Chambers

GLOBAL PRACTICE GUIDES

Definitive global law guides offering comparative analysis from top ranked lawyers

Alternative Energy & Power

USA

Troutman Sanders LLP

2019

USA

LAW AND PRACTICE: p.3

Contributed by Troutman Sanders LLP

The 'Law & Practice' sections provide easily accessible information on navigating the legal system when conducting business in the jurisdiction. Leading lawyers explain local law and practice at key transactional stages and for crucial aspects of doing business.

Law and Practice

Contributed by Troutman Sanders LLP

CONTENTS

Troutman Sanders LLP energy practice groups have counselled utilities and other energy clients about changing regulatory challenges since the 1920s. The team, with more than 100 attorneys focused on the energy industry, handles matters across the energy-related sector including renewable energy, nuclear, oil and natural gas, energy construction, electricity and energy storage. With a diverse practice mix, workforce and footprint that includes 12 offices across the United States, Troutman Sanders has cultivated its reputation for a higher commitment to client care for over 120 years. Ideally positioned to help clients across sectors realise their business goals, the firm's 650 attorneys transact for growth, resolve mission-threatening disputes and navigate complex legal and regulatory challenges. Key areas of expertise in the alternative energy & power sector include: energy policy and legislation, state energy regulation, capital projects and infrastructure, renewable energy, electricity, energy storage and nuclear power.

1. General Structure and Ownership of the Power Industry

1.1 Principal Law Governing the Ownership and Structure of the Power Industry

In the United States of America ("U.S.") the generation, transmission, distribution and supply segments of the electric industry are owned and/or controlled by: (i) private interests and investors; (ii) cooperatives; and (iii) government and/or public entities/authorities.

Investor ownership in the U.S. power sector may be either through securities (publicly traded on major exchanges) *[See https://www.statista.com/statistics/237773/the-largest-electric-utilities-in-the-us-based-on-market-value/]*, or through privately-held equity *[See, e.g., https://www.utilitydive.com/news/with-aep-deal-private-equity-continues-gobbling-up-utility-plants/426486/]*. So-called "investor-owned utilities" ("IOUs") are vertically integrated companies, often providing generation, transmission, distribution and supply services on an integrated basis. Many U.S. IOUs' stocks are publicly traded on the NYSE, usually via holding company securities. Such public utility operating companies are also owned by private equity firms, some of which are not U.S.-based (e.g., Tucson Electric Power Company is owned by Fortis, Inc., a Canadian-based private equity firm). Private investors are also extremely active owners of single-sector assets. Generation-only entities (known as independent power producers ("IPPs")) may also be publicly traded or owned through private equity investors (which include, e.g., Blackstone, ArcLight Capital Partners, Energy Capital Partners, and Riverstone Holdings). Many generation-only entities also own renewable energy resources (i.e., solar, wind, etc.) known as qualifying facilities ("QFs"). Some large transmission-only entities are privately-held (e.g., ITC Holdings, ATC LLC). Wholesale and retail marketers and traders also play important roles in the market.

Cooperatives typically serve rural areas, and the U.S. hosts approximately 900 of them. They serve 12% of the nation's electric consumers and own 42% of the distribution assets (by line mileage). Cooperatives are considered nonprofit corporations under the U.S. Internal Revenue Code (Section 501(c)(12)), and are granted Federal tax-exempt status as long as 85% or more of their annual income is derived from co-op customer-owner/members. This effectively means that co-ops are wholesale buyers and retail sellers, with little participation as sellers in the bulk power market. Co-ops generally take two forms: (1) distributions co-ops (which distribute electricity procured at wholesale to their retail customers/co-op members); or (2) generation and transmission ("G&T") co-ops (which are owned, in turn, by distribution co-op members who pool resources to fund such capital projects). G&T cooperatives are dedicated to serve their distribution co-op members. Cooperatives are eligible for government-backed loans from the U.S. federal government, in particular the Rural Utilities Service (which is an arm of the U.S. Department of Agriculture).

Government and/or publicly-owned entities/authorities are also active in U.S. power markets. Generally referred to as "public power" these entities include: (1) municipally-owned distribution utilities ("munis"); (2) irrigation districts or public utility districts ("PUDs"); and (3) the federal power marketing administrations ("PMAs") and the Tennessee Valley Authority ("TVA"). Munis are mostly distribution-only entities that buy their electricity from other sources at wholesale and serve their own customers at retail. Municipals often join together in "joint action agencies" (e.g., AMP-Ohio and Michigan Municipal Power Agency) or may act on their own as large vertically-integrated retailers (e.g., Los Angeles Department of Water and Power and Seattle City Light). Irrigation districts and PUDs are creatures of state statute. They are created by state governments to develop large irrigation projects and purchase wholesale electricity for irrigation pumping power (in the case of irrigation districts), or specifically to provide public utility services to a particular area (in the case of PUDs). PUDs are located mostly in the Pacific Northwestern U.S. The PMAs include the Bonneville Power Administration ("BPA"), the Western Area Power Administration (WAPA), the Southeastern Power Administration (SEPA), and the Southwestern Power Administration (SWPA). These entities market electricity from hydroelectric dams owned and operated by the U.S. government. These federal dams are located on the large river systems in the Western U.S. (i.e., the Columbia River and the Colorado River) and include significant projects such as the Hoover Dam and the Grand Coulee Dam. The PMAs utilize government-backed debt from the U.S. Treasury (i.e., at lower interest rates than private bonds). Unlike the PMAs, TVA, is a government-owned corporation. It also operates and markets electricity from federal dams, however in the Southeastern U.S.

1.2 Principal State-Owned or Investor-Owned Entities

- A list of investor-owned utilities can be found here: http://www.eei.org/about/members/uselectriccompanies/Pages/usmembercolinks.aspx
- Large IPPs include, e.g., Dynegy, Calpine, and NRG. See also https://epsa.org/.
  A list of public power entities can be found here: https://www.publicpower.org/

- A list of cooperatives can be found here: https://www.electric.coop/

1.3 Foreign Investment Review Process

Traditionally, the U.S. federal government maintains an open policy concerning foreign direct investment ("FDI"). In recent decades, the FDI regime focuses on increased scrutiny with the establishment of the interagency Committee on Foreign Investment in the United States ("CFIUS") in 1975 by Executive Order, whose members include the U.S. Department of Energy. In 2007, Congress passed the Foreign Investment National Security Act of 2007 ("FINSA") *[See, Foreign Investment and National Security Act of 2007, Pub. L. No. 110-49, § 12, 121 Stat. 246 (2007).]*, which instructed CFIUS to apply heightened scrutiny to any FDI resulting in foreign control over U.S. 'critical infrastructure' or control of a U.S. business by a foreign government. Each transaction is reviewed on a case-by-case basis based on the relevant facts and circumstances. The U.S. President has authority under section 721 of the Defense Production Act of 1950 *[See, 50 U.S.C. § 2170 (2018).]* to review acquisitions or investments in U.S. businesses by foreign persons. The authority to investigate applicable investments has been delegated to CFIUS. Upon investigation into relevant investments by CFIUS, the U.S. President may suspend or prohibit certain transactions. While CFIUS regulations do not specify the sectors for which investments constitute 'critical infrastructure,' in practice, this includes the energy sector.

