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Contents

Phillips Lytle LLP is a premier regional firm with a fast-paced energy practice that provides cutting-edge expertise to a wide range of utilities, developers, owners, pipeline companies, retail energy suppliers and financial partners involved in renewable and other energy projects. The firm has six offices across New York State, as well as offices in Washington, DC, Cleveland, Ohio and Ontario, Canada. Areas of expertise in the energy sector include public service commission and utility regulatory, siting, zoning and environmental, solar, wind, brownfield and landfill renewable energy projects, incentives, bonds and public finance, power purchase agreements, solar leases, microgrids, hydro, biomass, retail energy industry, enforcement and investigations and litigation and dispute resolution. Additionally, with the increase in energy expertise needed beyond the legal realm, the firm established Phillips Lytle Energy Consulting Services to assist clients in navigating the complex policies in the energy industry and provide guidance with respect to project development, transactional support, regulatory counseling to municipalities, and procurement consulting.

Significant research and editorial assistance for the following article was provided by Kathryn Gantley, JD, Cornell Law School (expected May 2020). SUNY New Paltz, BS, 2017.

Authors

David P. Flynn is a partner and the leader of the firm's Energy and Environment Practice teams. With respect to energy, he advises clients on the financing, development and siting of solar, storage and wind projects as well as the licensing of hydropower projects. Mr Flynn regularly speaks on energy topics across New York State and has strong connections with major energy and energy-related organisations, including the American Council on Renewable Energy (ACORE), the Business Council of New York State and Incubators for Collaborating & Leveraging Energy and Nanotechnology (iCLEAN). Mr Flynn graduated with a Juris Doctor degree, cum laude, from the State University at Buffalo Law School.

Dennis W. Elsenbeck is head of Energy and Sustainability for Phillips Lytle Energy Consulting Services. He provides consulting services on a broad range of energy-related opportunities encompassing a forward view of supply, distribution and demand options. In his leadership role with a major US utility for nearly 30 years, he brings to Phillips Lytle insight, analytics and business perspectives on long-term policies and the economic landscape. Mr Elsenbeck assists clients with due diligence and regulatory compliance on energy transactions; regulatory counselling involving Public Service Commission proceedings; energy procurement and utility negotiations involving government entities and municipalities; procurement consulting regarding the reduction of energy costs and review of economic incentives; market-driven integrated resource planning, and identifying commercial and technical issues associated with energy-related opportunities. Mr Elsenbeck graduated with a Masters of Engineering from the University at Buffalo School of Engineering and Applied Sciences. He has his M.B.A. from the University of Rochester, as well as a B.S. in Industrial Engineering Technology from the State University of New York Polytechnic Institute.

Thomas F. Puchner is a partner at the firm and co-team leader of the Energy Practice Team. He focuses on energy and environmental law, with emphasis on regulatory matters, compliance, siting and regulatory litigation. Mr Puchner frequently assists clients with matters before the New York State Public Service Commission (and other state utility commissions), the Federal Energy Regulatory Commission and the New York Independent System Operator and the courts. He regularly advises on matters related to development of renewable energy projects, including zoning approvals and SEQRA compliance, as well as proceedings under Public Service Law Article 10 (generation siting) and Article VII (transmission siting). Mr Puchner graduated with a Juris Doctor degree, magna cum laude, from Vermont Law School.

Kevin C. Blake is an attorney who focuses his practice on energy law, including advising clients on business development issues and the regulation of electricity, natural gas, and telecommunications before state and federal authorities. He has worked on matters before the New York State Public Service Commission relating to regulatory oversight of distributed energy resource providers, electric vehicle charging infrastructure plans, renewable energy credits, energy efficiency programs, and retail supplier evidentiary hearings and complaint proceedings. Mr Blake graduated with a Juris Doctor degree from the University of Colorado Law School.

1. General Structure and Ownership of the Power Industry

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

The US power industry is comprised of four main segments: (i) generation, (ii) transmission, (iii) distribution and (iv) supply. No single entity sets policy for each segment. The US legal system operates according to the concept of shared sovereignty whereby governmental power is divided between state institutions and the federal government. Wholesale power markets and interstate transmission systems are generally governed by federal regulation, while retail power markets and distribution systems are generally governed by state regulation. The contours of state and federal jurisdiction are increasingly being blurred with the advent of new technologies and policies in the evolving 21st-century power industry.

More than any other governmental entity, the individual state utility commissions are the collective architects of the US power sector. State utility commissions are each uniquely structured, but are generally comprised of between three and seven members – who may be elected or appointed – with authority granted by either the state legislature or state constitution to balance policies and preferences related to reliability, affordability, environmental impacts, consumer protection, utility profitability and security. Federal laws and policies governing the power sector are typically implemented by the states, which are layered with independently generated state laws and policies, all of which are distilled and implemented by state utility commissions.

There are two broad classes of utilities in the USA – private investor-owned utilities (IOUs) and public utilities. Within each class are three general types. Private IOUs include vertically integrated, restructured and retail. Public utilities include municipal, co-operative and miscellaneous. Each class and type has a unique historical structure and legal framework.

Vertically integrated IOUs are for-profit shareholder-owned entities that take on the functions of generating, transmitting and distributing electricity to the customer and operate within a defined service territory as a regulated monopoly. In restructured states, the generation function has been opened up to competition such that retail customers can choose to receive energy supply from an alternative supplier, which is transmitted and distributed by the IOU. Restructured IOUs, therefore, operate primarily as transmission and distribution companies. In restructured states, a significant share of power is provided by merchant generators as many IOUs were required or incentivised to sell off most of their generation portfolio to make room for competition. The final category of privately owned utilities is competitive retailers that serve as commodity suppliers and brokers.

Public utilities are comprised of municipal utilities, co-operatives and uniquely structured miscellaneous entities. Municipal utilities are primarily distribution utilities that purchase wholesale power to serve their retail customers. Co-operatives are consumer-owned, not-for-profit entities that can be either distribution-focused businesses that serve member customers, or generation and transmission entities that serve distribution co-operatives. The final category of public utilities includes those that are the product of state and/or federal statute to provide utility services to a particular district, or to market electricity from certain hydroelectric dams.

Integrated IOUs and municipal utilities were the first to emerge in the late 1800s as commercial electrical generation and distribution became widespread. As early utility competition resulted in the construction of parallel redundant power lines and infrastructure, prices plummeted and many utilities were led to bankruptcy. Those that remained were granted a defined geographical service territory in which they could operate as a monopoly in exchange for government regulation under what is known as the 'regulatory compact'.

In the 1930s, President Franklin D. Roosevelt enacted a series of economic measures to counteract the effects of the Great Depression (the 'New Deal'), which included, among other things, passage of the Federal Power Act of 1935 (FPA), the Rural Electrification Act of 1936 (REA), and the creation of certain federally authorised public utilities. The FPA established jurisdictional boundaries between the federal government, which regulates wholesale sales and interstate transmission, and the states, which exercise authority through state utility commissions that oversee retail sales and distribution infrastructure. To promote electrification of underserved rural areas, the REA provided funding to a new class of utility – publicly owned co-operatives. Further electrification efforts were driven by the creation of various congressionally created federal corporations and authorities such as the Tennessee Valley Authority and the Bonneville Power Administration, among others, which generally fall into a broad class of 'miscellaneous' public utilities as each is uniquely structured and governed.

The Public Utilities Regulatory Power Act of 1978 (PURPA), created as a response to the 1970s energy crisis, encouraged conservation and created a market for non-utility power producers by requiring utilities, in certain circumstances, to purchase power generated by qualifying facilities. PURPA was implemented by each state, resulting in a range of regulatory regimes across the country. PURPA paved the way for a series of Federal Energy Regulatory Commission (FERC) orders which promoted open access to transmission facilities (Orders 888 and 889) and independent system operators (ISOs) (Order 2000). Beginning in the 1990s, a number of states further deregulated the vertically-integrated utility sector such that now 16 states and the District of Columbia have active retail choice programmes.

