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The Full Cost of Electricity (FCe-)

The History and Evolution of the U.S. Electricity Industry

PART OF A SERIES OF WHITE PAPERS

TEXAS
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THE FULL COST OF ELECTRICITY is an interdisciplinary initiative of the Energy Institute of the University of Texas to identify and quantify the full-system cost of electric power generation and delivery – from the power plant to the wall socket. The purpose is to inform public policy discourse with comprehensive, rigorous and impartial analysis.

The generation of electric power and the infrastructure that delivers it is in the midst of dramatic and rapid change. Since 2000, declining renewable energy costs, stringent emissions standards, low-priced natural gas (post-2008), competitive electricity markets, and a host of technological innovations promise to forever change the landscape of an industry that has remained static for decades. Heightened awareness of newfound options available to consumers has injected yet another element to the policy debate surrounding these transformative changes, moving it beyond utility boardrooms and legislative hearing rooms to everyday living rooms.

The Full Cost of Electricity (FCe-) study employs a holistic approach to thoroughly examine the key factors affecting the *total direct and indirect costs* of generating and delivering electricity. As an interdisciplinary project, the FCe- synthesizes the expert analysis and different perspectives of faculty across the UT Austin campus, from engineering, economics, law, and policy. In addition to producing authoritative white papers that provide comprehensive assessment and analysis of various electric power system options, the study team developed online calculators that allow policymakers and other stakeholders, including the public, to estimate the cost implications of potential policy actions. A framework of the research initiative, and a list of research participants and project sponsors are also available on the Energy Institute website: energy.utexas.edu

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This paper is one in a series of Full Cost of Electricity white papers that examine particular aspects of the electricity system.

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The History and Evolution of the U.S. Electricity Industry

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EXECUTIVE SUMMARY

Universally available, reliable, and affordable electricity is associated with a nation's improvements in quality of life for its citizens, increased productivity, and competitive advantage. The structure of the electricity industry – of generation, delivery, and use of electricity – over the past century has evolved significantly. For decades, scale economies associated with large centralized generation technologies encouraged vertical integration and drove down the cost of electricity, fostered universal access, and provided for reliable electric service delivered by a single utility in a given region. Starting in the 1970s, higher fuel prices, environmental concerns, technological innovations and a desire for more economic efficiency led to the rethinking of this vertically-integrated, regional monopoly model.

Following the restructuring of the telecommunications industry and the natural gas industry, policy makers began to rethink the notion that power generation and sales are (or should be) a natural monopoly. In the 1980s policy makers chose to break up the telephone monopoly in the U.S., unleashing competitive and technological forces that have transformed the communications sector. In the late 1970s and 1980s a series of government decisions deregulating wellhead prices and the pipeline industry unleashed powerful market forces in the natural gas industry, ultimately making both natural gas and gas-fired power much less expensive. The increased competition from merchant generators encouraged restructuring of the electric power industry in many states, breaking down the vertical integration model.

During the same timeframe, innovations in finance were created that complemented these new technologies to help make them more cost competitive. An important example is the Power Purchase Agreement (PPA) for independent natural gas plant electricity production and, later, wind and solar plants. These agreements played a key role in financing non-utility owned generating assets by enabling their owners, known as independent power producers (IPPs), to raise investment capital, employ tax-exempt bond financing, and capture Federal tax credits, enabling IPPs to provide renewable power at attractive long-term fixed prices to utilities. By the mid-1990s, policy makers began to restructure the electricity system, seeking to take advantage of these same technological and competitive forces in order to promote innovation and reduce electricity costs.

At the same time, policymakers incentivized alternative technologies, such as wind power. Both the federal and state governments implemented environmental regulations, tax credits, and other support programs for renewables. Solar technology, initially much more expensive than wind, did not benefit from these policies until the late 2000s and early 2010s when some states instituted programs that specifically supported solar installations. For both wind and solar, foreign government support for manufacturing has also been critical (e.g., Denmark for wind in its early days, and China for solar PV more recently). These technologies also enabled some customers to start generating some of their own electricity, competing with their local utility or competitive generators, and threatening the traditional utility business model as well as the competitive market structure as they exist today.

Several technologies will combine to drive changes in the electric industry: increasingly cost competitive wind and solar PV, inexpensive natural gas combined with flexible and efficient combined cycle gas plants, and electricity energy storage and demand response systems with progressively lower costs. These and other technological changes will continue to encourage the industry to adopt new technology and business models, policy makers to consider alternative regulatory and electricity market structures, and electricity customers to pursue self-generation that competes with traditional utilities in ways that may further de-stabilize the existing order. ■

1 | INTRODUCTION

The basic functions of the electric power industry, as historically structured, are electricity generation (production), transmission and distribution (T&D) to deliver electricity from the point of generation to the point of consumption, and customer relationship management.

There are various regulatory approaches for arranging the relationship between electricity generation and end-use consumption. Historically, a vertically integrated utility in the U.S. was an investor-owned utility (IOU) and was regulated by an independent public entity typically known as a public utility commission (PUC) or public service commission (PSC) (see Figure 3, Model 1). State-owned utilities in most of the world tended to also be vertically integrated (see Figure 4, Model 5). The customer relationship, where it mattered (primarily the U.S.) consisted primarily of monthly billing, outage management and advertising to encourage either conservation or consumption growth, depending on the situation.

The goal of this document is to summarize the history of the U.S. electric power industry, describe how the utility business model came to fruition, and introduce the more recent drivers for changing that model. In many cases, the historical business structures and regulatory models have become challenged across the United States over the past few decades. Thus, with the background in this document, the reader can contextualize the drivers for recent and future changes within the electricity industry.

The rest of this document is organized as follows. Section 2 provides a history of the interplay between technology, finance, and regulation that formed the traditional regulated electric utility business model. Section 3 describes the major ownership (for-profit and non-profit), management, and regulatory models of modern electricity grids. Section 4 provides some future perspectives and technological drivers for continued regulatory and consumer changes before Section 5 provides a brief conclusion. ■

2 | FORMATION OF THE ELECTRIC UTILITY MODEL

OVERVIEW

The dominant model for delivering electricity to consumers was, and remains, large-scale, central generation facilities, and transmission and distribution networks at regulated prices (rates) (see Figure 3, Model 1). The traditional utility business model formed within the interplay of technology, finance, and regulation.