1.4 Principal Law Governing the Sale of Power Industry Assets

The Federal Energy Regulatory Commission ("FERC") has authority to review and approve mergers and acquisitions, consistent with its authority under the Federal Power Act ("FPA") *[See, 16 U.S.C. §§ 791-828c (2018).]*. Under section 203 of the FPA, public utilities subject to FERC's jurisdiction must seek FERC's prior approval before engaging in certain transactions, including those involving the sale and purchase of jurisdictional utility assets. Specifically, section 203(a)(1) requires that an entity must generally obtain FERC prior approval to: (A) sell, lease, or otherwise dispose of the whole of its facilities subject to the jurisdiction of the Commission, or any part thereof of a value in excess of USD10,000,000; (B) merge or consolidate, directly or indirectly, such facilities, or any part thereof, of a value in excess of USD10,000,000, with those of any other person, by any means whatsoever; (C) purchase, acquire, or take any security with a value in excess of USD10,000,000 of any other public utility; or (D) purchase, lease, or otherwise acquire an existing generation facility— (i) that has a value in excess of USD10,000,000; and (ii) that is used for interstate wholesale sales and over which the Commission has jurisdiction for rate-making purposes. In addition, such transactions may also be subject to state laws and prior approval requirements. Such pre-approvals are administered by state public service commissions or public utility commissions.

1.5 Central Planning Authority

There is no U.S. central federal authority that administers the electric supply and the development of transmission facilities to ensure the reliability of the electric system and the adequacy of supply to satisfy the demand for electricity. FERC has jurisdiction over the "transmission of electric energy in interstate commerce," and over the "sale of electric energy at wholesale in interstate commerce," and over "all facilities for such transmission or sale of electric energy." *[See, 16 USC 824(b) (2018).]*. This jurisdiction excludes only the states of Hawaii, Alaska and parts of Texas. Although FERC has authority to regulate and oversee a vast array of technical industry reliability requirements under EPAct 2005, FERC does not get involved in making resource decisions and selections on behalf of customers or citizens. In contrast, states regulate retail sales of electricity, and the individual states' roles in overseeing and managing resource adequacy varies widely among the fifty states. Certain states require vertically-integrated utilities to submit so-called "integrated resource plans," which require utilities to demonstrate how they will meet the needs of customers over a planning horizon, and with what resource mix. Certain states (for example, California) take a proactive approach to assuring a particular resource adequacy mix. These states have fostered renewable energy and demand side programs as part of the requirements placed on utilities to reliably meet in-state load. In addition, entities known as "Regional Transmission Organizations" ("RTOs") and "Independent System Operators" ("ISOs") operate the electric transmission system on a regional basis to meet regional needs and demands in many parts of the U.S. These entities also function as the overseers of regional transmission planning and act as central, regional market-makers in the generation business. For example, several RTOs and ISOs establish capacity auctions to ensure that regional demands and resource adequacy needs are met through advance market mechanisms.

1.6 Material Changes in Law or Regulation

There are several new regulations promulgated by either FERC or other governmental agencies that have impacted the power industry. First, FERC issued two final rules in February 2018, one on the participation of electric storage in regional markets (Order No. 841) and the other rule on primary frequency response (Order No. 842)) *[See, Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, Final Rule, Order No. 841, 162 FERC ¶ 61,127 (2018); Essential Reliability Service and the Evolving Bulk-Power System—Primary Frequency Response, Final Rule, Order No. 842, 162 FERC ¶ 61,128 (2018).]*. Both of these rules respond to the change in the U.S.' energy supply resource mix and the emergence of energy storage technologies. Order No. 841, in general, requires regional market operators to implement a set of changes to their tariffs, business practices and operations to accommodate the participation of electric storage resources in regional markets (heretofore designed mainly for conventional generation resource participation). Order No. 842 requires newly-interconnecting generators to provide Primary Frequency Response (a type of ancillary service), the availability of which had been in decline as older conventional resources continued to retire and newer units were added without the ability to provide Primary Frequency Response.

Second, in March 2018, the federal government implemented the Tax Cuts and Jobs Act of 2017. *[See, Tax Cuts and Jobs Act of 2017, H.R. 1, 115th Congress, § 11000 (2017).]*. The Tax Cuts and Jobs Act of 2017, among other things, lowered the federal corporate income tax rate which impacted the electricity companies whose current transmission rates includes fixed rates that were based on the outdated tax rate. Companies filing to update their cost-based reactive power rates would also be affected by this tax law change.

Third, in April 2018, FERC issued a new reform that revised its standard large generator interconnection procedures and agreement to enhance the interconnection process for agreements for generators of more than 20 megawatts. *[See, Reform of Generator Interconnection Procedures and Agreements, 163 FERC ¶ 61,043 (2018).]*. The purpose of this reform is to improve the efficiency of processing interconnection requests, remove barriers to resource development and ensure grid reliability.

Fourth, FERC instituted a new order in April 2018, Order No. 844 *[See, Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators, 163 FERC ¶ 61,041 (2018).]*, requiring each RTO and ISO to establish in its tariff certain requirements to report information regarding uplift cost allocation practices. FERC instituted these requirements in order to provide transparency of the price formation process. While FERC had originally proposed to require a more granular cost allocation to costs that were "socialised" across an RTO footprint, in Order No. 844, FERC merely required a series of reports to be periodically filed discussing the scope of the uplifted costs.

1.7 Announcements Regarding New Policies

In September 2017, the Secretary of the U.S. Department of Energy ("DOE") proposed that FERC issue a final rule to ensure just and reasonable rates for "fuel-secure" generation units (e.g., coal and nuclear units). The DOE initiative quickly became known as the "resiliency rule." The DOE directed FERC to issue a final rule that required its organised markets to develop and implement market rules that appropriately priced generation resources that are important to maintain the reliability and resiliency of the U.S. power system. The resiliency rule would have essentially provided for a cost-based rate for nuclear and possibly coal-fired generators. The rule was ultimately not adopted and the rulemaking was terminated by FERC. FERC is still gathering information from regional market operators and continues to examine the issue of grid resiliency.

In December 2016, FERC instituted a Notice of Proposed Rulemaking, "Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators." In the proposed rulemaking, FERC proposed to address the pricing of energy from fast-start resources (i.e., a resource that is able to start up within ten minutes or less, that has a minimum run time of one hour or less, and that submitted an economic energy offer to the market). While FERC withdrew the notice of proposed rulemaking in 2017, FERC initiated investigations into the pricing of fast-start resources in three regional power markets upon finding that their current market practices may be unjust and unreasonable shortly thereafter. FERC is in the process of investigating, under the FPA, whether tariff revisions are necessary for the New York Independent System Operator ("NYISO"), PJM Interconnection, L.L.C. ("PJM") and Southwest Power Pool ("SPP"). Depending upon FERC's findings, there may be material, region-wide changes.