The Energy Policy Act of 2005 (EPAct) represents one of the most significant pieces of federal legislation in the energy sector since the New Deal. It grants FERC enhanced authority to prevent market manipulation and abuse, assess extraordinary civil penalties, approve siting of major transmission projects and implement reliability standards across the county's electric grid.

1.2 Principal State-owned or Investor-owned Entities

The US electric industry is comprised of over 3,000 electricity providers, which include over 2,000 publicly owned utilities, over 800 co-operatives, nearly 200 IOUs and over 200 power marketers. The largest vertically integrated public utility holding companies include Duke, Southern Company, NextEra, Entergy, Dominion and Xcel. The largest restructured public utility holding companies include PG&E, Exelon, Edison International, Consolidated Edison, First Energy, National Grid and Northeast Utilities. The largest retailers include AEP, NRG, EFH, Exelon and ConEd. The largest public power systems, based on net generation, are the New York Power Authority, the Salt River Project and CPS Energy.

A list of IOUS can be found here: www.eei.org/about/members/uselectriccompanies.

A list of large independent power producers and marketers can be found here: https://epsa.org.

A list of co-operatives can be found here: www.electric.coop/our-organization/nreca-member-directory/.

A list of public power entities can be found here: www.publicpower.org/.

1.3 Foreign Investment Review Process

While US utilities or utility holding companies may have foreign ownership, and the US maintains – in principle – an 'open investment' policy, that policy has been tempered by concerns about national security. The 1988 Exon-Florio Amendment to the Defense Protection Act of 1950 authorises the President of the United States, through the inter-agency Committee on Foreign Investment (CFIUS), to review foreign investments that may impact national security, and block investment or impose certain conditions upon credible evidence of a security threat. Such executive decisions are not reviewable by state or federal agencies or courts. The Foreign Investment and National Security Act of 2007 (FINSA) enhances the Exon-Florio Amendment by broadly defining the type of infrastructure transactions covered and adding more stringent rules pertaining to review and investigation of foreign investments. In 2018, Congress enacted the Foreign Investment Risk Review Modernization Act (FIRRMA), which expands the scope of transactions covered under CFIUS's jurisdiction, including certain real estate transactions and investments involving personal data and critical infrastructure. The contours of CFIUS's jurisdiction will evolve as the agency promulgates new regulations implementing its authority under FIRRMA. Nuclear generating facilities are subject to enhanced scrutiny and oversight under the Atomic Energy Act, which generally prohibits issuance of a licence to a foreign person, corporation or government. Nuclear licence transfer requests are reviewed by the Nuclear Regulatory Commission to ensure there is no foreign control of safety-related activities under the licence.

1.4 Principal Laws Governing the Sale of Power Industry Assets

The sale of generation, transmission and distribution system assets, as well as the merger of industry entities generally requires federal and state approval. At the federal level, the sale, lease or disposition of facilities valued at over USD10 million under FERC's jurisdiction that are used for transmission or sale of electric energy in interstate commerce and generation assets making wholesale sales require FERC approval under Section 203 of the FPA. FERC approval is also required to effectuate mergers, acquisitions, or change in control of jurisdictional facilities. In examining such transactions, FERC reviews the effect on competition, rates, cross-subsidisation and whether the transaction is consistent with the public interest. To streamline the processing of certain transactions, FERC issues 'blanket authorisations' for certain dispositions of utility securities and contracts that make it easier for entities to engage in sales and purchases for investment purposes – eg, corporate reorganisations that do not present cross-subsidisation issues, or acquisitions by holding companies of voting securities so long as the acquiring company owns less than 10% of the outstanding voting securities. Additional requirements may apply to transactions involving nuclear generation facilities, which require NRC approval to effectuate an asset transfer. At the state level, state utility commissions are often required to approve acquisition or divestiture of power assets in accordance with state law and regulation.

1.5 Central Planning Authority

The USA does not have a central planning authority that oversees and administers the electricity supply and development of transmission facilities. The USA is broadly divided into three electric grids – the Eastern Interconnection, Western Interconnection and the Electric Reliability Council of Texas. Across those three grids are seven competitive wholesale power markets operated by the following FERC-regulated organisations which provide non-discriminatory access to the transmission network: (i) the New York ISO; (ii) the California ISO; (iii) the Electric Reliability Council of Texas; (iv) New England ISO; (v) PJM Interconnection; (vi) Southwest Power Pool; and (vii) the Midcontinent ISO.

These nine RTOs/ISOs serve two-thirds of the USA. Certain states in the South, Mountain West and Northwest did not join an RTO/ISO and continue to operate independently of the RTO/ISO wholesale markets. RTOs/ISOs are responsible for maintaining operation of the grid, ensure demand meets supply through capacity auctions and market mechanisms, and are governed by FERC tariffs, rules and regulations.

Neither FERC, nor RTOs/ISOs, are responsible for making resource mix decisions, as such authority lies solely with each state. Some states require utilities to perform integrated resource planning and demonstrate how utility infrastructure and investment will meet the needs of customers. Other states impose legislation and/or regulation to mandate or incentivise a certain resource adequacy mix. State-level policy regarding electric supply varies depending on geography, politics and statutory authority, as well as regulatory goals.

The EPAct empowered FERC with authority to ensure the reliability of the bulk power system. FERC certified the North American Electric Reliability Corporation (NERC) as the Electric Reliability Organization charged with developing and enforcing reliability standards for power system operation to ensure reliability through compliance audits, investigations and training.

1.6 Recent Material Changes in Law or Regulation

Material changes in law or regulation occur frequently at the state level, particularly with respect to the emerging role of alternative energy resources. At the federal level, several recent regulations have been promulgated that impact the power industry. FERC's Order 841, issued in February 2018, directed regional grid operators to remove barriers to participation of energy storage in wholesale markets by requiring RTOs/ISOs to establish rules that compensate flexible resources, such as energy storage located on the transmission system, distribution network or behind-the-meter, that can provide value to the capacity, energy and ancillary services markets. FERC asserted its authority under the FPA to enable participation of storage in wholesale markets, setting forth the mechanism by which such resources should be compensated, along with the size and operational requirements guiding development of regional rules. In May 2019, FERC denied requests for rehearing of Order 841 and clarified its decision in Order 841-A by declining to adopt a state opt-out mechanism in light of the benefits storage can provide to the market. It also secured FERC's jurisdiction to regulate storage resources sited on the distribution system or behind-the-meter, and that any impact on retail activities would be legally permissible as a natural consequence of FERC's wholesale market regulation.

In July 2018, FERC issued Order 848 which directed NERC to modify its Critical Infrastructure Protection Reliability Standards (CIP) to broaden and improve mandatory reporting of cybersecurity incidents pertaining to operation of the bulk power system. The Order requires, among other things, reporting not only of incidents that compromise or disrupt systems, but even attempted breaches that could facilitate subsequent efforts to harm the grid. FERC approved the NERC-modified CIP-008-6 in June 2019.

In June 2019, EPA repealed the Obama administration's Clean Power Plan (CPP) and replaced it with the Affordable Clean Energy Rule (ACE). Unlike the CPP, which would have, among other things, established state-specific carbon reduction targets and allowed states to develop their own plans to achieve those targets through implementation of power plant efficiency improvements, fuel-switching and development of zero-emission generation sources, the ACE rule sets guidelines for states to establish unit-specific performance standards at certain coal-fired power plants, and focuses primarily on heat-rate improvements as the best system of emission reduction to reduce carbon emissions, rather than fuel-switching or renewable energy deployment.