The business structure was created in the early 20th century as the industry pioneers like Samuel Insull realized that ***technology*** allowed for power plants to become larger (especially, using steam turbines) and to reach ***economies of scale*** that reduced the unit cost of power. Insull and other early electricity providers also realized that they could make money selling electricity to a more diverse set of customers throughout the day, rather than simply serving evening electricity demand (or "load"), which was the basis of the early electric systems. This realization led them to acquire more customers and to grow their service territories. These large power plants and networks necessitated ***financing mechanisms***, via holding companies with multiple investors or later, access to low-cost financing via the debt markets. These progressively more advanced methods of equity and debt financing enabled new infrastructure (power plants, transmission and distribution lines) to be built and paid for over time, but without all the risk falling on a single company or investor. ***Regulation*** was considered necessary to allow electric companies to operate as monopolies to avoid waste of capital resources in duplicate infrastructure, create a regulatory compact that included an obligation to serve within the monopoly service area, stabilize the cost of capital by reducing risk, and provide affordable electricity service. To protect customers from monopolistic prices, electricity rates started to be regulated first by municipal, then by state governments. Federal regulation became relevant when grids grew larger across state borders, thus generating interstate commerce.

The traditional vertically integrated system persisted into the 1990s, when the federal government and some states decided to restructure the electricity industry, breaking vertically integrated utilities into generation and wires businesses, and introducing competition in the generation sector. In the late 1980s, Chile and the UK initiated a restructuring of their traditional vertically integrated electric power monopolies to introduce competition primarily at the wholesale or "bulk power" level where generators compete in a market. These efforts provided some guidance for restructuring in the U.S. Changes to the traditional model were also precipitated by a series of laws passed by the Congress between 1978 and 1992, which laid the foundation for the introduction of independent power producers (IPPs) into the market, the shift to market pricing of power, and the unbundling of electricity delivery from electricity sales. Today, the roles of both federal and state regulators in states with restructured electricity markets are more complex as they attempt to maintain grid reliability by managing robust and maturing competitive markets with more participants, increased integration of new sources of electricity generation, and increased demand-side participation into the system.

TECHNOLOGY

The modern electric utility industry in America began with Thomas Edison's invention of the first practical light bulb in 1879. Within three years, Edison built the first "centralized" fossil fuel driven power plant at Pearl Street in New York City's financial district. Adoption quickly followed in homes, factories, and in transportation to maximize the usefulness of this energy source. Entrepreneurs recognized the potential for electricity to revolutionize every aspect of American life from the home to the factory, and they engaged government first at the local or municipal level to facilitate the construction of infrastructure.

Thomas Edison's original system design was based upon direct current (dc) and low voltages. Because of high dissipative power losses in wires, this limited the transmission distance from power plant to end use point for electric power, which in turn restricted interactions with government to the local level. The power was generated and consumed within only a few miles. However, technological advances soon extended the scale and reach of electricity generation, and simultaneously necessitated an expanded role for government.

The most significant technological advance was alternating current (ac) electricity. By 1896, in the famous "power wars", Westinghouse Electric (with the help from inventor Nikola Tesla) had introduced ac electricity, expanding the reach of power plants to dozens of miles (1000s of miles today) from the point of electric load. The shift from dc to ac technology made larger scale (e.g., larger power plants) systems possible. This shift was largely due to the fact that ac permitted the power to be transmitted at high voltage and low current, substantially reducing power losses relative to dc systems. In turn, the use of ac transmission permitted the *exploitation of the economies of scale* for power plants, reducing the unit cost of electricity, and making electricity progressively more affordable and available to ever more customers.

After this dc-to-ac transition, for decades the technology evolved along the lines of what has become the traditional electricity utility model: large scale centralized generation sending ac electricity over transmission and distribution lines to consumers. While the vast majority of transmission is high voltage ac, modern high voltage dc transmission lines have been selectively used primarily for point-to-point long distance connections to transfer large amounts of power with enhanced stability over an ac connection.

For the past century, scale economies associated with large centralized generation technologies encouraged vertical integration and drove down the cost of electricity, fostered universal access, and provided for reliable electric service delivered by a single utility in a given region.

The initial loads on these early power systems were mostly lighting, followed closely by electric motors, loads that were well suited for ac power. However, over the past few decades the explosion in the number of computers, microprocessors, and telecommunications systems provided loads that are inherently suited to dc. These devices require better power quality than lights and motors, while the rectifiers (that convert ac to dc) in the systems often produce power quality challenges. At the same time, distributed energy resources such as solar photovoltaic (PV) panels and batteries provide energy sources that are also inherently dc. In order to avoid losing the competition to serve this new kind of load, utilities may need to adapt by offering new energy delivery models, such as dc microgrid overlays on top of their existing ac distribution systems. Legislatures and utility regulators play an important, if not essential, role in redefining the regulatory environment that defines the incentives and structure for utility business models. The traditional vertically integrated structures that were appropriate for the 20th century may inhibit desired incentives, investments, or innovation of utilities.

FINANCING

During the very early years of distributing electricity, grids were local, and used small neighborhood power plants (combustion engines) to generate power. The amount of capital required was relatively modest and then-available financing resources were adequate. With the transition to large ac systems (e.g., 100+ MW thermal and hydroelectric power plants), however, it was obvious that larger-scale financing was required. Electric companies could issue bonds to build these plants, but the risk was becoming too great for the investors that participated in the debt market of the era.

To reduce both risk and financing costs, the concept of a ***holding company*** was developed to blend the bonds from existing as well as new power plants and to also provide cash flow from one of the associated firms to finance further growth in another one of the held firms. Samuel Insull, a franchisee of Thomas Edison, recognized the potential for economies of scale and the role for the natural monopoly in electricity. He invested heavily in centralized power plants. By 1907, Insull had acquired twenty companies and formed Commonwealth Edison, beginning a cycle of centralization in the electric utility industry [1].

Despite growing state regulation (discussed in the next section), consolidation and private expansion continued in the electric sector through the 1910s and 20s, often using the financial innovation of holding companies. Applying this tool, Samuel Insull controlled businesses in 32 states with more than $500 million in assets in 1930. By 1932, eight holding companies controlled three-fourths of the IOUs, with most of their operations exempt from state regulation due to the crossing of state lines [2].

Financial product innovations served to fuel the growth of the U.S. power system with minimal problems until the last quarter of the 20th century, when fuel prices increased and some utilities began losing money when regulators refused to allow them to charge rates that reflected these cost increases. Unprofitable operations, in turn, inhibited some utilities' ability to raise financing for new plants. Moreover, the scale of the new plants could sometimes be so large relative to the size of the utilities' assets or revenue that some smaller utilities could not afford to own and build a new large power plant without partners; meanwhile, regulators would not allow smaller utilities to take the risks associated with building such large facilities without historical precedent in their jurisdiction. This was particularly true with new nuclear construction and the reason why some nuclear power plants were owned by multiple companies in the 1970s and 80s.

Today, there is a corresponding struggle to finance large coal and nuclear power facilities (with capital costs of several billions of dollars each) in competitive wholesale markets. The vast majority of new generation capacity is relatively smaller natural gas, wind, and PV facilities (with capital costs of $100s of millions). Today, the ability to add new generation capacity in smaller sized increments can be attractive for utilities in an era of low load growth; it helps them to better manage cash flows, reduce capital demands and risk, and to simplify the project development, ownership, and operation structures.