More recently, in April 2018, FERC issued a Notice of Inquiry to examine whether to change its 1999 Policy Statement regarding natural gas pipeline certificates. FERC announced this potential policy change of its current policies for determining if a proposed natural gas pipeline meets the review standard of public convenience and necessity. Specifically, FERC sought information on its current certificate policies, the certification application and the scope of its environmental review—all part of the certificate process that

FERC has jurisdiction over through the Natural Gas Act. The status of this policy announcement and its effect on the natural gas industry is still pending, as FERC has extended the time for comments regarding its inquiry.

1.8 Unique Aspects of the Power Industry

In the U.S., federalism refers to the sharing of governmental authority between the federal and state governments. The federal government has power to create laws involving national interests. State governments may pass, enforce and interpret laws so long as they do not violate the U.S. Constitution. Authority over the electric utility industry is shared between the federal and state governments. In general, the federal government has authority over transmission rates and service, and wholesale sales of energy and ancillary services in interstate commerce. The states have authority over retail distribution and sales of energy to retail customers. For generation, states generally have authority over the certification and siting of new generation facilities, but depending on how the output of the generation is sold, either the Federal Energy Regulatory Commission or a state commission would have authority over the output. For transmission siting, the federal government in most cases has no authority regarding siting. The states do have authority regarding siting, but the states vary widely in how they regulate this activity. In general, entrants in the American power industry should be mindful of the role that both state and federal governments will play regarding their assets, and how those roles may shift depending on particular circumstances.

2. Market Structure, Supply and Pricing

2.1 Structure of the Wholesale Electricity Market

The wholesale electricity market is regulated by the Federal Energy Regulatory Commission ("FERC" or "Commission") under the Federal Power Act ("FPA"). The FPA requires that all rates for wholesale sales of electric energy in interstate commerce shall be just and reasonable and not unduly discriminatory or preferential.

Two related but distinct sections of the FPA govern FERC's adjudication of just and reasonable rates: section 205, codified at 16 U.S.C. § 824(d), and section 206, codified at 16 U.S.C. § 824(e). Section 205 requires public utilities to file their rates with the Commission. Section 206 empowers FERC to fix a new rate upon a determination that the existing rate is not just and reasonable or is unduly discriminatory or preferential. Id. § 824e(a). An investigation under section 206 may arise upon complaint or on FERC's own initiative.

In the case of wholesale rates set by the marketplace instead of on a cost-of-service basis, FERC satisfies its regulatory obligation by granting sellers authority to make sales at market-based rates only upon a demonstration that the seller lacks market power. FERC also engages in oversight over wholesale markets by regulating the terms and conditions of wholesale markets under FPA sections 205 and 206 and engages in wide-ranging analysis of wholesale markets to ensure they produce just and reasonable rates.

Copies of 16 U.S.C. §§ 824(d)-(e) are here:

1. https://www.gpo.gov/fdsys/pkg/USCODE-2011-title16/pdf/USCODE-2011-title16-chap12-subchapII-sec824d.pdf

2. https://www.gpo.gov/fdsys/pkg/USCODE-2011-title16/pdf/USCODE-2011-title16-chap12-subchapII-sec824e.pdf

There is not a single homogeneous wholesale market structure in the United States. Wholesale market structures differ by region. While market-based pricing of wholesale sales is widely employed, there are still limited instances in which wholesale prices are set using regulated, cost-of-service principles.

In regions governed by "organized" energy markets run by Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs"), wholesale prices are set by the centralized market using locational marginal pricing (or "LMP") under security-constrained economic dispatch principles. LMP sets the marginal cost of energy for that location (or node) and establishes the financial value of congestion and losses. The security-constrained economic dispatch should reflect the least-cost manner of providing an additional megawatt ("MW") to each node.

In regions not governed by an RTO/ISO, wholesale sales are also made on a competitive basis, largely relying on bilateral transactions wherein the price is set between the buyer and seller, and not by a centralized market.

In the RTO/ISO markets, energy markets are the norm, but some also have formalized capacity markets. RTO/ISO capacity markets are run outside the energy market and serve to ensure resource adequacy through competitive auction-style acquisitions of capacity.

While most wholesale sales are made on a competitive basis with prices set in the market, some cost-of-service rates are still used in limited instances. In RTOs/ISOs, a seller may be mitigated to cost-based benchmarks in times when transmission constraints stifle competition in a particular area. Outside of RTO/ISO markets, some sellers have not been granted market-based rate authority by FERC in markets in which they have high market shares (this is usually the case for vertically-integrated utilities in their home markets). Sales in those instances would have to be made under cost-based tariffs on file with the FERC.

2.2 Imports and Exports of Electricity

According to the U.S. Energy Information Administration, in 2016 alone, the United States imported 65 million MW hours of electricity from Canada and 4.4 million MW hours from Mexico. In that same time period, the United States exported 2.6 million MW hours to Canada and 6.6 million MW hours to Mexico.

Exports of electricity from the United States to a foreign country are regulated and require authorization under section 202(e) of the FPA (16 U.S.C. § 824a(e)). The process for exporting energy from the United States is regulated by the U.S. Department of Energy.

Imports of electricity from a foreign country into a state are not regulated by the FERC or DOE. See 16 U.S.C. § 824a(f). The state into which electricity is imported regulates that electricity.

2.3 Supply Mix for the Entire Market

According to the U.S. Energy Information Administration as of 2017, using kilowatthours (kWh) as the measure, the following is the relative contribution of each major fuel source to power production. See https://www.eia.gov/tools/faqs/faq.php?id=427&t=3

Natural Gas – 31.7%
Coal – 30.1%
Nuclear – 20%
Hydro – 7.5%
Wind – 6.3%
Solar – 1.3%
Geothermal – 0.4%

Other Sources (Imports, Diesel, Tidal, Biofuel, Biomass) – 2.7%

2.4 Principal Laws Governing Market Concentration Limits

Wholesale market concentration is regulated by several federal government agencies.

FERC is the central regulatory authority for ensuring that wholesale markets remain competitive. As discussed below, FERC uses various market share and concentration analyses to determine if a particular seller lacks market power and should be permitted to make market-based sales. The wholesale market share screen measures whether a seller has a dominant position in the market in terms of the number of megawatts of uncommitted capacity owned or controlled by the seller, as compared to the uncommitted capacity of the entire market. A seller whose share of the relevant market is less than 20% during all seasons passes the market share screen. The pivotal supplier screen evaluates the seller's potential to exercise market power based on the seller's uncommitted capacity at the time of annual peak demand in the relevant market. A seller satisfies the pivotal supplier screen if its uncommitted capacity is less than the net uncommitted supply in the relevant market. Failing either screen creates a rebuttable presumption that the seller has horizontal market power. If a seller passes both screens, however, there is a rebuttable presumption that it does not possess horizontal market power.

FERC also regulates wholesale market concentration through its oversight of mergers and acquisitions. Under section 203 of the FPA, Commission authorisation is required for public utility mergers and consolidations and for public utility acquisitions of jurisdictional facilities. Section 203(a) provides that the Commission will approve such transactions if they are consistent with the public interest. The Commission has stated that it will consider three factors when analysing a proposed merger: the effect on competition, the effect on rates, and the effect on regulation. The Energy Policy Act of 2005 ("EPAct 2005") added the further requirement that the Commission determine whether a proposed transaction would result in cross-subsidisation, and if so, whether the resulting cross-subsidisation would be consistent with the public interest. When analysing the horizontal impacts of a proposed transaction, FERC relies on the Herfindahl-Hirschman Index ("HHI") to determine whether the proposed transaction will increase market concentration beyond certain threshold levels.