1.7 Announcements Regarding New Policies

In April 2018, FERC commenced a new proceeding to review policies governing certification of natural gas transportation facilities under the Natural Gas Act (NGA). In particular, FERC is considering changes to how it reviews the environmental impacts of proposed projects, including whether and to what extent climate impacts – including indirect greenhouse gas emissions – should be considered as part of its determination of whether a project is in the public interest. In June 2019, the U.S. Court of Appeals for the D.C. Circuit ordered FERC to review the downstream greenhouse gas impacts of a pipeline project, citing to requirements in the NGA and the National Environmental Policy Act (NEPA) that FERC review reasonably foreseeable indirect environmental impacts as part of its environmental review obligations. See Lori Birkhead v FERC, No 18-1218 (D.C. Cir. decided 4 June 2019). As the D.C. Circuit and certain FERC Commissioners press for a deeper emissions analysis as part of the decision-making process, future rulings and orders may impact whether or not utilities decide to build new pipeline infrastructure to serve natural gas demand.

As federal environmental regulations continue to make slow, incremental progress, a number of state and local governments are pushing clean energy and climate policies on their own initiative, either to maintain operation of low-carbon generation or to deploy additional clean energy resources. A growing number of states are targeting 100% clean power in the coming decades, including New York, California, Nevada, Hawaii, Washington, New Mexico, Washington, D.C. and Puerto Rico. Furthermore, nearly 120 US cities have declared their intention to procure 100% of their power from renewable energy resources.

A growing number of states have recently enacted legislation creating Zero Emissions Credit (ZEC) programmes designed to subsidise specific non-economic nuclear generation units by compensating them for their carbon-free attributes. The U.S. Supreme Court declined to hear challenges to New York's and Illinois' ZEC programmes, leaving in place the previous rulings from the Second and Seventh U.S. Circuit Courts, which rejected claims that the ZEC programmes intruded in FERC's jurisdiction over wholesale markets. Opponents of ZEC programmes may turn to tariff reforms or other relief from FERC in the coming years as further states implement similarly structured ZEC programmes.

1.8 Unique Aspects of the Power Industry

Investors and market participants should consider the powerful role played by state utility commissions in the architecture and development of the US power industry – particularly as technology applications trend towards smaller-scale distributed energy resources and locational value-based pricing mechanisms.

2. Market Structure, Supply and Pricing

2.1 Structure of the Wholesale Electricity Market

The wholesale electricity market is regulated by FERC, an independent regulatory agency within the U.S. Department of Energy, which implements the FPA, NGA, NGPA and EPAct, among other statutes governing the utility industry. According to Section 201 of the FPA, the wholesale market encompasses all sales of electric energy made to any person for resale (16 U.S.C. § 824). The FPA requires that all rates for wholesale sales of electric energy in interstate commerce be just and reasonable and not unduly discriminatory or preferential.

FERC oversees three methods for setting wholesale rates. First, Section 205 of the FPA, codified at 16 U.S.C. § 824(d), requires public utilities to file their rates with the Commission. Second, Section 206 of the FPA, codified at 16 U.S.C. § 824(e), empowers FERC to, upon complaint or its own investigation, fix a new rate based on the cost of service when it determines that the existing rate is not just and reasonable or is unduly discriminatory or preferential; see www.gpo.gov.

A third method of rate-setting in wholesale markets is by an avoided cost under PURPA. Under PURPA, certain co-generation and small power production facilities that meet specific operating and ownership standards may become qualified facilities, and their power output must be purchased by an electricity utility. An avoided cost is the cost of the power purchased from the qualifying facility that is lower than the cost of the energy that the buying utility would generate itself or purchase from another source. Qualifying facilities are determined by FERC and are commonly limited to sources whose primary energy source is wind, hydro, solar, biomass, thermal or waste resources. These types of wholesale sales receive special rates and regulatory treatment by FERC.

Wholesale rates can also be set by the marketplace through bilateral contracts or power purchase agreements. Before an entity can make sales at such market-based rates, they must obtain market-based rate authority from FERC upon demonstration that the parties lack market power. FERC will review wholesale contracts to ensure that there is adequate competition in the wholesale market guaranteeing that contracts were freely negotiated. FERC also engages in oversight over wholesale markets by regulating the terms and conditions of wholesale market sales under FPA sections 205 and 206.

The US wholesale market is comprised of seven regional, centralised markets called RTOs and ISOs (collectively, RTOs/ISOs), and a patchwork of decentralised geographic areas that operate outside of a defined centralised operating authority.

FERC has encouraged creation of RTOs/ISOs, which have operational control, but not ownership, of transmission assets necessary to administer the wholesale markets. RTOs/ISOs are required to, among other things, maintain operation of the grid, and are subject to enforcement by the NERC (North American Electric Reliability Corporation), which is the FERC-designated electric reliability organisation of the US. The seven RTOs/ISOs serve two-thirds of the USA. Certain states in the South, Mountain West and Northwest did not join an RTO/ISO and continue to operate independently of the RTO/ISO wholesale markets in individual utility control areas where wholesale sales are made on a competitive basis primarily by power purchase agreements and bilateral contracts. The utilities in these control areas remain subject to certain aspects of FERC's jurisdiction, and individual control area operators must co-ordinate amongst themselves to ensure region-wide service reliability. Certain service jurisdictions located in regions not within RTO/ISO regions have recently joined a quasi-RTO/ISO wholesale market called the Energy Imbalance Market.

In the seven RTO/ISO regions, wholesale prices are set by the centralised market using locational marginal pricing (LMP). LMP sets the marginal cost of energy for certain locations (or nodes) based on the operational characteristics of the nodal transmission system itself, incorporating the financial value of congestion, energy losses and the actual energy being transmitted. Security-constrained economic dispatch ensures least-cost energy is provided to each node by dispatching resources based on operational, reserve and transmission constraints to address reliability and system needs.

RTOs/ISOs also run capacity markets outside the traditional wholesale energy market to ensure reliable service through competitive auctions for capacity reserves. In capacity markets, generators will submit bids one year or more in advance to be paid for their willingness to provide electricity at any time within the year. This is done to ensure that there are generators and adequate capacity available at peak demand.

Certain sales within RTOs/ISOs may be made on a cost-of-service basis in limited circumstances where competition does not provide adequate price signals, or in non-RTO/ISO regions where a seller may not have market-based rate authority and thus, must provide power under FERC-regulated prices.

2.2 Imports and Exports of Electricity

Transmission of electricity to a foreign country is regulated by FERC under Section 202(e) of the FPA (16 U.S.C. § 824a(e)). Upon application, the Commission may grant an order to authorise the requested exportation of electric energy. The Department of Energy has authority over emergency authorisations of electricity transmission; see 16 U.S.C. § 824a(c). Further, the Department of Energy oversees and is responsible for granting authorisation of importation and exportation of natural gas.

Electricity imported from a foreign country is not regulated by FERC or the Department of Energy, but by the state within which the importing facility is located; see 16 U.S.C. § 824a(f).

In 2017, the USA imported a combined total of 65 million MWh (megawatt hours) of electricity from Canada and Mexico. Of that total, approximately 9% of that electricity came from Mexico, and 91% from Canada. Meanwhile, the USA exported a total of 9 million MWh of electricity to Mexico and Canada in 2017. Of that total, 65% was exported to Mexico and 35% to Canada. In 2018, the USA imported about 3.6% of its total annual electric energy consumption. For more information, see U.S. Energy Information Administration (EIA).