REGULATION

In terms of the chronological development of electricity regulation, the electric power industry generally evolved from being unregulated, to being regulated first by municipalities, then states, and then the federal government. Today in the U.S., the states typically regulate the retail sale of electricity, while federal law authorizes the Federal Energy Regulatory Commission (FERC) to regulate wholesale markets that involve interstate commerce and interstate transmission of electricity.[1]

The first progressive reformers in New York and Wisconsin expanded regulation of the industry to the state level at around the same time Samuel Insull was consolidating electric companies into what would become Commonwealth Edison. In 1905, Wisconsin's Governor Robert LaFollete established a state-level railroad commission to regulate railroad rates, schedules, service, and operations. Two years later, the Wisconsin legislature extended regulation to the state's electric companies, and New York State regulated its electric industry in the same year. Following the Progressives' lead, 45 states had established government oversight of electric utilities by 1914 [3].

The Federal Power Commission & Federal Energy Regulatory Commission

Congress first established the Federal Power Commission (FPC) by the Federal Water Power Act in 1920 to license hydroelectric dams on navigable waters or lands owned by the Federal Government. It later designated that the commission be comprised of five members, serving staggered terms, with no more than three from the same political party. This structure

1 The ERCOT market in Texas does not include ac transmission of power across state lines, so it is mostly exempt from Federal Power Act regulation.

remains in place today within the Federal Energy Regulatory Commission (FERC), the subsequent federal agency that subsumed the FPC. Since the Federal Power Act of 1935, the FPC and now FERC has been charged with ensuring that wholesale power sales and transmission service be offered at rates that are "just and reasonable, and nondiscriminatory." During the early decades of the FPC, the commission's power to regulate interstate commerce in electricity and natural gas were further expanded or clarified.

After the Great Depression Progressive reformers began to warn of the dangers of monopolies combined with lax regulation, and to see electricity as an essential public good. Campaigning for President in 1932, Franklin Roosevelt (FDR) vowed to fight "the Ishmaels and Insulls, whose hand is against everyman's [4]." Subsequent New Deal reforms established new regulatory frameworks for the electric industry as well as programs designed to bring electricity to rural America.

Electrification was seen to be an important technology to combat poverty and improve the quality of Americans' lives. The formation of the Tennessee Valley Authority (TVA) in 1933 introduced public energy policy as a tool to fight rural poverty in America. By the 1930s, ninety-percent of urban households had electricity compared with only ten percent in rural areas. Private industry demonstrated little interest in serving rural America due to the high construction costs, low population density, and perceived lack of ability for customers (e.g., poor farmers) to pay for the electricity. In response, FDR followed TVA with an executive order establishing the Rural Electrification Administration in 1935 prior to Congress enacting the Rural Electrification Act (REA) in 1936. These federal actions stimulated the introduction of electric service in rural areas, substantially improving quality of life for Americans, and encouraging business to enter and drive further economic development.

By 1939, the REA had helped to establish 417 electric cooperatives in rural areas, serving 25% of rural households in America. At the time of FDR's death in 1945, an estimated 90% of rural farms were electrified [5]. Rural electrification in the period increased from 13% to 94% [6]. TVA then created the Electric Home and Farm Authority (EHFA) to increase the supply of electric ranges, refrigerators, and water heaters to rural areas and to provide low-cost financing for farmers to afford them. The REA and TVA made a significant contribution to the reduction in poverty in the U.S. In addition to rural co-ops, investor owned utilities have shown to be effective providing more than half of the electricity in the US.

The Public Utility Holding Company Act of 1935 (PUHCA) also had a lasting influence on the electric utility industry in America. Congress passed the PUHCA to facilitate the regulation of the electric utility sector by either confining their operations to a single state or limiting operations that cross state lines to a contiguous geographic service area, easing regulation. PUHCA also outlawed the highly leveraged and opaque multi-level pyramids of holding companies that contributed to the economic collapse during the Great Depression. Remaining interstate holding companies and most companies that delivered a substantial amount of electricity were forced to register with the new Securities and Exchange Commission (1935). Along with other public companies, these utility companies were now required to follow the more strict Securities and Exchange Commission (SEC) rules for financial reporting and to obtain approval to issue stock and bond securities [7]. ***In effect, PUHCA of 1935 established the framework for the traditional electric utility industry.***

National Electric Reform

The traditional regulated utility model, first formalized by the Public Utility Holding Company Act of 1935 and governed as a natural and technical monopoly, remained mostly unchanged until the energy shocks in the 1970s. The energy price spike following the 1973 Arab Oil Embargo set the expectation among utilities and regulators that energy prices would continue to increase in the decades to come. Utilities also expected continued growth of electricity demand driven by a growing population, the need to switch away from more expensive petroleum fuels for heating and power generation, and continued supply disruptions from oil-exporting Arab nations or more specifically from the Organization of Petroleum Exporting Countries (OPEC). As a result of these expectations and the belief that natural gas supplies were limited, utilities developed ambitious plans for power plants based on coal and large-scale nuclear technologies, which turned out to have construction costs much higher than historic averages [8]. Some of these utility plans were influenced by the Power plant and Industrial Fuel Use Act (PIFUA) of 1978 (repealed in 1987) that, among other fuel use restrictions, prevented the use of natural gas by regulated utilities in power plants (except where it was necessary to reduce air pollution associated with burning coal or oil). By restricting the use of natural gas for electricity generation by utilities, PIFUA stimulated a large build-out of coal power plants during the 1970's and 1980's. While these coal plants contribute a significant portion of the emissions of the entire power generation sector, many of them are now uneconomic and being retired given low natural gas prices from the surge in gas supplies from hydraulic fracturing techniques, efficient combined-cycle gas plants, declining costs of wind and solar generation, in addition to implemented or proposed environmental regulations.

The perception of future energy shortfalls also created an opportunity for smaller scale plants such as small hydropower sites, industrial co-generation, burning of municipal waste, and renewable resources such as geothermal energy, wood, wind, and solar. With the traditional utilities mainly focused on large-scale and capital-intensive projects, the development of these new smaller and/or renewable resources was contingent upon the purchase of their output by utilities at favorable terms. To encourage the development of these new resources and to diversify the domestic electric power base, Congress passed the Public Utility Regulatory Policies Act of 1978 (PURPA). Section 210 of this federal legislation created a new legal category of power plants known as qualifying facilities (QFs), with specific size and other characteristics, that enabled new market entrants such as non-utility generators, or NUGs (e.g., power producers that

BOX 1:

The Role of Natural Gas Industry Restructuring in Driving Changes in the Electric Power Industry

The Natural Gas Act of 1938 gave the FPC the power to regulate the sale and transportation of natural gas in interstate commerce. In 1940, amendments to the Natural Gas Act enabled the FPC to certify and regulate natural gas facilities, and the 1954 court ruling Phillips Petroleum Co. v. Wisconsin required the FPC to begin regulating natural gas wellhead prices. This action proved to be poorly conceived in that it eventually constrained gas exploration, and supply as well as technology innovation along the natural gas supply chain and by end-users. As part of the energy sector reforms in 1978, the Natural Gas Policy Act was passed along with PIFUA and PURPA that started the process of phasing out gas wellhead price regulation. Within a decade, rising market prices fostered new drilling and the development of new exploration and production techniques that led to significant new supplies and price declines.