Mergers and acquisitions in the energy industry are often also reviewed by the Department of Justice ("DOJ") or the Federal Trade Commission ("FTC"). DOJ and FTC generally follow their 2010 Horizonal Merger Guidelines to determine when a proposed transaction will adversely affect competition such that some form of mitigation is necessary. These guidelines can be found at: https://www.justice.gov/atr/public/guidelines/hmg-2010.pdf

FERC has oversight over mergers between public utilities and over acquisitions of jurisdictional facilities. Even when FERC will review a transaction, DOJ/FTC authorisation may still be required.

FERC does not currently use static market share thresholds to determine when M&A transactions may have an anti-competitive effect. FERC instead uses the HHI measures to determine if the proposed transaction would increase market concentration beyond acceptable levels. The HHI is a widely accepted measure of market concentration, calculated by squaring the market share of each firm competing in the market and summing the results. The HHI increases both as the number of firms in the market decreases and as the disparity in size between those firms increases. All three agencies—the DOJ, FTC, and FERC—use HHI to assess market concentration. While FERC places great emphasis on HHI screen thresholds to signal possible anti-competitive outcomes, DOJ and FTC are generally thought to take a less constrained view, and may consider factors well beyond market concentration as measured by the HHI. In addition, state utility commissions often have jurisdiction to review utility M&A transactions, but their primary concern is generally the impact on the retail ratepayer, not the wholesale market.

Along with the HHI thresholds, as discussed above, the Commission adopted two indicative screens, the wholesale market screen and the pivotal supplier screen, to identify sellers that raise no horizontal market power concerns and can otherwise be considered for market-based rate authority.

2.5 Agency Conducting Surveillance to Detect Anti-Competitive Behaviour

FERC is the primary regulatory agency with oversight responsibility for the competitiveness of the wholesale electricity markets. Other federal agencies may also have jurisdiction over certain types of anti-competitive behaviour, including traditional antitrust violations or criminal behaviour.

Congress addressed anti-competitive behavior in EPAct 2005. That legislation provided for significant civil penalties for violations of various sections of the FPA, and augmented FERC's anti-manipulation authority by expressly prohibiting manipulative acts in connection with jurisdictional transaction by "any entity." EPAct 2005 created section 222 of the FPA, codified at 16 U.S.C. § 824v.

In addition, FERC's Anti-Manipulation Rule implements Section 222 of the FPA as created by EPAct 2005. See 18 C.F.R. § 1c. Under the Anti-Manipulation Rule, it is illegal for any entity, directly or indirectly to: (1) use or employ any device, scheme, or artifice to defraud; (2) to make any untrue statement of a material fact or to omit to state a material fact necessary in order to make the statements made not misleading; or (3) to engage in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity. The Commission outlined the elements of the Anti-Manipulation Rule in Order No. 670, explaining that it prohibits an entity from: (1) using a fraudulent device, scheme, or artifice, making a material misrepresentation or omission, or engaging in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity; (2) with the requisite scienter; (3) in connection with the purchase or sale of natural gas or electric energy (or the transportation or transmission of such) subject to the jurisdiction of the Commission.

16 U.S.C. § 824v can be found here: https://www.gpo.gov/fdsys/pkg/USCODE-2011-title16/pdf/USCODE-2011-title16-chap12-subchapII-sec824v.pdf

18 C.F.R. § 1c can be found here: http://www.ecfr.gov/cgi/t/text/text-idx?c=ecfr&sid=5526e11f6adf72bcb980bf480b29c88e&rgn=div5&view=text&node=18:1.0.1.1.3&idno=18 –

Additional guidance on the application of FERC's Anti-Manipulation Rule can be found in FERC Order No. 670. See http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=10932497

The FERC Office of Enforcement ("OE") has the responsibility for market surveillance and enforcement. OE is divided among four groups: Division of Investigations ("DOI"), Division of Audits and Accounting, Division of Energy Market Oversight, and the Division of Analytics and Surveillance. The Department of Investigations' staff initiates investigations from information received through a variety of sources, even self-reported information.

EPAct 2005 created section FPA 316A, 16 U.S.C. § 825o-1, which provided for maximum civil penalties of USD1 million per day, per violation, for any violation of the FPA, or the Commission's regulations.

In addition, ISO and RTO employ market monitors to address market manipulation. They play an important role in enhancing the performance of competitive wholesale electric markets. Market monitors monitor compliance with market rules, recommend changes in market design and market rules, report on market functioning on a regular basis for transparency, recommend mitigation measures to prevent exercises of market power, and refer manipulative actions to a government enforcement agency. Furthermore, FERC's regulations in 18 C.F.R. § 35.41(b) explicitly provide that furnishing false information to a market monitor is actionable by FERC.

3. Climate Change Laws and Alternative Energy

3.1 Principal Climate Change Laws and/or Policies

The United States has laws that affect climate change at both the federal and state levels. On the federal level, the United States targets to reduce greenhouse gas emissions to 17% below 2005 levels by 2020 and 28% below 2005 levels by 2025 under the United Nations 2015 Paris Agreement. However, the United States is in the process of removing itself from the Paris Agreement, which will be completed in 2020. The United States has failed to pass any comprehensive climate legislation at the federal level, but there are a number of laws that can be used to enact climate change policies.

The main federal laws that relate to climate change and the power industry are the Clean Air Act (42 U.S.C. § 7401 et seq.), the Energy Policy Act (42 U.S.C. §13201 et seq.), the

Consolidated Appropriations Act, 2016 and the Energy Independence and Security Act (42 U.S.C. § 152 et seq.). The Clean Air Act is designed to control air pollution on a national level, requiring the Environmental Protection Agency ("EPA") to develop and enforce regulations to protect the general public. Under a 2009 opinion, the EPA is required to regulate greenhouse gases from motor vehicles. The Energy Policy Act provides tax incentives and loan guarantees for, among other things, nuclear power, clean coal and renewable energy facilities. The Consolidated Appropriations Act, 2016 provided an extension for the Production Tax Credit and the Investment Tax Credit, the main federal incentives for renewable energy development. The Energy Independence and Security Act provides for among other things, (i) research in solar, geothermal energy and carbon capture technologies, (ii) a biomass renewable fuel standard and (iii) assistance to foreign countries for developing clean technologies

Even though there is not a comprehensive climate change policy at the federal level, many states have enacted legislation to address climate change. There are fourteen (14) states that have a target or goal to reduce greenhouse gases. To accomplish such goals, states take one of two approaches. The first is a market-based approach while the second relies on states setting emissions performance standards that electricity producers from such state must meet. In the market-based approach, a state or group of states set a carbon cap, which is then reduced on an annual basis. Through state legislation, the participants create a market for allowances that participants can then trade in an open market place. The carbon emission setting approach imposes mandatory limits on new or expanded electric generating facilities. Enforcement of the emission standards are usually performed through permitting, however, some states require that noncomplying facilities must purchase offsets.