2.3 Supply Mix for the Entire Market

The EIA estimates that, in 2018, approximately 4,178 billion kWh (kilowatt hours) of electricity was generated by utility-scale power plants of at least 1 MW in capacity, of which approximately 63% came from fossil fuels, with 20% from nuclear energy and 17% from renewable energy sources. An additional 30 billion kWh was generated in 2018 by small-scale solar photovoltaic systems under 1 MW capacity. The following is the relative contribution of each utility-scale fuel source to US electricity generation (see EIA: www.eia.gov/tools/faqs/faq.php?id=427&t=3):

- natural gas – 35.5%;
- coal – 27.4%;
- petroleum – 0.6%;
- nuclear – 19.3%;
- hydro – 7.0%;
- wind – 6.6%;
- solar – 1.6%;
- biomass – 1.5%;
- geothermal – 0.4%;
- other sources – 0.3%.

2.4 Principal Laws Governing Market Concentration Limits

The wholesale market concentration of electricity supply is regulated by a number of federal government agencies, principally FERC. FERC ensures competition in wholesale markets through, among other things, screening and authorising market participants that seek to make wholesale sales of energy, capacity and ancillary services at market-based rates. Negotiated rates will only be upheld if neither party has market power – the ability of one party to set prices above competitive rates due to their unilateral or coordinated ability to leverage undue influence on the market.

Market participants seeking market-based rate authorisation must file an application and receive approval from FERC, which may be granted if the applicant can demonstrate that it lacks, or has adequately mitigated, horizontal and vertical market power. FERC, has adopted two screens for determining whether a party has horizontal market power: (i) a pivotal supplier screen and (ii) a market share screen. Applicants that pass both screens are presumed to not have significant market power. Applicants that fail one or both screens are presumed to have significant market power, but may rebut that presumption through mitigation efforts or by providing a Delivered Price Test analysis.

The pivotal supplier screen is used to determine whether a supplier is pivotal to the market. A supplier passes the pivotal supplier screen if its uncommitted capacity is less than the net uncommitted capacity in the market. In other words, this screen asks whether capacity from other entities, including imports, will be sufficient to meet wholesale demand in the market absent influence from the party being screened.

The market share screen calculates a supplier's share of uncommitted capacity in the wholesale market, and if the supplier's share of uncommitted capacity exceeds 20% of the uncommitted capacity of the entire market, the supplier fails the screen and is deemed to have market power.

Market-based rate sellers must also demonstrate that they do not have vertical market power. FERC has determined that when an applicant owns, operates or controls transmission facilities, a FERC-approved Open Access Transmission Tariff (OATT) adequately mitigates vertical market power. As such, a market-based rate applicant must either be bound by a FERC-approved OATT or receive waiver of the OATT requirement, and certify that it has and will not create barriers to entry into the relevant market in order to demonstrate a lack of vertical market power.

FERC also regulates wholesale market concentration by overseeing mergers and acquisitions of public utilities to ensure that the merger's effect on competition, rates, regulation and cross-subsidisation is consistent with the public interest. Section 203 of the FPA mandates that public utility mergers, consolidations, acquisitions, sales and leases be authorised by the Commission. Certain transactions are only subject to FERC authorisation if in excess of USD10 million; 16 U.S.C. § 824b.

Pursuant to the EPAct, when ensuring that a transaction is consistent with the public interest, FERC must also ensure that a proposed transaction will not cross-subsidise any non-utility or associated company, or that such cross-subsidisation is consistent with the public interest.

FERC relies on the Herfindahl-Hirschman Index (HHI) – a commonly accepted measure of market concentration – to determine whether the proposed transaction will increase market concentration to exceed the relevant market's threshold concentration levels. To determine when a merger and acquisition transaction will have an anti-competitive effect – or increase market concentration above acceptable levels – FERC uses the HHI and its Merger Policy Statement (MPS), issued in 1996, to analyse the transaction. Used across industries, the HHI is a widely accepted measure of market concentration, calculated by squaring the market share of each firm competing in a given market, and summing the results. The MPS articulates methods for further computing market concentration, identifies safe harbour concentration levels and outlines the methods to be undertaken if a transaction failed either screen. These guidelines can be found at www.ferc.gov/industries/electric/gen-info/mergers/rm96-6.pdf.

Energy industry mergers and acquisitions are also subject to review by the Department of Justice (DOJ) and the Federal Trade Commission (FTC). While FERC's review of mergers and acquisitions is a relatively straightforward public interest inquiry, the DOJ and FTC will typically follow their 2010 Horizontal Merger Guidelines (HMG) for a more complex analysis. DOJ and FTC authorisation may still be required upon FERC's approval of a transaction. These guidelines can be found at www.justice.gov/atr/public/guidelines/hmg-2010.pdf.

State utility commissions may also have jurisdiction to review public utility merger and acquisition transactions. However, instead of focusing on the wholesale market, their review focuses on the impact on retail rates and the public interest.

2.5 Agency Conducting Surveillance to Detect Anti-competitive Behaviour

The EPAct significantly augmented FERC's authority to prohibit market manipulation, anti-competitive behaviour, and fraud. FERC remains the primary authority overseeing competition in the wholesale electricity markets, while a variety of other federal agencies, such as FTC or DOJ, may also have jurisdiction over electricity market participants, particularly over antitrust violations and criminal behaviour, as part of their generalised authority to regulate anti-competitive behaviour across a variety of market sectors in the USA.

In the EPAct, Congress enhanced and added sections to the FPA, NGA and NGPA, which prohibit manipulative or deceptive practices and provided for maximum civil penalties of USD1 million per day, per violation of rules, regulations and orders issued under those acts. It also expanded FERC's authority with respect to anti-competitive behaviour by expressly prohibiting fraudulent or manipulative acts by "any entity" in the sale or purchase of electric energy or sale or purchase of transmission services – not merely entities providing service under FERC-approved market-based rate authority; see 16 U.S.C. § 824v. The EPAct also expanded the scope of criminal provisions provided in the FPA and NGA by increasing the maximum fines and imprisonment sentences when FERC refers a case to DOJ to pursue a criminal prosecution.

FERC implemented its authority under the EPAct by promulgating the Anti-Manipulation Rule in Order No 670 in 2006. The Anti-Manipulation Rule broadly defines market manipulation to include conduct such as: (i) using or employing any device, scheme or artifice to defraud; (ii) making untrue statements or omitting to state material facts; or (iii) engaging in any act, practice or course of business that would operate as fraud or deceit upon another entity – see 16 U.S.C. § 824v.

For market surveillance and enforcement, FERC has an Office of Enforcement (OE), which is comprised of scientists, engineers, attorneys, auditors, financial analysts and energy analysts. The OE has four divisions: the Division of Investigations; the Division of Audits and Accounting; the Division of Energy Market Oversight; and the Division of Analytics and Surveillance. Each division oversees a variety of functions, including ensuring compliance from market participants, initiating and executing investigations, providing warning of vulnerable market conditions, maintaining an Enforcement Hotline to informally resolve disputes, and advising the Commission on enforcement and compliance issues.

Further, ISOs and RTOs have a significant role in ensuring competitive wholesale electricity markets by employing market monitors to detect market manipulation. Each ISO/RTO has approved of Market Monitoring Plans, which implement a variety of activities designed to assess and improve wholesale electricity market competition. Similar to the functions of FERC's OE, RTO/ISO monitoring system functions include monitoring and ensuring compliance with market rules and procedures; gathering data; evaluating and reporting on market performance; proposing rule changes to improve market operation and performance; and, in some cases, employing mitigation measures and sanctions where authorised. Strengthening the role of these market monitors, under 18 C.F.R. § 35.41(b), market participants must provide accurate information, and must not submit false or misleading information or omit material information to market monitors.

For additional guidance on FERC's Anti-Manipulation Rule, see FERC Order No 670: http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=10932497.

3. Climate Change Laws and Alternative Energy

3.1 Principal Climate Change Laws and/or Policies

While the USA lacks a unified comprehensive federal approach to climate change, a number of federal and state laws and programmes are directed at limiting carbon emissions and advancing clean energy deployment. Holistic, market-based approaches to address climate change at the federal level have been debated for decades, but have not been adopted.