Several orders by FERC in the 1980s and early 1990s, were designed to increase competition in the natural gas sector. The 1985 FERC Order No. 436 required that natural gas pipelines provide open access to transportation services, enabling gas consumers to negotiate prices directly with producers and contract separately for transportation. In 1992 FERC issued Order No. 636 (The Restructuring Rule) that mandated unbundling of sales services from transportation services, provided customers with a full choice of providers, and opened these markets to competition. In 2000, FERC Order No. 637 further addressed inefficiencies in the capacity release market. Together with PURPA and PIFUA, these changes in the natural gas industry fueled the emergence of the IPP sector, facilitating wholesale electricity competition.

There are many parallels between natural gas and electricity regulation. Both systems need to connect producers, via transmission and distribution infrastructure, to end-use consumers. The restructuring of the natural gas markets with the unbundling of services and open access to transmission provided a model for the subsequent restructuring of the electricity market.

were not utilities and did not own transmission lines) [9]. PURPA required local investor-owned utilities to purchase the output from QFs, at full avoided-cost (the cost utilities would incur if they were to generate the same amount themselves or purchase it from another source). Some states enacted laws and regulations specifying avoided-cost rates for power purchases from QFs. Initially, some states established avoided-cost rates that exceeded utilities' actual avoided-costs, until the Supreme Court struck down those laws in 1984.[2]

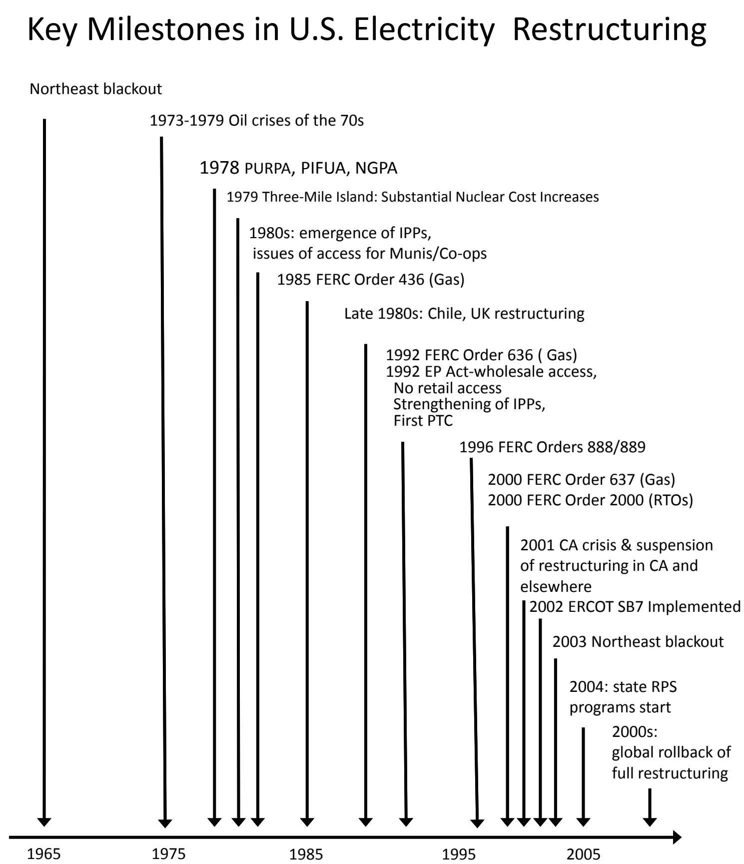
Congress responded to the 1970s' energy crises by reorganizing the FPC into to the Federal Energy Regulatory Commission (FERC) in 1978 to streamline regulations, encourage greater energy security, and contain the increases in energy costs. An important aspect of these efforts was to wean U.S. power generation from oil (particularly imported oil) to domestic sources of energy.

Subsequently, in the 1980s and 1990s FERC finalized orders that significantly restructured natural gas markets (see Box 1). These orders enabled merchant developers of electricity generation plants to bypass local natural gas distribution companies and reduce their fuel costs by buying natural gas in the wholesale market and connecting to transmission pipelines directly.

Wholesale electricity competition was further strengthened by the 1992 Energy Policy Act that authorized FERC to order "wheeling" (the transport of) of third party power over utility lines. This act also more broadly authorized new non-utility generation facilities to sell their electricity to utilities at market prices. Wholesale competition would not have been possible at the same pace and scale without the confluence of these laws and actions that allowed natural gas fired generation to become a key player from non-utility co-generation and CHP power plants. These non-utility generators sold their excess power to the utilities that could not legally burn natural gas in their own plants. Nowadays, these non-utility generators are commonly known as merchant

FIGURE 1:

Milestones in U.S. electricity restructuring



plants or independent power producers, or IPPs.

