concurrent authority, pursuant to the FTC Act, to enjoin "unfair methods of competition." The FTC's authority extends to acquisitions that tend to substantially lessen competition, as well as to price discrimination and other anti-competitive actions. The FTC also has authority to directly protect consumers from any "unfair or deceptive" practice, defined as an act "that causes or is likely to cause substantial injury to consumers that is not reasonably avoidable by consumers themselves and not outweighed by countervailing benefits to consumers and to competition."

The FTC and the DOJ have concurrent power to prosecute violations of the other federal antitrust statutes. States and private parties may also bring actions under federal and state antitrust laws. This was reaffirmed by the US Supreme Court in 2015, which ruled that the federal Natural Gas Act does not pre-empt state antitrust laws. So a private party may bring state antitrust claims for alleged pipeline price manipulation.

Section 1 of the federal Sherman Act prohibits "agreements, conspiracies or trusts in restraint of trade." Under the Sherman Act, some agreements (such as agreements of horizontal price-fixing or territorial division) are determined to be per se illegal because the conduct of the agreement is overwhelmingly considered to be harmful. Other agreements that may potentially be harmful are analyzed under the rule of reason, requiring the plaintiff to prove that the agreement caused economic harm. Section 2 of the Sherman Act prohibits monopolies, specifically targeting anti-competitive conduct that creates or maintains market domination. The Clayton Act bars certain types of price discrimination and tying arrangements when they lessen competition.

28 Preclusion and remedy of anti-competitive practices

What authority does the regulator (or regulators) have to preclude or remedy anti-competitive or manipulative practices?

If a proposed tariff or contract is found by FERC to be unjust and unreasonable, FERC will order mitigating revisions. FERC may require the sellers to refund the difference between the rates collected and the rates FERC determines are just and reasonable, beginning with the date the investigation was initiated. In order for a seller to be eligible to sell wholesale at market-based rates (instead of at cost-based rates), it must demonstrate to FERC that it and its affiliates lack (or have mitigated) market power. FERC can refuse to grant market-based rate (MBR) authority to an applicant that fails to show it does not possess market power. At any point, FERC has the authority to revoke market-based rate authority upon a determination that the seller possesses market power. In addition, FERC maintains the ability to revoke prior grants of MBR authority if the company's behavior involves fraud, deception or misrepresentation.

Once initially granted MBR authority, sellers are required to take additional measures in order to maintain the market-based rate authority. For example, sellers of more than 500MW of generation in any region of the country must file updates every three years in order to demonstrate its continued lack of market power. Also, such an electrical provider must notify FERC within 30 days of any significant change that might affect its qualification for market-based rates. Further, FERC has enacted market behavior rules in order to govern sellers' conduct in the wholesale market. These rules address unit operations, communications, price reporting and record retention. On an ongoing basis, FERC has authority under section 206 of the FPA to regulate markets and protect them against anticompetitive activity. Section 206 grants FERC authority to initiate an investigation, upon its own motion or third-party complaint, regarding whether any rate charged by a utility for any transmission or sale is "unjust, unreasonable, unduly discriminatory or preferential."

EPAct 2005 amended the FPA to allow for increases in the maximum penalty amounts for violations of the FPA. FERC is now able to assess civil penalties and fines of up to US$1 million or imprisonment for not more than five years, or both, for willful and knowing violations, through acts or omissions, of any section of the FPA. Also, EPAct 2005 provides for civil penalties of up to US$1 million per violation per day to be assessed after notice and the opportunity for a public hearing. While FERC has used its penalty authority sparingly in the past, there are indications that, pursuant to its expanded authority, FERC will act more forcefully to demonstrate its authority with more enforcement actions. In the fiscal year 2020, FERC Office of Enforcement recovered through negotiated settlements approximately US$21.3 million in civil penalties and disgorgement of nearly US$667,000 in unjust profits (https://www.ferc.gov/enforcement-legal/enforcement/civil-penalties/all-civil-penalty-actions-2020).