In the USA, Congress has the authority to address climate change through legislation and appropriation of funds, while the executive branch implements existing law through regulation and development of programmes. The primary federal laws regulating aspects of climate change and the power industry are the Clean Air Act (42 U.S.C. § 7401), the EPAct, the Consolidated Appropriations Act of 2016 and the Energy Independence and Security Act (42 U.S.C. § 152).

The CAA was enacted by Congress to protect the public health and welfare from a number of common air pollutants that come from a variety of pollution sources, such as industrial manufacturing, vehicles and electricity consumption. The CAA requires the Environmental Protection Agency (EPA) to implement rules and regulations to reduce the emission of such air pollutants, including carbon dioxide and methane. The EPAct regulates energy production in the USA, including renewable energy, energy efficiency, nuclear energy and security matters, oil and gas, and electricity. Significantly, the EPAct provides tax incentives and loan guarantees on infrastructure development for particular energy sources. The Consolidated Appropriations Act of 2016 retroactively reinstated and extended several renewable energy tax incentives for certain renewable sources, including the Production Tax Credit (PTC) and Investment Tax Credit (ITC). The Energy Independence and Security Act of 2007 was enacted with the goal of improving vehicle fuel economy and reducing US petroleum dependence by increasing renewable energy fuel sources. Among other things, the Energy Independence and Security Act: provides for funding research in renewable energy and carbon capture technologies; implements a biomass fuel standard; and mandates an increase in energy efficiency of new buildings, products and vehicles.

In the absence of a comprehensive federal climate change policy, a number of individual states have enacted legislation aimed at curbing greenhouse gas emissions and advancing clean energy deployment. Currently, 29 states, plus the District of Columbia, have adopted legislation with the goal of addressing climate change. While each state takes a different approach, many have generally taken a market-based or performance-standard approach. Current state legislation includes greenhouse gas emission targets, carbon pricing such as cap and trade policies, electricity portfolio standards, energy efficiency and decoupling policies, and transportation policies such as low-carbon fuel standards. Some states have grouped together in co-operative agreements, such as the Regional Greenhouse Gas Initiative (RGGI), wherein carbon emissions from fossil power plants 25 MW or larger are capped and traded in regional carbon allowance markets.

In addition to state and federal regulations affecting climate change, the USA has signed a number of international agreements that seek to address climate change. The latest in a series of international agreements on climate change, within the United Nations Framework Convention on Climate Change, is the Paris Agreement of 2015 (Paris Agreement). Pursuant to the Paris Agreement, the USA set targets to reduce greenhouse gas emissions to 17% below 2005 greenhouse gas levels by 2020, and 28% below 2005 levels by 2025. However, under the Trump administration, the USA is in the process of removing itself from the Paris Agreement.

3.2 Principal Laws and/or Policies Relating to the Early Retirement of Carbon-based Generation

In 2015, the Obama administration's EPA promulgated the CPP, which leveraged EPA's authority under the CAA to establish greenhouse gas emission reduction targets for each state and would have required each state to promulgate a state-specific plan to meet its target. However, in February 2016, a divided Supreme Court issued a rare stay on the implementation of the CPP and in June 2019, the EPA, under the Trump administration, replaced the CPP with the ACE. ACE provides states with new emission guidelines for developing performance standards on carbon emission reduction from existing coal-fired electric generators. While the CPP would have set emissions caps for each state, ACE takes a narrower approach by recommending efficiency improvements for individual power plants.

At the state level, various forms of legislation have been implemented to address carbon emissions and encourage early retirement of carbon-based generation. A number of states have entered into a RGGI, a market-based initiative to cap and reduce the power sector's carbon emissions. Based on the RGGI Model Rule, each participating state has a Budget Trading Program comprised of carbon emissions limits and allowance auctions. In RGGI states, fossil-fuel-fired electric generators that have a capacity of 25 MW or greater must hold allowances equal to that of their carbon emissions for a three-year period. Each year, the carbon emission allowance cap is reduced by 3% until 2020. Post-2020 cap levels have been established in RGGI's Model Rule Amendments. The proceeds from allowance auctions are invested in energy efficiency and renewable energy resources. While RGGI rules only apply to electric generating facilities, California has a similar programme that applies to a broader range of carbon-emitting facilities.

Another market-based state legislative approach to reducing carbon emissions is demand-side management (DSM) and/or non-wires alternatives (NWA) programmes. These programmes are designed to encourage electric utility consumers to modify their electricity consumption patterns. DSM can reduce peak demand and smooth load curves to decrease reliance on fossil-fuel-fired electric generators, while NWAs can defer or replace the need for traditional utility investments.

Additionally, RTOs and ISOs have rules regarding the retirement of generating facilities. Facilities necessary for reliability are not retired before the loss of electric energy can be replaced. There are several considerations that go into retiring a generation facility, including the age of the generating unit, capital and operating costs, market conditions, environmental restrictions and compliance costs. While FERC does not have authority over the retirement of most generation facilities, the Commission does mandate reliability standards under FPA § 215; see 16 U.S.C. § 824o. As such, RTOs and ISOs must assess the reliability of a retiring generating facility, and if applicable, can compensate units that are required to run past their preferred retirement date through reliability-must-run contracts.

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

The most significant federal incentives that encourage alternative energy development are the ITC and the PTC. As amended by the Consolidated Appropriations Act of 2015, the ITC provides a 30% tax credit for solar technologies, fuel cells and small wind turbines installed on residential and commercial properties. The ITC also provides a 10% tax credit for installed geothermal, microturbines, and combined heat and power systems. The PTC provides a tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person. For wind, geothermal, closed-loop biomass and solar systems not also claiming the ITC, the tax credit is USD0.023 per kWh, and for other eligible technologies is USD0.012 per kWh. These rates are administrated by the Internal Revenue Service, and are adjusted for inflation based on 1993's USD0.015 per kWh rate. The percentage tax credit available under the ITC is being reduced annually. While the PTC provides credits based on the amount of energy generated by qualifying facilities, the ITC credits are based on the upfront capital expenses of building and installing qualifying facilities. The PTC originally expired at the end of 2013, but was extended first by the Tax Increase Prevention Act of 2014, then by the Consolidated Appropriations Act of 2016. This allowed PTC-eligible facilities to claim the ITC tax credit in lieu of the PTC through the end of 2016, and the end of 2019 for wind facilities. Based on the technology, the largest tax credit available to developers after 2022 is 22%, and some technologies may no longer qualify for the ITC.

Another significant driver of renewable energy deployment are state-enacted Renewable Energy Portfolio Standards (RPS), variations of which have been implemented by 36 states plus the District of Columbia. An RPS is a state mandate requiring that a particular percentage of energy supply to retail customers be from renewable energy sources. The elements of an RPS programme vary by state as to which resources are eligible, how retail sales are measured, which types of utilities are subject to the mandate, whether there are cost caps to limit customer bill impact, and so on. Utilities subject to RPS mandates may either build qualifying renewable energy generation, purchase RECs, or pay alternative compliance payments and/or penalties. A growing number of states have recently enacted legislation creating ZEC programmes in which subsidies are provided to non-economic nuclear generation units. While structurally different depending on the state, ZEC programmes are generally closed markets in which ZECs are assigned to particular nuclear generating facilities to provide a stable income stream rather than to incentivise build-out of alternative energy resources.

Property-assessed clean energy (PACE) programmes are another model for innovative renewable energy financing. PACE programmes are created by cities or counties that designate a financing district, whereby property owners may voluntarily sign up for financing to install energy projects or make renewable energy improvements on their property. PACE financing allows property owners to make improvements without large upfront expenses. Property owners gradually repay improvement or installation costs over a set period of time, which are secured by the property itself and paid as an addition to the property owner's tax bills. Repercussions for non-payment are the same as those for failure to pay property taxes, and any subsequent owner to the land must be willing to fulfill the obligations of the property owner upon sale or transfer of the land.