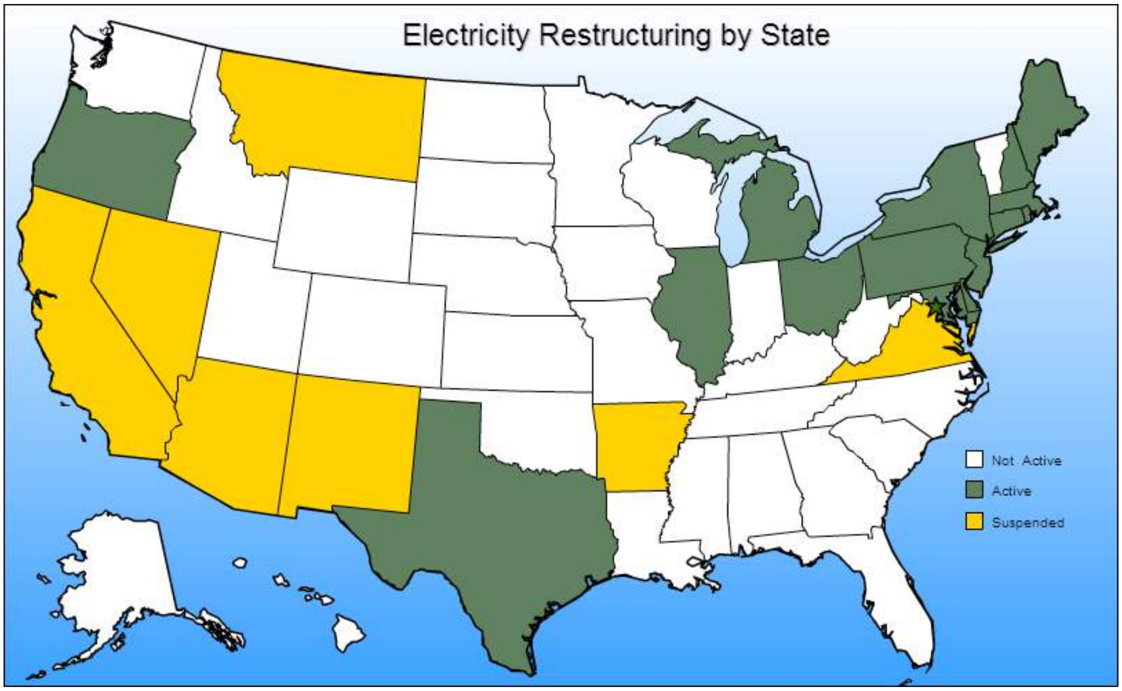
Using many of the concepts and lessons from the restructuring of the natural gas industry in the 1980s, FERC also pursued similar reforms in the electricity sector; Orders 888 and 889, issued on April 24, 1996, were particularly significant. These orders:

- Require transmission owners to offer nondiscriminatory, comparable transmission service to others seeking such services over its own facilities. This often is referred to as the "open access" rule;
- Ensure that potential suppliers of electricity have equal access to the market; and
- Encourage the creation of a separate Price Exchange to reveal market-clearing prices for electricity in the new competitive market [10].

2 Deregulation of the wellhead price of natural gas after 1978 rapidly increased gas supplies. Many of the QFs and NUGs built in the 1980s were gas-fired combined heat and power (CHP) facilities, sometimes also referred to as co-generation plants

FIGURE 2:

Electricity Restructuring by state (Source EIA [11]). Restructuring implies that a monopoly system of electric utilities has been replaced with competing sellers.



Additional reforms by FERC and Congress have continued to progress towards electricity market restructuring after 1996. FERC Order 2000 called for formation of regional transmission organizations (RTOs), an enhanced version of independent system operators (ISOs) with better regional control of transmission grids. In the wake of the California electricity crisis of 2000-01 the FERC has continued to work on the institutional design of wholesale electricity markets. In 2002, FERC proposed, but later withdrew in response to concerns raised by states and other stakeholders, rules for a Standard Market Design (SMD). The Energy Policy Act of 2005 (EPACT2005) gave FERC new authorities to police manipulative behavior in electricity markets. EPACT2005 also repealed the Public Utility Holding Company Act of 1935, formally bringing to a close the original federal regulatory structure established by New Deal-era legislation. While FERC was opening wholesale power markets to competition in the late 1990s and early 2000s, some state Public Utility Commissions became more active in pushing market restructuring and/or alternative technologies and demand-side participation while others mostly maintained the traditional utility structure.

The major milestones in the U.S. restructuring process are presented in Figure 1.

Figure 2 presents a summary of the situation at state level for actions initiated.

3 | ELECTRICITY INDUSTRY ORGANIZATIONAL STRUCTURES

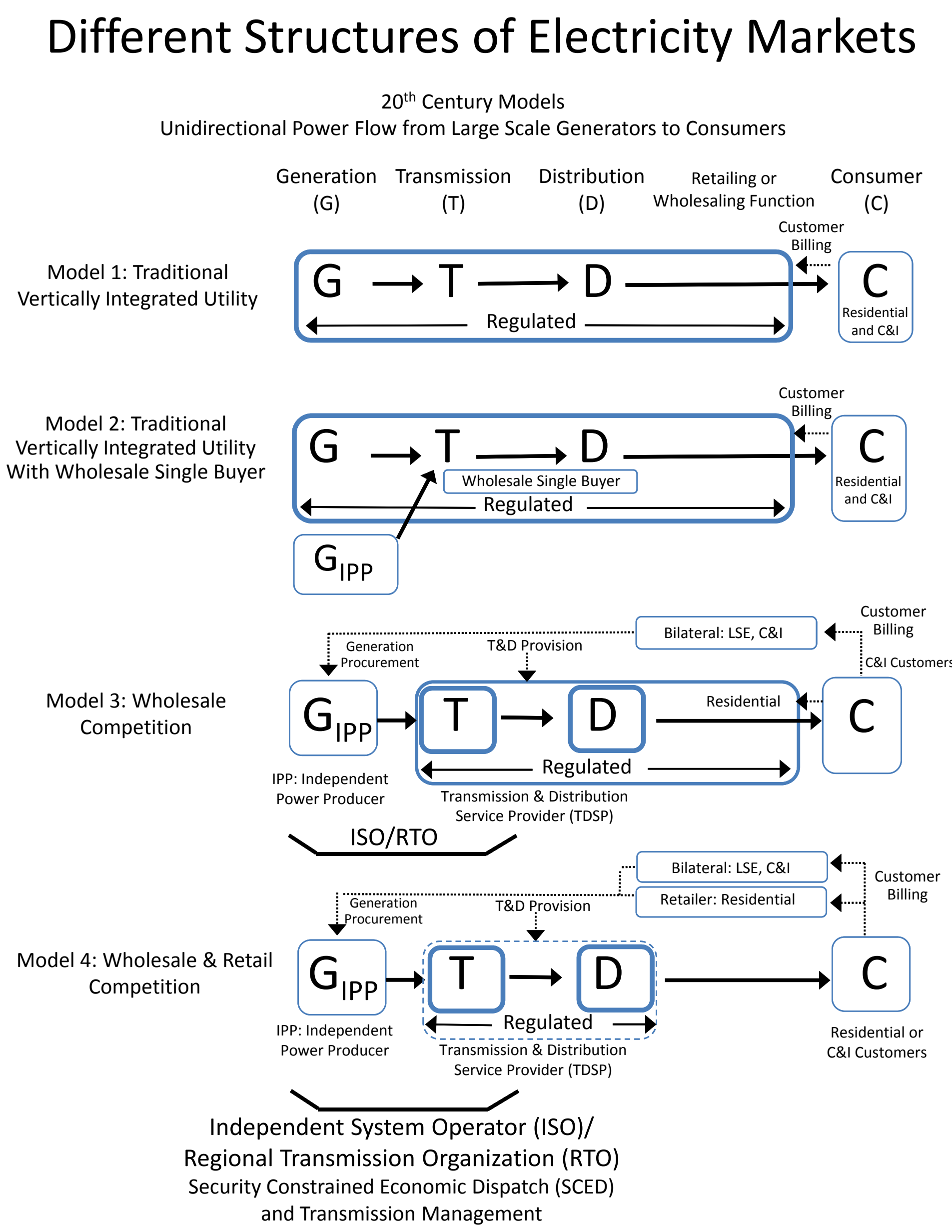
Now that we have provided an overview of the historical interplay of technology, finance, and regulation that has shaped the electricity industry, we now represent the various electric grid regulatory structures via a framework of six simplified models.