The FTC Act authorizes the FTC to issue "cease and desist" orders requiring electric utilities to refrain from prohibited unfair trade practices and may assess civil penalties for violations. Violations of sections 1 and 2 of the Sherman Act may result in fines up to US$100 million for corporations, US$1 million for individuals, and up to 10 years of imprisonment. In 2021, the FTC recently increased the maximum civil penalty amount to US$43,792 per violation per day under both Section 5 of the FTC Act and Section 7 of the Clayton Act. https://www.ferc.gov/enforcement-legal/enforcement/civil-penalties/all-civil-penalty-actions-2020

In addition, under the antitrust acts, private parties are able to bring enforcement actions to address unfair trade practices in the electric sector, including tying arrangements, price squeezes, and denial of access to essential facilities.

INTERNATIONAL

29 Acquisitions by foreign companies

Are there special requirements or limitations on acquisitions of interests by foreign companies?

Several current or former US utilities are or have been owned by foreign parties, including Central Hudson Gas and Electric and UNS Energy (both indirectly owned by Fortis, Inc, a Canadian company), National Grid USA (owned by UK's National Grid), New York State Electric and Gas (owned by the Spanish utility, Iberdrola), and LG&E (owned by Germany's E.ON but sold to a US company in 2010). However, new investors should be mindful of current US regulatory and political attitudes toward foreign investment in the energy sector.

The Exon-Florio amendment to the Defense Production Act authorizes the President of the US to block a transaction pursuant to which foreign persons would gain control of a US business, if such transaction poses a threat to national security. The Foreign Investment and National Security Act of 2007 (FINSA) confirms the broad range of energy and infrastructure transactions that may be covered, and intensifies the screening for certain transactions.

Exon-Florio is administered by the Committee on Foreign Investment in the US (CFIUS), an inter-agency committee chaired by the secretary of the Treasury and including the attorney general and secretaries of homeland security, commerce, defence, state and energy. CFIUS is responsible for reviewing proposed foreign investment transactions and making recommendations to the President.

FINSA confirms that Exon-Florio applies to acquisitions of "critical infrastructure." This term has been defined as systems or assets so vital to the US that the incapacity or destruction of it would have a debilitating impact on national security. While the definition has been applied to ports and oil companies, it is now clear that electricity generating, transmission and distribution facilities would be considered critical infrastructure.

FINSA formalizes many CFIUS practices, including explicitly encouraging parties to notify and engage with CFIUS regarding a transaction in order to seek CFIUS clearance. FINSA provides for a 30 to 45-day CFIUS review of covered transactions; reviews are mandatory for covered transactions involving foreign government-controlled entity.

For nuclear-generating facilities, the Atomic Energy Act (AEA) generally bars the issuance of a reactor license to a non-US person. For example, the NRC Atomic Safety and Licensing Board denied a license for a proposed nuclear project in Maryland because the applicant was 100 per cent owned by a foreign entity. Situations where a foreign company would be able to hold a license include (i) when the company owns up to 50 per cent of an entity whose officers and employees responsible for special nuclear materials are US citizens, or (ii) when the foreign company owns a US subsidiary that will hold the license, the foreign company's stock is "largely" owned by US citizens, and the subsidiary's officers and employees responsible for special nuclear materials are US citizens. The NRC has indicated it may relax this requirement in the future, as in 2015 it ordered commission staff to develop a regulatory guide that will use a "graded approach" to assess and mitigate potential foreign ownership, control, or domination of US nuclear facilities.

30 Cross-border electricity supply

What rules apply to cross-border electricity supply, especially interconnection issues?

No electric transmission lines crossing the US international border may be constructed or operated without a presidential permit. The secretary of energy (through the DOE's Office of Electricity Delivery and Energy Reliability) will issue such a permit upon determining that the project is in the public interest. The two primary criteria used to determine if a proposed project is consistent with the public interest are (1) the impact the proposed project would have on the operating reliability of the US electric power supply, and (2) the environmental consequences of the proposed project. The DOE must also obtain concurrence from the Secretary of State and the Secretary of Defense before issuing a permit.