See links below:

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

- https://puc.vermont.gov/electric/renewable-energy-standard.
- www.energy.ca.gov/programs-and-topics/programs/renewables-portfolio-standard.
- www.energy.gov/eere/slsc/property-assessed-clean-energy-programs.

4. Generation

4.1 Principal Laws Governing the Construction and Operation of Generation Facilities

The system of laws applicable to the construction and operation of generation facilities varies depending on the type of facility and its location. For the purposes of this discussion, distinction is drawn between offshore facilities and onshore facilities.

Onshore Facilities

State law will be the primary authority for the construction and operation of onshore generation facilities. Applicable laws generally take the form of (i) public utility law regulatory authorities, (ii) local/state permitting laws, and (iii) state environmental review laws.

In the first category, some states require that electric generating facilities obtain a Certificate of Public Convenience and Necessity (CPCN) or similar approval for generating facilities prior to construction and operation under the state's public utility laws. In the second category, local permitting may be required from the municipality where a facility will be sited in the form of a special use permit or similar approval under local zoning laws. In some states, permitting is governed by a centralised ('one-stop') siting board that may supersede some or all local permitting authorities. These are intended to streamline the permitting review process. In the third category, various state environmental review acts (or mini-NEPAs) apply, which generally resemble the federal NEPA. If a federal permit is involved and the project may result in discharge into waters of the USA, a Clean Water Act (CWA) Section 401 Water Quality Certification will be necessary.

Projects may also implicate federal authority. Specifically, where onshore projects involve federal lands, authorisation from the United States Department of Interior (DOI), Bureau of Land Management (BLM) or United States Forest Service may be required. Depending on potential impacts, involvement by various consulting agencies may be necessary under the Endangered Species Act, Migratory Bird Treaty Act, Bald and Golden Eagle Protection Act, and the Clean Water Act. Where federal action is involved, environmental review under NEPA will also be necessary. See www.blm.gov/programs/energy-and-minerals/renewable-energy and https://ceq.doe.gov/.

Offshore Facilities

Offshore generation facilities are routinely being proposed in the offshore areas of coastal states throughout the country. The Block Island Wind Farm – the country's first offshore wind farm – began operating off Rhode Island in 2016. The applicable laws for offshore facilities can be divided based on whether they are proposed for federal waters or state waters. Pursuant to the Submerged Lands Act of 1953, 43 U.S.C. Section 1301 et seq, states regulate coastal waters in the areas within three miles from shore. Federal regulatory authority is applied beyond that point to the limits of the USA's jurisdiction. Section 388 of the EPAct gave the U.S. Secretary of the Interior authority over offshore renewable energy facilities (including all energy resources other than oil and gas and minerals) in federal waters. In general, the DOI, Bureau of Ocean Energy Management (BOEM) issues leases, easements and rights of way for renewable energy development in federal waters pursuant to its regulations. Projects also typically require approval from the United States Army Corps of Engineers under Section 10 of the Rivers and Harbors Act (RHA) (obstructions to navigation in 'navigable waters') and Section 404 of the CWA (discharge of dredged or fill material). As with onshore facilities, offshore federal actions that may affect the environment require compliance with NEPA. In some cases, federal agencies have prepared programmatic environmental impact statements that are intended to streamline the environmental review process.

For offshore facilities within state jurisdiction, construction and operation of renewable generation projects will be governed by applicable state laws, including a state's 'mini NEPA', which generally provides for review, analysis and sometimes mitigation of environmental impacts associated with government action. State laws may also provide for the necessary easement, lease or other right to use state-owned land underwater. On the federal side, such projects require federal RHA Section 10/CWA Section 404 permitting (due to installation of facilities in navigable waters), which will also trigger compliance with NEPA. Finally, a CWA Section 401 State Water Quality Certificate will be needed for projects that require RHA Section 10/CWA Section 404 permits.

For federal projects requiring an environmental impact statement under NEPA, several recent federal streamlining provisions may apply. Executive Order 13807 creates a framework for 'One Federal Decision' and sets an average time frame of not more than two years for an EIS process. DOI Secretarial Order 3355, issued in response to Executive Order 13807, sets a page limit of 150 pages (300 for complex projects) and a one-year timeline for EISs. Both orders are broadly applicable to "infrastructure projects," which includes renewable energy.

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

As noted above, local, state and federal approvals may be required to construct and operate electric generation facilities. In many states, the applicant will need a CPCN or its equivalent from the state utility commission. As part of the CPCN proceeding, or as a separate process, an applicant will likely be subject to review by a multitude of state agencies and authorities, including the relevant counties and municipalities, drainage districts, state natural and environmental agencies, transportation authorities and cultural heritage preservation offices. The approval process will vary by state. The CPCN may include authority to exercise eminent domain for the purposes of the project. As noted above, in some states, a centralised 'one-stop' siting board is in place that is intended to streamline the siting approval process. Some projects may include regulatory approvals on the federal side where sited on federal lands or where federal programmes are triggered, such as CWA Section 404 (for discharges of dredged or fill material).

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

State, local and federal agency approval of generation facilities is contingent upon the terms and conditions as determined by the applicable agencies in the review process. As discussed previously, a company seeking a generation facility permit must undergo review by numerous authorities, which may include local, state and federal agencies/authorities. During such review, the applicable authorities often condition their approvals upon certain modifications or considerations intended to bring the proposed project into compliance with the relevant permitting standards, or otherwise reduce impacts that are of concern to the regulators.

4.4 Proponent's Eminent Domain, Condemnation or Expropriation Rights

A CPCN issued by a state public utility commission will often include eminent domain rights to the facility developer under terms and conditions specific to that state and its relevant laws. To act on their eminent domain authority, the developer must provide the landowner with just compensation based on the fair market value of the property being condemned on the date that the eminent domain is exercised. Typically, a court will determine the just compensation value of the condemned property

4.5 Requirements for Decommissioning

Decommissioning is often included as part of the terms and conditions of approval for generation facilities. The specifics of such requirements and how they are implemented are highly dependent on the local, state or federal authorities involved, and their unique practices. Permitting authorities may require formal decommissioning plans and financial security. In some cases, decommissioning requirements are applied based on discretionary approval conditions, while in other cases, specific legal requirements for decommissioning may be derived from applicable laws or regulations.

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 of Transmission Facilities

The US transmission system is comprised of facilities that are privately, publicly, federally or co-operatively owned. While individual states have primary authority over siting and construction of electric transmission lines and their associated facilities, federal authorities are involved in circumstances where a project is located on federal lands, spans multiple states or in certain designated areas. The EPAct enhanced co-ordination and communication among federal agencies with authority to site electric transmission facilities by, among other things, directing the DOE to co-ordinate all federal authorisations and related environmental reviews needed for siting interstate electric transmission projects; see EPAct 2005 § 1221(a), which added § 216(h) to the FPA, codified at 16 U.S. Code § 824p. DOE has authority to identify certain National Interest Electric Transmission Corridors, within which FERC has authority in certain circumstances to grant permits for transmission facility applications. FERC may also grant transmission facility permits when it finds that a state does not have authority to do so, the state commission withholds approval for more than a year after filing, or the facilities to be authorised will provide electric energy transmission in interstate commerce. FERC may grant a permit upon finding that the proposed construction is consistent with the public interest, will reduce congestion, is sound with the national energy policy or will maximise transmission capabilities of existing facilities.

For more information, see www.energy.gov/oe/services/electricity-policy-coordination-and-implementation/transmission-planning/coordination.