INVESTOR-OWNED UTILITIES (FOR PROFIT OWNERSHIP)

There are many ways to categorize the organization of electric utilities. From the point of view of investor owned utilities (IOUs) there are four

FIGURE 3:

Typical Investor Owned Utility (IOU) Electricity Market Structures



main ways of structuring the industry, although there are many possible variations on each.

Representations of each of these models are presented in Figure 3.

In the case of restructuring to competitive markets, the operation and control of the transmission (T) and distribution (D) system (in essence the grid) is still viewed as a natural monopoly, because of the requirement of central dispatch and the difficulty in building competing T&D systems given the costs and right-of-way barriers to entry. As such, the grid operations and T&D infrastructure have remained monopolies in almost all jurisdictions that experienced restructuring. Management of the grid to maintain reliability is handled by such entities as independent system operators (ISOs) or regional transmission organizations (RTOs), with oversight by regulators and other stakeholders.

Model 1 – Vertically Integrated (monopoly at all levels)

This is the traditional vertically integrated utility model. A single monopoly company handles the production of electricity and its delivery over its own transmission and distribution network to final consumers. Generation is not subject to competition and no commercial and industrial (C&I) or residential consumer has any choice of supplier (with the exception of self-generation).

State-owned electric companies around the world and many traditional IOUs fit this model. The state-owned utilities do not have the inherent conflict between owners and consumers since the consumers "own" the company (at least, in theory). For IOUs, there can be a conflict as the utility owners or debt holders (e.g., stock and bond holders) are not necessarily the utility's customers. Even in restructured markets, one can find examples of this vertically integrated model with a monopoly service area (such as a municipally owned utility) selling electricity to its customers. There are more than 2,000 publicly owned utilities in the U.S., serving about 15% of the customers.

Model 2 – Single Buyer (limited competitive generation)

In restructured markets, different arrangements have been pursued to facilitate wholesale competition. One approach allows a single buyer, the purchasing agency, to choose from a number of different generators. Direct procurement of transmission service from competing generators to final customers is not permitted. The purchasing agency has a monopoly on transmission networks and sales to final consumers. This model allows for the integrated utility to introduce competition from independent power producers, or IPPs, that own power generation facilities. The Single Buyer model is most commonly associated with jurisdictions where a vertically integrated utility remains (often state-owned).

Model 3 – Wholesale Competition of Generation

Many countries prefer the model of Wholesale Competition to the single buyer model. This model allows Discos[3] or load serving entities (LSEs) to buy wholesale electricity[4] directly from competing producers on the transmission network and deliver this electricity over a distribution network to customers. Discos or LSEs may still have a monopoly over final consumers. There is open access to transmission lines for delivery of energy from any generator to carry power to any customer. A system operator manages the transmission system and generator dispatch. This system operator is independent of the other major market participants (generators, Discos, LSEs, and customers).

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3 A "Disco" is a company that both owns the distribution wires and retails electricity. In Model 3, Discos continue to serve their captive customers at regulated rates. In Model 4, a retailer is a merchant who sells electricity to final customers, but does not own the wires over which the electricity is transported; this is the purest form of retail competition. In some regions, Discos are allowed to continue to serve as retailers in competition with non-wires retailers often driven by the problems of non-technical losses (i.e. theft). Sometimes, a retailer will be created as a separate company affiliated with a Disco, which is not ideal even if there are strong requirements for the two companies to not share information.

4 Wholesale electricity is the electricity after the point of generation, as it exists on the transmission network, before the electricity reaches final customers.

Model 3 is close to the UK system as it operated immediately after it was restructured in 1990, as well as some places in the U.S. and other restructured markets in Australia, New Zealand, Asia, and Latin America. It is probably the most common restructuring approach but with variations to reflect certain local political, socioeconomic, or technical peculiarities.

Model 4 – Retail and Wholesale Competition

This electricity market model allows all customers to choose their electricity supplier. There is open access to transmission and distribution wires, and as in the case of the Wholesale Competition model, transmission and distribution companies are usually still regulated as separate Transmission Service Providers (TSPs) and Distribution Service Provider (DSPs) or an integrated "Wires and Poles" Transmission and Distribution Service Provider (TDSP). Thus, the distribution (delivery) is separate from the retail activity, and the latter is competitive. A retailer is a merchant who sells electricity to final consumers but does not own any distribution wires.

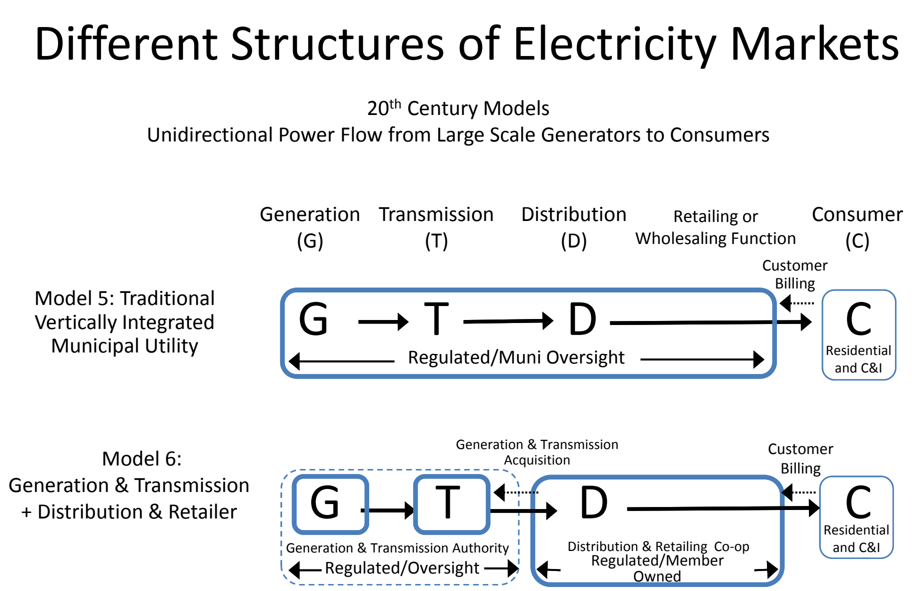
The UK, Norway, Chile, Australia, and some U.S. states have systems that approximate to this model, or are in a phased transition. The retail choice program in Electric Reliability Council of Texas (ERCOT) represents arguably the most competitive retail electricity market in the U.S. The market has been open since 2002, allowing even the residential customers to choose their electricity providers. However, municipally owned utilities and cooperatives have decided not to participate in retail choice. Still, there are tens of retail electricity providers (REPs) offering several hundred rate plans. In this model there are many possibilities. In the UK, most retailers sell bundled natural gas and electricity. Customers can choose and change retailers as contracts expire. This model is also expected to facilitate deployment of smart grid (e.g., smart thermostats, remote control of appliances, time-of-use pricing). However, the REPs in the ERCOT market have been slow to incorporate these technologies into their offers presumably because of uncertainty of return on investment.