The FPA allows exports of electric energy unless the proposed export would impair the sufficiency of electric power supply within the US or would impede or tend to impede the coordinated use of the US power supply network. Based on these guidelines from the FPA, DOE (again through the Office of Electricity Delivery and Energy Reliability) grants authorization to export electric energy if it determines that sufficient generating resources exist such that the exporter could sustain the export while still maintaining adequate generating resources to meet all firm supply obligations, and the export would not cause operating parameters on regional transmission systems to fall outside of established industry criteria. The DOE must also comply with the National Environmental Policy Act before granting authorization to export electric energy. No federal permit is required to import electricity into the US, and no federal permit is required to sell imported electricity, if the sale at issue takes place outside of interstate commerce.

Federal regulation of a sale for resale in interstate commerce of imported or domestic electricity will apply if title to the electricity changes hands at a point within the US. In this case, the seller must apply to FERC for approval of the rates, terms and conditions of the sale. There are two exceptions. First, in the event the sale for resale in interstate commerce of imported or domestic electricity is conducted by a US government-owned, US state-owned, or US municipally owned utility, or is conducted by a US Department of Agriculture Rural Utilities Service-financed rural electric cooperative, there will be no FERC regulation of the sale. Second, there will be no FERC regulation of retail sales of imported or domestic electricity. The state PUC may regulate the retail sales of electricity within its border.

TRANSACTIONS BETWEEN AFFILIATES

31 Restrictions

What restrictions exist on transactions between electricity utilities and their affiliates?

FERC has issued a series of orders, including Order No. 717, Order No. 787 and Order No. 807, which establish the current standards of conduct governing relations between transmission providers for both electricity and natural gas on the one hand and their affiliates on the other hand. The rule concentrates on three principles to avoid affiliate abuse. The main elements are the independent functioning rule, the no-conduit rule, and the transparency rule.

Independent functioning rule

FERC eliminated completely the concept of energy affiliates as well as the corporate separation approach to separating grid operators from marketing affiliates, two aspects of the old Order No. 2004 rules that had proven difficult to understand and enforce. Instead, Order No. 717 is based on the employee functional approach that was first utilized in industry restructuring orders from the 1980s and 1990s. This approach focuses on an employee's actual function on the job rather than the employee's position in the organization chart. Thus, whereas under former rules any employee of a marketing or energy affiliate was prohibited from interacting with transmission function employees, Order No. 717 limits the category of employees who must function independently from transmission operators to those who are actively and personally engaged on a day-to-day basis in marketing functions. By narrowing the focus in this manner, the rule provided clarity to supervisors, managers, and executives, and allowed the free flow of the type of information needed for long-term planning.

No-conduit rule

The no-conduit rule prohibits a transmission provider from using anyone as a conduit for the disclosure of non-public transmission function information to its marketing function employees. This rule covers both information and employees not falling within the scope of the independent functioning rule. For example, although there is no general requirement that lawyers employed by transmission providers need to function independently of the company's marketing function employees, lawyers must nevertheless avoid serving as a conduit for passing nonpublic transmission information to marketing function employees.

Transparency rule

The FERC orders are also designed to promote transparency through the collection, reporting, and public posting requirements of information that may alert interested persons and FERC to potential acts of undue preference.

Reliability exception

Reflecting the importance of reliability, Order No. 717 makes an exception to the independent functioning rule and the no-conduit rule for the exchange of information "pertaining to compliance with reliability standards approved by the Commission" and information "necessary to maintain or restore operation of the transmission system or generating units, or that may affect the dispatch of generating units."

32 Enforcement and sanctions

Who enforces the restrictions on utilities dealing with affiliates and what are the sanctions for non-compliance?

FERC has authority to impose penalties in the amount of US$1 million per day per violation under sections 316 and 316A of the FPA or to use its rate authority to remedy affiliate abuse, as discussed more fully in the answers to questions 27 and 28.

Mechanisms for enforcement and remedies for violations of the affiliate rules of various states vary widely.

* *Thanks to my Pillsbury colleagues—Michael Hindus for drafting the 2011 version of this survey, and Katherine Vorhis, and Chelsea Gunter for their participation in researching subsequent updates.*