Under the FPA, the Secretary of the DOE has emergency authority to require temporary connections of generation, delivery or transmission electricity facilities that will best meet the emergency and serve the public interest; see 16 U.S.C. § 824a(c).

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

Both state and federal certifications and approvals are generally required to construct and operate electric transmission facilities. Some states may have a pre-filing consultation requirement designed to co-ordinate the review process across multiple agencies. Ultimately, the applicant will generally need to obtain a CPCN, or an equivalent certificate, from the state utility commission. As part of the CPCN proceeding, or as a separate process, an applicant will likely be subject to review by a multitude of state agencies and authorities, including the relevant counties and municipalities, drainage districts, state natural resource and environmental agencies, transportation authorities and cultural heritage preservation offices. These approval processes will vary by state. The CPCN may include the authority to exercise eminent domain for the purpose of building transmission lines.

In addition to state permits and authorisations, an applicant will likely need to obtain approval from several federal agencies, including the U.S. Army Corps of Engineers, the Federal Aviation Administration, the U.S. Fish and Wildlife Service, the Department of Agriculture, the Department of Commerce, the Department of Defense, the DOE, the EPA, the Council on Environmental Quality, the Advisory Council on Historic Preservation, the DOI and FERC. Eight of these federal agencies entered into a Memorandum of Understanding (MOU) in October 2009 to improve coordination among project applicants, federal agencies, and states and tribes involved in the siting and permitting process. The MOU designates a 'lead agency' as a single point of contact, which will coordinate all federal reviews necessary to the approval of the development and siting of the proposed facilities. See www.energy.gov.

When a company's permit application is subject to review by FERC, the company must meet with the Commission's Director of Energy projects to initiate the pre-filing review process. Upon approval from the Director, the Commission will issue a notice of the pre-filing process and the company must implement a Public Participation Plan to identify how it intends to communicate with stakeholders and disseminate information to the public. During this pre-filing stage, Commission staff will assist the company in preparing their complete application by conducting site visits, facilitating the identification and resolution of issues, and initiating environmental review of the proposed project. Once the company files a complete application, the Commission will review comments and recommendations from involved entities and individuals, hold public meetings and technical conferences, and clarify project-related issues. The Commission is required to act upon an application within one year of the filing date. In addition, FERC will issue a Notice of Intent (NOI) to prepare an environmental assessment (EA) or environmental impact statement (EIS). The NOI is sent to federal agencies, state and local agencies, and any entity or individual that may be affected by the transmission facilities, seeking comments from interested parties. After the comment period, FERC will prepare an EA or EIS to outline its findings and recommendations. FERC will address the comments in the EA or EIS, or in the final order granting or denying the application. The extent of the federal review process will depend on a number of factors, including the size and location of the project and the degree of coordination between the federal agencies and the applicant.

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

State, local and federal agency approval of transmission facilities is contingent upon the terms and conditions as determined by the applicable agencies in the review process. As discussed previously, a company seeking a transmission facilities permit must undergo review by numerous authorities, both state and federal. During such review, the applicable authority will make comments and recommendations and will condition their approval upon certain modifications or considerations that will bring the proposed project into compliance with the relevant safety, environmental, engineering and zoning standards.

5.1.4 Proponent's Eminent Domain, Condemnation or Expropriation Rights

A CPCN (or its equivalent) issued by a state public utility commission will often include eminent domain rights to the transmission facility developer under terms and conditions specific to that state. To act on their eminent domain authority, the developer must provide the landowner with just compensation based on the fair market value of the property being condemned on the date that the eminent domain is exercised. Typically, a court will determine the just compensation value of the condemned property.

On the federal level, if a facility project is granted a permit by FERC or the DOE, the transmission facility developer will have eminent domain authority; see 16 U.S.C. § 824p. The eminent domain authority can only be used for the permitted facilities. In using eminent domain, the developer should provide the landowner with basic information concerning the eminent domain process. The developer should refer the landowner to the relevant state agency or state Attorney General and should explain to the landowner that they have the right to acquire the property, or property rights, by eminent domain under FPA § 216(e). If applicable state law limits a developer's eminent domain authority, the federal authority overseeing the eminent domain proceeding is equally constrained; see FERC Order No. 689, §§ 225 – 227. www.ferc.gov/whats-new/comm-meet/111606/C-2.pdf.

5.1.5 Transmission Service Monopoly Rights

Under federal law, transmission entities do not have monopoly rights to provide transmission service within a specific geographic area. While historically transmission lines were owned by private, vertically integrated entities, FERC required transmission services to be unbundled and provided pursuant to each utility's FERC-approved Open Access Transmission Tariff, which sets forth the terms and conditions of using the transmission system; see FERC Order Nos 888, 889, 890. In 2011, FERC Order No 1000 built upon Order 890 to increase transmission development by requiring public utility transmission providers to participate in a regional transmission planning process to generate regional transmission plans. It also required improved co-ordination between neighbouring transmission planning regions for the siting of new interregional transmission facilities.

While federal law does not provide for monopoly transmission rights, state law and utility commission regulation may provide for such rights under terms and conditions that will vary by state.

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

Pursuant to the FPA, FERC has exclusive jurisdiction over transmission of electric energy in interstate commerce, the sale of electric energy at wholesale in interstate commerce, and over all facilities for such transmission or sale of electric energy. This jurisdiction is conferred by Section 201 of the FPA, and the principal laws of such jurisdiction are encoded at 16 U.S.C. § 824, 824(d), and 824(e). Utilities providing transmission service subject to FERC's jurisdiction must receive and abide by an OATT, which unbundles transmission operations and services and sets forth rates for transmission and ancillary services. Transmission providers must publish service, rates and available capacity, as well as rules and standards related to their transmission services on the Open Access Same-Time Information System (OASIS). FERC has authority to review and ensure rates and terms of transmission service are just and reasonable and not unduly discriminatory of preferential.

5.2.2 Establishment of Transmission Charges and Terms of Service

FERC determines the rates, terms and conditions of service for transmission of electric energy in interstate commerce. As required by the FPA, FERC ensures that transmission rates are just and reasonable, and that public utilities are not unduly preferential or advantageous to any entity by charging different rates to similarly situated transmission customers.

Wholesale rates are set according to sections 205 and 206 of the FPA. A rate case can be initiated by a utility filing for a rate change, by complaint from another person or entity, or by FERC's own initiative. Upon hearing, FERC will determine whether the utility's proposed rate is just and reasonable or make appropriate modifications to the rate as necessary; see 16 U.S.C. § 824e. Section 205 of the FPA requires that utilities filing for a rate change give the Commission 60 days' notice prior to the proposed date that the modification take effect.

FERC's policy is to permit utilities to establish rates through formulas. FERC will generally approve of or formulate new rates that are based on the utility's cost of service to balance the interests of the utility and its customers. Under this approach, the aggregate costs – such as the reasonable return on investment – for providing each class of service are determined, and prices are set to recover those costs. FERC generally uses the following formula, derived from a 12-month test period, to determine cost of service: E+d+T+(V - D) R, where:

- E = operating expense – utilities are generally entitled to recover prudently incurred operating expenses that relate to the provision of wholesale service;
- d = depreciation expense – depreciation means the loss in service value not restored by current maintenance that is incurred in the course of service;
- T = taxes – certain tax expenses associated with cost of service revenues;
- V = gross value of property – facility cost plus including working capital;
- D = accrued depreciation – depreciation of assets;
- R = overall rate of return – sufficient to allow the utility to maintain financial integrity, attract additional capital and earn a return comparable to similarly situated companies.