PUBLICLY-OWNED UTILITIES (NON-PROFIT OWNERSHIP)

Electric grid assets can be owned by non-profit entities, such as municipal and federal governments or member owned cooperatives

FIGURE 4:

Not-for-Profit Municipal Utilities, Generation & Transmission Authorities, Distribution & Retailing Co-ops



(see Figure 4). In these cases, the structure of the grid is similar to those models representing grids with for-profit ownership. In some cases, there is a mix of for-profit and non-profit ownership of assets on a single synchronized grid.

Model 5 – Vertically Integrated Municipally Owned Utilities

Some cities own their own electric utility. The municipally owned utility structure (Model 5) in Figure 4 is similar to the investor-owned, fully-integrated vertical Model 1, where the residential, commercial, or industrial consumer have no choice of supplier (with the exception of self-generation). Advantages to the electricity consumer can include the elimination of corporate income and property taxes that would be included in the cost of IOU-provided electricity service, a source of income for the municipal government, and local control. Disadvantages can include a lack of scale that may increase costs.

Model 6 – Administrations, Authorities, and Cooperatives (Co-Ops)

Figure 4 also shows the model successfully deployed in areas that did not have sufficient population density to attract service by investor or nearby municipally owned utilities. These areas were without power until rural electrification efforts began in the 1930's. A few of these organizations also experienced significant growth in capacity to provide massive amounts of energy for critical World War II projects. Generation and transmission services can be provided by Federal Power Marketing Administrations (such as the Bonneville Power Administration), agencies such as the Tennessee Valley Authority (TVA), state created non-profit firms (e.g. Lower Colorado River Authority), or generation & transmission (G&T) co-ops. These G&T entities generate and transmit bulk power to rural co-ops or municipal utilities. Even with the separation of generation and transmission from distribution, the consumer has no choice of supplier (again, with the exception of self-generation) but possibly has the ability to influence investment decisions (e.g., as a co-owner of a cooperative or citizen of a city that owns its municipal utility).

4 | PERSPECTIVES ON THE FUTURE

A fundamental assumption that led to the initial regulatory model of the electric industry was that the provision of electricity was most economically achieved through scale economies that favored vertical integration and centralized generation. Accordingly, the regulatory model was based on the notion that regulatory commissions need to ensure that the consumers pay as little as possible for reliable and pervasively available electricity service. In order to achieve that main goal, regulators have sought to oversee the utilities to ensure that the utilities are investing in available technology to keep current prices low, allow the utilities to make sufficient profits so they can raise necessary funding in the capital markets, and monitor to ensure the utilities are operating in a manner that does not cause undue harm to public health and welfare. When it works well this is a political process that appropriately allocates costs and benefits in a complex, rapidly changing environment. When the structure does not function well, customers can suffer from increased costs and poor service.

The restructuring of the electricity industry has led to competition in wholesale markets, and, in some cases, retail markets. More efficient generation technologies, such as combined-cycle-gas-turbines, have benefited from and supported wholesale electricity competition. In most jurisdictions, including both restructured and traditionally regulated, policymakers have also been increasingly pursuing environmental goals. However, maximizing environmental performance and maximizing economic efficiency are distinct goals, and are sometimes in tension with one another.

Tax policies (federal and state), state renewable portfolio standards (RPS) programs, and environmental (air, land, water, climate) regulations have introduced technologies that compete with existing thermal generators. These include wind, solar (both distributed rooftop, and utility-scale PV, concentrated solar thermal), demand side management (energy efficiency, demand response), and storage (batteries, flywheels, compressed air). Some communities promote these technologies for social and environmental reasons as well as reliability (e.g., community solar). It is interesting to note that RPS programs can be partially driven by state economic development goals as well as environmental considerations. State regulators have modified their rules to accommodate these technologies.

These trends pose continuing challenges for grid operators. Distributed resources and demand side participation can be particularly challenging with retail competition. The retail market structure may not encourage the investment required to exploit load that may be flexible. The relative ease for end-consumers to switch retail electricity providers can create disincentives for investments in intelligent distributed resources. The trend toward distributed energy resources represents an important departure from historical practice.

TECHNOLOGICAL CHANGE CONTINUES

Intermittent renewable electricity generation technologies do introduce some challenges for utilities, ISOs, and regulators. In competitive markets renewables enjoy certain advantages. The zero fuel costs, low operating costs, and low life-cycle emissions encourage deployment. However, the intermittency of these sources is forcing the grid operators to depend upon (and value) more flexible generation sources elsewhere on the grid to compliment the intermittent renewables in order to maintain reliable electric service. It is important to note that baseload power generation (e.g. nuclear and coal) with more constant output typically also needs to be complimented with flexible dispatchable generation to adjust the total power supply to match the constantly varying demand. Wind power fits the existing traditional electricity model fairly well because it is generally implemented as large-scale wind farms remote from the load, a typical scenario for a modern ac power system. The major challenge anticipated in system dispatch by the grid system operator is to maintain stability and reliability by "firming" the renewable generation by simultaneously varying the output of traditional gas, coal, or hydro generation. To date, relatively modest levels of intermittency related to wind and solar power generation within major North American grids are handled via adjustments to existing system dispatch protocols that were already in existence to handle the intermittency related to unpredictability of loads and generator trip-outs. Improvements in wind and solar generation forecasting techniques have also helped. Despite the challenges of forecasting loads and renewable generation output, some small electric grids, such as on Oahu, Hawaii, have been able to reach high percentages of wind and solar generation relatively quickly, through the deployment of new technologies and regulatory adjustments.

Many believe that eventually solar photovoltaic (PV) power will be more widely adopted than wind power. Solar generation is becoming increasingly attractive. PV can be installed in smaller distributed applications or large utility scale solar farms (30-100MW+) as an IPP. Solar PV power output is inherently dc and appears to be relatively well matched to many modern load patterns. For example, peak solar PV generation occurs during the summer daytimes when air-conditioning loads are highest, though the exact hourly timing of the peak PV and air-conditioning load usually does not precisely match. More importantly, PV shows promise of becoming cost effective from large utility-scale installations, community level systems attached to neighborhood distribution circuits, and with smaller distributed rooftop installations on the home or business. Solar PV is a technology that brings back the initial concept of neighborhood dc power, but its integration can now be made even more robust by overlaying a dc microgrid with the existing ac transmission and distribution grid for those customers with the most demanding reliability requirements.