https://unfccc.int/process/the-paris-agreement/status-of-ratification

http://www4.unfccc.int/submissions/INDC/Submission%20Pages/submissions.aspx

https://www.epa.gov/laws-regulations/summary-clean-air-act

https://www.epa.gov/laws-regulations/summary-energy-policy-act

https://www.congress.gov/bill/114th-congress/house-bill/2029/text

3.2 Principal Law and/or Policies Relating to the Early Retirement of Carbon-Based Generation

The Clean Power Plan, a set of regulations promulgated by the EPA under the Clean Air Act, is the primary set of federal regulations aiming to limit carbon dioxide emissions from power plans. The Clean Power Plan established state-by-state targets for carbon emission reductions and a framework for states to meet such targets. Because of the differences among states in energy resources, potential for carbon emission reductions and state policies, each state was required to meet a different target for carbon dioxide reduction, with an overall goal of reducing carbon dioxide emissions to thirty-two percent (32%) below 2005 emission levels. However, the Supreme Court stayed the implementation of the Clean Power Plan and President Trump's administration has begun the process to repeal the Clean Power Plan.

At the state level, market-based and regulatory based legislation has been implemented to combat the use of carbon dioxide emitting fuel sources. Nine northeastern and mid-Atlantic states entered into a market approach and formed the Regional Greenhouse Gas Initiative (RGGI), which provides an aggregate cap for carbon dioxide emitted from energy generation facilities operated in the participating states. Through laws in each participating state, there is a cap of carbon dioxide emissions, which is then reduced by 3% each year until 2020. The states participating in the RGGI sell emission allowances through auctions and then invest the proceeds from such auctions in energy efficiency and renewable energy resources. Facilities in the participating states can trade emission allowances, as needed, thereby creating a market for emission allowances. Although the RGGI only covers electric generating facilities, California has a similar program that covers all facilities that emit or distribute fossil fuels with emissions of at least 25,000 metric tons CO2-equivalent or greater.

Additionally, six states have emission standards or incentives for new power generating facilities. These states utilise legislated performance standards to limit the amount of carbon dioxide that can be generated from new power generating facilities. Enforcement of the emission standards are usually performed through permitting, however, some states require that noncomplying facilities must purchase offsets. Another type of state legislation that reduces carbon dioxide and therefore the use of coal are demand-side energy efficiency programs. Mandatory energy efficiency programs have been implemented in 24 states with two states having voluntary targets. By implementing these efficiency programs, the states reduce the overall load of a state thereby reducing the need for electricity from coal power plants.

https://www.epa.gov/ghgemissions/endangerment-and-cause-or-contribute-findings-greenhouse-gases-under-section-202a-clean

https://www.epa.gov/energy-independence

https://www.rggi.org/program-overview-and-design/elements

Many RTOs and ISOs have protocols for retiring generating units, so that units that are needed for reliability do not retire before mitigation can be put in place. Units that are required to run past their desired retirement date often receive compensation in the form of "reliability must run" contracts. State utility commissions generally govern cost recovery of any unrecovered investment in the generating facility at the time of retirement.

3.3 Principal Law and/or Policies to Encourage the Development of Alternative Energy Sources

The largest federal incentive used to encourage the development of alternative energy sources are the Investment Tax Credit (ITC) and the Production Tax Credit (PTC). Each of the programs can be used for a large number of technologies including, among others, wind, solar photovoltaic, municipal solid waste, and geothermal projects. However, the owner of the project must elect to choose one tax credit or the other. The PTC is a ten-year federal credit that provides inflation adjusted tax credits to taxpayers based upon the amount of energy produced from a facility utilising a qualified technology that the taxpayer sells to unrelated parties during the taxable year. The PTC is based on a $0.015 per kWh in 1993 dollars and adjusted for inflation. However, the PTC is in the process of being phased out, leading to a 40% reduction of the credit in 2018 and a 60% reduction in the credit in 2019. The ITC is a tax credit that is based on the total up front capital expenses used to build a facility that uses a qualifying technology, rather than the amount of energy generated by such facility. The ITC, depending on the technology used, is between a 10% and 30% tax credit on the capital expenses used. Similar to the PTC, the ITC is being phased down on an annual basis. Depending on the technology, after 2022, the largest tax credit a developer can receive is 22%, while some technologies will no longer qualify for the ITC.

Twenty-nine states plus the District of Columbia have a Renewable Portfolio Standard (RPS). A RPS is the legislative mechanism states use to require utilities and other retail electricity suppliers to provide renewable and alternative energy sources to their customers. A RPS requires that the utility or retail electricity supplier provide a specified percentage of its energy delivered to retail customers to be from renewable and/or alternative sources. The specified percentage is then stepped up on a yearly or biannual basis until such percentage meets the target. In order to satisfy a RPS, utilities and retail electricity suppliers subject to the RPS can use energy produced from specified lists of sources. These sources usually include solar photovoltaic, wind, hydro, biomass and geothermal but in some state's can also include, among others, nuclear, poultry litter-to-energy or oceanic and tidal sources. Electricity providers are typically required to pay a compliance payment if they do not hit the required percentage in any given year.

The property assessed clean energy (PACE) programs are locally established programs that provide financing for renewable energy improvements on commercial and residential private property. These programs allow property owners to finance the up-front cost of renewable energy improvements on their property and repay the costs through voluntary assessments over a period of 10 to 20 years. The assessment runs with the property rather than an individual or company and assessments are paid through the land owner's tax bill. Because the financing is secured by the land, any subsequent owner must be willing to undertake the obligations of the property owner upon as sale or transfer of the land.

https://www.nyserda.ny.gov/All-Programs/Programs/Clean-Energy-Standard

http://pacenation.us/

https://www.law.cornell.edu/uscode/text/26/subtitle-A/chapter-1/subchapter-A/part-IV/subpart-E

https://www.law.cornell.edu/uscode/text/26/subtitle-A/chapter-1/subchapter-A/part-IV/subpart-D

4. Generation

4.1 Principal Laws Governing the Construction and Operation of Generation Facilities

The applicability of federal and state environmental laws to the construction and operation of renewable energy generation facilities depends on the type of generation (solar, wind, biomass, etc.) and the scope of the environmental impacts that may be caused during construction and/or operation. Depending on these and other factors, the most significant potentially applicable environmental laws and permits may include:

- Dredge and Fill Permit under Section 404 of the Clean Water Act for impacts to federal jurisdictional waters (including wetlands) from the U.S. Army Corps of Engineers. If expected impacts are below certain thresholds, a general permit (called a Nationwide Permit) may be all that is needed. Many states also regulate waters that are not subject to federal jurisdiction, and thus impacts to such state waters may also require state permits.
- Coverage under the General Storm Water Construction Permit under the Clean Water Act for discharges of construction-related storm water from the state agency with delegated authority to regulate storm water discharges. Coverage under the General Permit requires preparation

and implementation of a Storm Water Pollution Prevention Plan.
- Incidental Take Permit under the Endangered Species Act for impacts to federally endangered or threatened species or their habitat (if impacts to habitat are sufficiently significant) from the U.S. Fish and Wildlife Service and/or the National Marine Fisheries Service (depending on the species). To support an application for an ITP, the applicant must prepare a Habitat Conservation Plan identifying minimisation, avoidance, and mitigation measures that the applicant will take to reduce impacts to listed species. In addition, many species have protected status under state laws, and depending on the state, additional permitting requirements may apply for impacts to state-listed species.
- Eagle Take Permit under the Bald and Golden Eagle Protection Act for impacts to bald and golden eagles from the U.S. Fish and Wildlife Service during construction (e.g., noise-related disturbance to nesting eagles) or operation (e.g., wind turbine related deaths or injuries). Eagles are also frequently protected at the state level and thus require coordination with state wildlife agencies as well.
- Prevention of Significant Deterioration Construction Permit and Title V Operating Permit under the Clean Air Act for the emission of regulated pollutants during operation from the U.S. Environmental Protection Agency or a state with delegated authority.