If any party to a FERC hearing was aggrieved by or does not agree with the result of FERC's order on the hearing, that party may request that FERC rehear the case. The rehearing request must be submitted within 30 days from the original order, and the Commission does not have the authority to extend this deadline. If the Commission does not act on the request for rehearing within 30 days, the request is deemed denied. After FERC issues an order upon rehearing, the parties to the hearing have the right to petition the United States Court of Appeals for review of the order, typically to the United States Court of Appeals for the District of Columbia Circuit, or the jurisdiction in which the utility has its principle place of business.

FERC has authority to intake and resolve complaints by assigning the case to alternative dispute resolution, issuing an order on the merits based upon the pleadings or establishing a hearing before an Administrative Law Judge. The Commission's decision on whether to conduct a formal evidentiary hearing on issues raised in complaints is generally discretionary.

5.2.3 Open-access Transmission Service

Pursuant to a series of FERC Orders first promulgated in 1996, transmission services must be provided on a non-discriminatory and open-access basis.

Starting with the EPAct, which encouraged FERC to foster competition in wholesale energy markets, FERC issued three key orders to require open access to transmission facilities. Order No 888, issued in April 1996, required all public utilities that owned, controlled or operated facilities used for transmitting electric energy in interstate commerce to file OATTs. Order No 888 permitted public utilities and transmitting utilities to seek recovery of legitimate, prudent and verifiable stranded costs associated with providing such open access.

Order No 889 required all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to participate in an OASIS to provide actual and potential open access transmission customers with information that would enable them to obtain open access non-discriminatory service. Transmission providers must publish service, rates and available capacity, as well as rules and standards related to their transmission services on OASIS.

FERC Order No 890 was issued in February 2007 to strengthen the OATT, reduce opportunities for undue discrimination, facilitate the Commission's enforcement and increase overall transparency in transmission system planning and use.

Issued in July 2011, Order No 1000 amended Order 890 by requiring public utility transmission providers to participate in a regional transmission planning process that produces a regional transmission plan in order to improve coordination between neighbouring transmission planning regions.

6. Distribution

6.1 Regulation of Construction and Operation of Electricity Distribution Facilities

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

The distribution system is primarily governed and regulated at the state level. State law and state utility commission regulations govern the methods and standards by which prudent distribution system investments are recovered in a utility's rate base or through other appropriate mechanisms. Construction, siting, zoning and other land use considerations and approvals generally fall within the purview of relevant city, county, and municipal authorities, which significantly vary by state.

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

While the substantive and procedural regulatory process for constructing and operating distribution facilities varies by state, state utility commission regulations generally focus on compliance with reliability, operational and safety standards. While some state utility commissions have authority over the siting and approval of permits for construction of distribution infrastructure, most states require the involvement and/or approval of multiple agencies, beyond the state utility commission, to review environmental, cultural, historical, technical and economic impacts.

Public participation and input may be permitted in accordance with applicable state and local laws. Similar to the federal processes, state law may require a public hearing, and the overseeing state agency or state utility commission may solicit public comments on the proposed distribution facility. Most state utility commissions have an online public docketing portal wherein applications, notices, comments, petitions, rulings and orders are posted. Depending on the state and the type of distribution facility being proposed, a utility or developer may need to file advance notice of a proposed facility, which may be subject to public comment. Timing of distribution system approvals may depend on state-specific public notice and comment requirements, utility rate case schedules, local government involvement, and state policy and regulation.

Generally, FERC plays a limited role in distribution infrastructure development, only becoming involved to the extent there is a jurisdictional question regarding the facility's status as a distribution or transmission facility, or if the facility implicates a federal law under the purview of FERC's jurisdiction.

6.1.3 Terms and Conditions Imposed in Approvals to Construct and Operate

The terms and conditions of distribution facility approval vary based on state regulations and market structures. In vertically integrated states, a state utility commission typically requires the distribution facility applicant to demonstrate that a facility is necessary, prudent, in the public interest, and just and reasonable in light of current market conditions and state policy objectives. Approval may be conditioned upon compliance with certain safety, environmental, engineering and public interest standards.

6.1.4 Proponent's Eminent Domain, Condemnation or Expropriation Rights

The power of eminent domain, condemnation and expropriation is commonly granted to electric energy distribution facility applicants upon review and approval of their construction and operation application. However, depending on the applicable state laws governing eminent domain, the rights of the distribution facility applicant will vary.

A distribution facility or utility exercising its right of eminent domain must provide just compensation for the property being condemned. The fair market value of the property being taken, or just compensation, will vary by state and may be determined by a state court.

6.1.5 Distribution Service Monopoly Rights

In most states, utilities have geographically defined service territories, provided for by state legislation or regulation, within which the utility has monopoly rights to provide distribution service. Exceptions may exist in some states for competitive market participants depending on state law and regulation. The degree to which monopoly service rights exist, the extent of deregulation, the method by which such rights are modified and the opportunity for competitive market participants to compete within those service territories significantly varies by state.

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 authority over electric energy distribution is each state's utility commission, which typically has broad authority to ensure just and reasonable rates, terms and conditions of distribution service in accordance with state legislation, regulation and promulgated rules.

Phillips Lytle LLP

One Canalside
125 Main Street
Buffalo, New York 14203

Tel: 716-847-8400
Fax: 716-852-6100
Email: info@phillipslytle.com
Web: www.phillipslytle.com

6.2.2 Establishment of Distribution Charges and Terms of Service

FERC imposes a functional test for the case-by-case determination of whether a facility is providing interstate transmission service or local distribution service, but generally defers to states' interpretation and application of those factors in making its determination. State utility commissions have jurisdiction over rates and terms of service for retail distribution level utility service. Generally, the rate-making process is designed to balance the utility company's opportunity to earn a fair return on its investments and the customer's interest in receiving safe, reliable service at just and reasonable rates.

For utilities with rates that are regulated by a state utility commission, rates are generally set through regulatory proceedings following submittal of a request to increase base rates along with written supporting testimony and evidence. The state utility commission, along with interested parties that seek to intervene, may propound interrogatories and/or requests for information on the utility and vice versa. Generally, parties will brief their positions and the rate case may settle if a sufficient number of parties agree to a joint settlement, or the case may proceed to formal hearings. In most states, the utility rate case documents are posted on a public docketing database, unless they are confidential or protected pursuant to state regulations and state utility commission rules. The process, frequency, duration and time-frame for rate cases depend on the state in which the distribution facility is located and the utility tariffs that seek to be modified, but the process generally ranges from eight to 12 months and results in an order covering one to three years.

Most states operate under a cost of service regulatory model whereby the regulator determines the utility's revenue requirement that reflects the total amount that must be collected from customers in rates for the utility to recover its reasonable and necessary expenses, as well as earn a reasonable return on investment. The revenue requirement is generally derived through a formula that accounts for the utility's rate base, a fair rate of return, operating costs, depreciation expenses, taxes and other costs. The treatment of electricity supply, among other items, will vary depending on the degree to which states have restructured their electric market. While states may have different approaches to calculating a rate of return, the rate should be sufficient to maintain financial integrity of the utility, enable attraction of additional capital and be equal to that earned by other companies with comparable risk profiles. Depreciation rates are approved by state utility commissions upon review and consideration of depreciation studies, which are generally performed by depreciation consultants and supported with expert testimony in rate case proceedings. Some states have adopted alternative rate-making methodologies that are focused on incremental rate recovery, performance-based metrics and other adjustment mechanisms that vary by state.

Following issuance of a formal ruling or order on a utility's rate request, a utility or interested party may request a rehearing or reconsideration depending on state law and regulation. Once a final agency determination has been reached, and all administrative remedies have been exhausted, an entity may appeal the decision to the applicable state court for judicial review.

State utility commissions may have rules or regulations governing the process for filing complaints and/or challenging existing rates and terms and conditions of service. Such complaints and challenges may be directed to utility consumer protection bureaus that serve as mediators to efficiently resolve disputes. The substantive and procedural elements of this process will vary by state.