In addition, depending on the ownership of and zoning for the land where the project is planned, federal, state, or local land use approvals may be needed to support construction and operation of the project.

- If the project is on federal land managed by the Bureau of Land Management, a right-of-way will be needed from the BLM to allow the project to be built. BLM rights-of-way frequently incorporate conditions that the applicant must comply with to minimise environmental impacts of the project.
- If the project will be built on private land but will need to be rezoned or would be considered a “conditional use” under state or local zoning laws, a conditional use permit or special use permit may be needed. Frequently, these land use permits incorporate additional environmental conditions that the permittee must comply with during construction and operation.

Finally, if the project needs one or more of the permits identified above, additional environmental review may be triggered under other federal and state authorities, as follows:

- National Environmental Policy Act and/or state counterparts (e.g., California Environmental Quality Act, Washington State Environmental Policy Act, etc.). NEPA is triggered if there is a “federal nexus” – i.e., the project will require a “major federal action” to support construction or operation. For example, if a project will impact federally jurisdictional wetlands and thus need a permit from the U.S. Army Corps of Engineers under Section 404 of the Clean Water Act, NEPA analysis will be required. NEPA requires the lead federal agency to complete a document identifying and evaluating the impacts to the human environment that are expected to be caused by a project, through preparation of an Environmental Assessment or a more detailed Environmental Impact Statement, depending on the scope of the project and its impacts.
- National Historic Places Act. As part of a project’s NEPA compliance, consultation with the State Historic Preservation Office under the National Historic Places Act is required to assess impacts to culturally sensitive areas that may be eligible for listing on the National Registry of Historic Places.

4.2 Regulatory Process for Obtaining All Approvals to Construct and Operate Generation Facilities

The regulatory process that applies to the approvals for a given project will depend on the scope of permits that are required, which is in turn driven by the scope of the environmental impacts that may be caused during construction and/or operation. Before an application is filed, project developers often meet with the relevant agency to have a pre-application meeting and to set a schedule for the permitting process, which helps ensure the agency agrees with the terms of the application and expedite processing once submitted.

Many federal and state permits include opportunities for public notice and comment. Even if an underlying permit does not require public notice and comment, the accompanying NEPA (or state equivalent) analysis may provide an opportunity for public involvement if the lead agency has determined that an Environmental Impact Statement should be prepared.

The timing for receipt of approvals also depends on the level of public involvement and complexity in the permitting required, ranging from as little as six months to over two years for projects that trigger NEPA and require multiple federal approvals.

4.3 Terms and Conditions Imposed in Approvals to Construct and Operate Generation Facilities

Permits for renewable generation facilities can include a broad range of terms and conditions, depending on the scope of the environmental impacts that the project is expected to cause. These terms can include measures to mitigate environmental impacts, including dust mitigation requirements during construction, wildlife avoidance and mitigation measures to reduce or compensate for impacts to protected species, traffic mitigation plans for construction-related increases in vehicle use, federal and state jurisdictional water-related avoidance and compensatory mitigation requirements, development of plans to address unexpected discoveries of cultural resources during construction, and best management practices to minimize storm water construction-related impacts are among the types of conditions that may be imposed in federal and state permits.

Although it depends on the type of permit, to amend or relax the terms or conditions of a permit may require the same amount of processing, including public review and comment, as the original permit application process. Ensuring that the original permit terms are feasible is therefore crucial to the permitting process to avoid potentially significant delays associated with seeking amendments to applicable permits.

4.4 Proponent's Eminent Domain, Condemnation or Expropriation Rights

If the proponent for the construction and operation of a generation facility has been delegated eminent domain powers by the applicable state, then said proponent can generally use eminent domain powers to obtain surface access and use rights for a generation facility. Generation facility proponents that have been delegated these rights are typically public utilities. Even where a proponent has been delegated eminent domain powers, there is often a need to establish the necessity of the project and that the project is in the public interest. Note that some states have enacted legislation to prohibit or limit the ability of generation facility proponents to exercise eminent domain rights to acquire real estate interests for the construction and operation of generation facilities. Rights to the surface of land for the purposes of constructing and operating a generation facility are typically acquired through arm's length transactions without the use of eminent domain powers. When eminent domain powers are used, the proponent exercising such powers is required to provide the landowner with just compensation based on the value of property condemned, plus any damages to the remainder of the property that is not condemned. This determination is based on the fair market value of the rights taken considering the highest and best use of the property. Common appraisal methods used to arrive at the just compensation include the comparable sales method and income method. Please note that all of the foregoing varies on a state-by-state basis, so reference to the laws of particular states is recommended.

4.5 Requirements for Decommissioning

Decommissioning requirements for a given project are heavily dependent on the jurisdiction where they are planned and the governmental agencies that oversee their construction and operation. Some jurisdictions require formal decommissioning plans and financial security to be implemented as conditions of land use or other permits for the project, and may even prohibit the salvage value of project equipment from being accounted for in decommissioning costs.

5. Transmission

5.1 Regulation of Construction and Operation of Transmission Lines and Associated Facilities

5.1.1 Principal Laws Governing the Construction and Operation

States have primary authority over the siting and construction of electric transmission lines and associated facilities. The federal government was granted an exception with the enactment of the Energy Policy Act of 2005, which declared it a national policy to increase coordination among applicable Federal agencies regarding the siting of electric transmission facilities. *[See, EPAct of 2005, https://www.gpo.gov/fdsys/pkg/PLAW-110publ140/pdf/PLAW-110publ140.pdf]*.Accordingly, section 1221 of the EPAct of 2005 added section 216 to the FPA providing regulations for the siting of interstate electric transmission facilities under narrow and specific circumstances. Through the EPAct of 2005, the U.S. Department of Energy ("DOE") delegated its coordination responsibility to FERC. While states still retain their chief siting authority, an applicant may turn to FERC if the states withhold approval of an application for more than a year. Under certain narrow circumstances, an applicant may turn to FERC for a siting permit entirely. However, FERC may only use its authority if the proposed transmission line was within a "corridor" designated by the DOE as a National Interest Electric Transmission Corridor (i.e., an area of transmission congestion that adversely affects consumers).

5.1.2 Regulatory Process for Obtaining All Approvals to Construct and Operate Transmission Facilities

A transmission company seeking to construct and operate an electric transmission line and associated facilities must first obtain applicable state and federal certifications. As part of the pre-filing process, a company must consult with the state agencies that possess authority to grant necessary permits and approvals in the siting process. Typically, a transmission company must acquire a Certificate of Public Convenience and Necessity from the applicable state public service commission or another designated state siting authority. In addition, approvals are often required from state and local levee and drainage districts, state natural resources departments, environmental protection and cultural heritage agencies.

At the federal level, transmission companies are required to obtain approvals from the appropriate Federal agencies, such as the U.S. Fish and Wildlife Service, the Federal Aviation Administration, the U.S. Army Corps of Engineers, and the State Historic Preservation Offices regarding endangered species, wetlands, and archaeological sites and to follow all applicable Federal laws and regulations to avoid or to reduce harmful impacts to these resources. As discussed earlier, in most instances, FERC has no authority regarding the siting and construction of electric transmission lines. However, assuming an applicant can meet the narrow exceptions to this general rule and can qualify to have FERC hear its siting application, upon submission of an application for a certification to construct and operate a transmission line, FERC issues a Notice of Intent to prepare an environmental assessment ("EA") or an environmental impact statement ("EIS"). The NOI requests comment from interested parties on the scope of FERC's environmental review. After closure of the comment period, FERC may either prepare an EA or a draft EIS to compile its findings and recommendations for the proposed transmission line project. FERC references its findings and recommendations in its Final EIS or its final order either granting or denying the application. The length of the regulatory process is dependent upon the size of the project and the level of coordination between the applicant, FERC and additional regulatory agencies.

5.1.3 Terms and Conditions Imposed in Approvals to Construct and Operate Transmission Facilities

A state or local agency may condition its approval with any mandatory terms that the agency deems necessary for the safety and protection of the state lands. Examples of conditions imposed in approvals to construct and operate a transmission line and associated facilities include: (1) obtaining county approvals for specific project activities; (2) requiring mitigation measures for the protection of wildlife; or (3) affording the state or local agency some limited, independent jurisdiction over the operation of the project.

5.1.4 Proponent's Eminent Domain, Condemnation or Expropriation Rights

A state will often vest a transmission developer with eminent domain authority. When eminent domain powers are used, the proponent exercising such powers is required to provide the landowner with just compensation based on the value of property condemned, plus any damages to the remainder of the property that is not condemned. This determination is based on the fair market value of the rights taken considering the highest and best use of the property. Common appraisal methods used to arrive at the just compensation include the comparable sales method and income method. Please note that all of the foregoing varies on a state-by-state basis, so reference to the laws of particular states is recommended.5.1.5 Transmission Service Monopoly Rights

Federal law does not grant transmission-owning public utilities rights to build transmission lines or provide transmission service in a specified geographical territory. Moreover, in July 2011, FERC issued Order No. 1000 which increased transmission development which eliminated the contractual right of an incumbent transmission owner to construct, own, and propose cost recovery for any new transmission project that is: (1) located within its service territory; and (2) approved for inclusion in a transmission plan developed through the Order No. 890 planning process. However, as Order No. 1000 and its progeny make clear, the transmission construction process remains subject to state-specific siting and permitting requirements *[See, Order No. 1000 at P 227.]*. Thus, while federal law may not grant exclusive rights for a transmission-owning public utility to construct or provide transmission service in a defined area, state laws and regulations may provide such rights.

5.2 Regulation of Transmission Service, Charges and Terms of Service

5.2.1 Principal Laws Governing the Provision of Transmission Service, Regulation of Transmission Charges and Terms of Service

FERC has exclusive jurisdiction over the transmission of electric energy in interstate commerce, and over the sale of electric energy at wholesale in interstate commerce, and over all facilities for such transmission or sale of electric energy. The principal laws governing these activities can be found at 16 U.S.C. 824, 824(d), and 824(e).

For a detailed listing of these laws, go to: https://www.gpo.gov/fdsys/pkg/USCODE-2011-title16/pdf/USCODE-2011-title16-chap12-subchapII.pdf.

5.2.2 Establishment of Transmission Charges and Terms of Service

As discussed below, FERC regulates the rates, terms, and conditions of service for transmission. The FPA requires that charges for transmission rates are to be just and reasonable, and that no public utility may grant undue preference or advantage to any entity or charge different rates to similarly situated transmission customers.

Under Sections 205 and 206 of the FPA, the utility initiates the regulatory process under which rates and terms of service are established. The utility must show that the new, proposed rates are just and reasonable. The new rate applies as of the "effective date"—i.e., the date that the Commission permits the rate to become effective. Section 205 generally requires that a utility file a change to a rate, term, or condition at least 60 days prior to the date the utility anticipates that the change will go into effect, but the Commission may waive such notice period for good cause. Section 206 generally affords FERC the ability to specify a new rate, term or condition pursuant to a complaint by another entity or on its own accord. Additionally, the Commission may suspend the effectiveness of a change for up to five months beyond the time when such change would otherwise go into effect. When a new rate goes into effect, the new rate may also be in effect subject to refund if additional procedures are necessary to determine the just and reasonable rate.

Most utilities initiate a formula rate. The formula is the rate, and FERC approval is needed to change the rate. In determining the just and reasonable rate for service, the following concepts generally apply:

1. Revenue Requirement – the amount of revenue that affords the utility the opportunity to recover its prudently incurred costs, plus a reasonable return on investment.

2. Cost Functionalisation – the assignment of costs to the business unit (generation, transmission, and distribution) that incurred them.

3. Cost Classification – the assignment of costs to the customer class using a specific service.

4. Cost of service – the cost of service reflects a "test period." This test period is divided into two categories: the base period and the adjustment period. The base period reflects the most recent 12 consecutive months for which data is available, but the last day of the base period may not be more than 4 months prior to the filing date. The adjustment period reflects up to 9 months immediately following the base period, where adjustments can be made for predicted changes in revenue and costs, which are known and measurable with reasonable accuracy at the time of the filing and which will become effective within the adjustment period. Under the Commission's regulations cost of service is determined by this formula: E + d + T + (V-D*R), which reflects:

E = operating expenses
d = depreciation expenses
T = taxes
V = gross value of property
D = accrued depreciation
R = overall rate of return ("ROR")

"E" is the Operation & Maintenance ("O&M"), purchased gas, transportation and compression by others, employee salaries and benefits, advertising, research and development ("R&D"), and regulatory affairs expenses. These must be prudently incurred.

"d" is the loss, which is due to all factors causing the ultimate retirement of the property. The usual depreciation issue in a rate case involves the derivation of the depreciation rate corresponding to economic life (as opposed to physical life).

"T" are the tax expenses associated with cost of service revenues and does not reflect actual taxes paid.

(V-D*R) is the overall return on cost of capital. "V" represents the original cost of plant plus working capital. "D" represents depreciation, and "R" is the overall rate of return, which is cost of capital (debt and equity).

Any person aggrieved by a FERC order in a proceeding to which they were a party may request that FERC review its decision on rehearing. By statute, any rehearing request must be submitted within 30 days of the original order; the Commission does not have authority to extend this filing deadline. The Commission has 30 days to act on a rehearing request or it is deemed denied. Frequently, the Commission will issue an order granting the rehearing request for purposes of further consideration; this is not a decision on the merits of the rehearing request, but rather acts as a mechanism to toll the period in which it must conduct its review.

After FERC issues its rehearing order, parties have a right to petition for review of such order to the United States Court of Appeals. The United States Court of Appeals for the District of Columbia Circuit or the U.S. Court of Appeals where the utility has its principle place of business are the most common forums.

5.2.3 Open Access Transmission Service

Transmission service must be provided on an open access and non-discriminatory basis, and FERC has promulgated rules to facilitate this principle.

On April 24, 1996, FERC issues Order No. 888, which required public utilities to provide open access transmission service on a comparable basis to the transmission service they provide themselves. Specifically, Order No. 888 required all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to file open access non-discriminatory transmission tariffs ("OATT") that contain minimum terms and conditions of non-discriminatory service, and permits public utilities and transmitting utilities to seek recovery of legitimate, prudent and verifiable stranded costs associated with providing open access and FPA section 211 transmission service.

In a companion order, FERC issued Order No. 889 at the same time, which established rules governing Open Access Same-time Information System ("OASIS") and prescribing standards of conduct.

On February 16, 2007, FERC issued Order No. 890, which promulgated reforms to the pro forma OATT in the areas of calculation of available transfer capability, transmission planning, and the terms and conditions of open access transmission service.

On July 21, 2011, FERC issued Order No. 1000 to amend its regulations again to remedy opportunities for undue discrimination and address deficiencies in the pro forma OATT that had become apparent since the issuance of Order Nos. 888, 889, and 890.

6. Distribution

6.1 Regulation of Construction and Operation of Electric Distribution Facilities

6.1.1 Principal Laws Governing the Construction and Operation of Electric Distribution Facilities

In contrast to FERC's jurisdiction over the construction and operation of electric transmission facilities at the federal level, the laws governing the construction and operation of electric distribution facilities significantly vary by state. Many state utility commissions have authority over cost recovery for a utility's distribution investments whereas state and local governments and zoning laws impact siting, construction and condemnation rights for distribution facilities.

Interested parties should consult the relevant state laws and regulations governing the construction and operation of electric distribution facilities.

6.1.2 Regulatory Process for Obtaining All Approvals to Construct and Operate Distribution Facilities

The approval process to construct and operate electric distribution facilities significantly vary by state. State laws and regulations generally aim to ensure that electric distribution facilities meet minimum reliability, safety, and operational standards and are sited and operated in compliance with applicable state or local laws. The review of a request to construct and operate an electric distribution facility may require one or more state agencies to examine the physical, environmental, technical, public interest, and economic impacts in deciding whether to approve an electric distribution facility.

In some states, state utility commissions have oversight authority over the siting of and issuance of licenses for the construction and operation of transmission and distribution facilities, zoning for energy facilities and the taking of land for energy facility easements. However, in most states, the state utility commission may only have jurisdiction over cost recovery decisions related to investments made in electric distribution facilities—the state commission would rely on its ratemaking authority rather than a separate process to review electric distribution facility investments.

Note that some states have divisions within the state utility commission that are tasked with ensuring compliance with state environmental laws, while other states have a separate state agency or board tasked with reviewing the environmental impact of any proposed new construction.

Depending on the state agency and review being conducted, public participation and input may be permitted in accordance with applicable state laws and regulations. Depending on the specific state laws in place, a utility may need to provide advance notice regarding a proposed facility and file copies of such plans with the state commission or other appropriate agency. Sometimes state law requires public hearings and sometimes an interested party may request a public hearing after being provided notice. The state utility commission or applicable agency may also solicit public comment on the proposal.

Regardless of the specific process or agencies involved, decisions regarding the review and approval of new electric distribution facilities occur at the state level. FERC will give deference to state utility commission determinations but will step in if there is a question about whether a facility is truly a distribution facility or a transmission facility.

6.1.3 Terms and Conditions Imposed in Approvals to Construct and Operate

The terms and conditions imposed significantly vary depending on the state administrative and regulatory structures. In a state with traditional vertically integrated utilities, a state utility commission typically requires that a utility demonstrate (1) a need, (2) that the facilities are in the public interest, and (3) that the costs recoverable from ratepayers is reasonable. Depending on the state, there may be requirements to avoid or mitigate environmental or cultural resource impacts due to the construction of new distribution facilities.

6.1.4 Proponent's Eminent Domain, Condemnation or Expropriation Rights

Eminent domain, condemnation and expropriation rights vary depending on the regulatory structure established by each state. Generally, the entity proposing to construct and operate electric distribution facilities is a public utility granted eminent domain, condemnation or expropriation rights by virtue of a state statute or state constitution subject to state utility commission review and oversight.

A public utility must provide "just compensation" for the taking of any property pursuant to such eminent domain, condemnation or expropriation rights. The determinants of what is considered just compensation varies by state.

6.1.5 Distribution Service Monopoly Rights

Whether electric distribution entities (utilities) have monopoly rights to provide distribution service depends on the state laws and regulatory structure in the state. Some states authorize exclusive franchise territories for regulated utilities, which are provided for by state legislation.

6.2 Regulation of Distribution Service, Charges and Terms of Service

6.2.1 Principal Laws Governing the Provision of Distribution Service, Regulation of Distribution Charges and Terms of Service

The primary sources of rules and regulations governing electric distribution service include: state legislation, state regulations, and state utility commission rules. State utility commissions typically have exclusive jurisdiction and broad discretion to establish rates, terms and conditions for electric distribution service, so long as the rates are just and reasonable.

6.2.2 Establishment of Distribution Charges and Terms of Service

State utility commissions are granted jurisdiction over ratemaking for electric utility service. The frequency, process, duration, and time-frame for rate base proceedings are jurisdiction-dependent. Typically, a utility will request a change in base rates and the request, along with the utility's supporting evidence, is reviewed by a commission staff. The state utility commission then holds public hearings concerning the reasonableness of such rate, charge, classification, or service. Interested parties may intervene in the proceeding to voice concerns and request additional information. To that end, interested parties and commission staff, and the utility present their formal cases to the state utility commission and file supporting testimony and documents.

Following hearings and briefing by the parties, a commission will then issue a formal ruling. State statutes establish the time-period in which a commission must render a final decision regarding a contested case. Once a state utility commission issues a decision, a utility or other interested party several options for appealing or applying for judicial review of a final decision. For example, some states provide that any person who exhausts all remedies available within an agency and who is aggrieved by a final decision is entitle d to judicial review.

Note that in recent years, in lieu of traditional rate cases, some state utility commissions have adopted alternative rate mechanisms providing for abbreviated and less frequent review, incremental or phased in rate recovery, performance-based rate metrics, and project or investment specific cost recovery through rate riders.

Troutman Sanders LLP
600 Peachtree Street
NE Suite 3000
Atlanta
GA 30308

Tel: 404.885.3000
Fax: 404.885.3900
Email: chris.jones@troutman.com
Web: https://www.troutman.com/energy_law/