Wind and solar power show promise to be truly disruptive, as they might become (based on current cost trends) the least expensive ways to generate electricity in some regions on a levelized cost basis, not considering system costs such as new transmission lines and balancing generation. Incremental transmission and balancing costs may or may not be consequential. The levelized cost of electricity (LCOE) is a commonly used metric for comparing different generation types. Typically expressed on a $/kWh basis, it combines capital and operating costs to estimate the amount of money that it takes for a particular electricity generation plant to produce a kWh of electricity over its expected lifetime [12].

The impact of renewables is even more pronounced in dispatch decisions and spot markets for electricity, where the marginal cost of providing the next kWh is what matters. Since its marginal costs are effectively zero, wind can be dispatched at prices lower than conventional resources, even at negative prices at times, owing to federal tax credits and renewable energy trading credits. Such prices, driven by out-of-market subsidies provided to these generation technologies, can undermine energy price signals in competitive electricity markets. However, many of these subsidies expire over time. Renewable energy proponents sometimes argue that the competitive markets themselves are not complete since they do not fully internalize many important factors, such as health impacts from air emissions. Many emissions regulations have been implemented since the 1970s, helping to internalize some of these costs.

Renewable electricity generation output is both predictably variable with such factors as the time of day and sometimes intermittent with the changing of wind and cloud patterns. Grid operators have managed to incorporate significant amounts of wind power to date with little impact on reliability. However, as far larger amounts of renewables are installed, fast ramping thermal generation, energy storage, and more flexible load are likely to become more important. The electric industry will need to balance the grid using the legacy grid assets (e.g., natural gas power plants), even more advanced forecasting techniques, and perhaps eventually increased forms of energy storage. These options, however, are not mutually exclusive, and these technology changes are driving changes in both regulation, wholesale market structure, and financing of the electric sector.

Demand that is responsive to price signals (e.g., lower when prices are high) can reduce generator or utility revenues. Energy storage can be deployed in a number of places on the grid, including on the customer site that might enhance the level of demand response. Only a few of these storage configurations are financially attractive at this time. As storage prices decline, more regionally specific market applications for grid storage may become economic for various grid needs. Storage can be co-located near intermittent renewable generation to "firm" its output. Large-scale storage such as CAES, pumped hydro, or thermal storage could be attached to the transmission system. Local storage such as batteries could be installed at various interconnection points with the distribution network. "Behind the Meter" storage can be co-located with a customer's load to reduce utility demand and energy charges.

There are other technologies that might impact the future of the electricity grid. Some have been around a long time but technology improvements and recent changes in market rules might render them more attractive. For example, micro-turbines that burn natural gas to generate electricity might make sense in some places as a distributed resource. Combined heat and power (CHP), which is one of the most efficient ways to utilize fuels, in large commercial and industrial applications may prove to be attractive for communities or municipalities. Batteries are not new either, but new material compositions may bring lower battery costs, in which case their deployment can be accelerated. Other technologies are relatively newer with a relatively small number of units deployed. Storage options such as compressed air energy storage (CAES) or thermal storage can find larger applications if they can be optimized to reduce costs. The storage of CO_2 through carbon capture and sequestration (CCS) might allow some traditional thermal capacity to remain as part of grids that might need to operate with lower CO_2 emissions. Small modular nuclear reactor (SMRs), the first "commercial" site of which might be built in the next few years, can be a game-changer if they prove to substantially reduce costs. Finally, there is significant activity in energy efficiency, conservation, and flexible loads that can alter load profiles, and, hence, the way grids operate by changing the relevance of demand-side participation.

FINANCIAL CHALLENGES FOR UTILITIES

Utilities face increased affordability of distributed generation, particularly rooftop photovoltaic (PV) panels, and stagnant or declining electricity demand in the U.S. since 2007. These trends can lead to the underutilization of large, costly, and long-lived fixed utility assets (e.g., power plants, transmission, or distribution assets) compared to the expected utilization rates that were used in the original investment decision-making and regulatory approval. Thus, these assets are at risk of becoming a "stranded cost" or a cost that cannot be fully recovered. When markets were being restructured, utilities were concerned that their investments recently approved by the regulators would not recover their costs if the energy prices declined rapidly as a result of competition or new technology. Finding this concern legitimate in certain cases, policymakers granted ways to recover these stranded costs.

In restructured markets, new technologies can make large and long-lasting investments economically obsolete relatively quickly. The electric system includes transformers, transmission lines and power plants that are 50 years old or more, for example. The financial markets are reluctant to make these longer-term investments in an uncertain environment, at least not without a significant premium to cover the risk or without assurance that stranded costs will be recovered. The regulatory response can be to identify stranded costs that will be recovered independent of system evolution. Stranded cost recovery can in some circumstances shift the risk from the utility investors to the consumers by increasing the cost of electricity to customers. For example, if a utility is able to charge its customers for stranded assets (e.g., those retired early due to lack of economic operation), then the customers' electric rates (e.g., \$/kWh charged on their bill) or fixed charges may increase even while the fuel costs of electricity generation decrease creating a customer backlash that may be of concern to regulators.

The issue of declining revenues, due to distributed generation and lower demand more generally, impacts the ability of electric utilities to access less expensive capital to fund new investments. As noted by Peter Kind in his report to the Edison Electric Institute, "Since practically all utilities have an ongoing need for capital to fund their capital expenditure programs, the industry has developed financial policies intended to support the access to relatively low-cost capital in (practically) all market environments. Under traditional cost-of-service ratemaking, customers benefit through lower cost of service and, therefore, lower rates" [13]. If future revenues become more in doubt for utilities, then they are pressured to raise their rates (e.g., $/kWh charges) to pay existing debts, and future capital might come at a higher cost, again putting upward pressure on electricity rates. These upward pressures on electricity rates only enhance the incentives for further electricity conservation (or load defection to distributed generation) by consumers, a trend described as the "utility death spiral." The extent to which this death spiral will play out is uncertain, but it is one of the many important motivations for understanding the Full Cost of Electricity. One of the policies that have been helpful to the expansion of rooftop solar PV around the country, net metering, has been under pressure. Utilities observed that there was a loss of revenues resulting from the expansion of rooftop solar while they are required to maintain the same infrastructure under rates approved by regulators for larger loads. At the time of writing, a couple of state utilities have revised their rules to address this concern deeming it legitimate from a ratemaking perspective. Other states and utilities are evaluating similar policies.

CUSTOMER ELECTRICITY COSTS

A customer's electricity bill consists of different charges. In jurisdictions without competition, the rate will generally reflect generation and T&D costs but be set by the regulator or the government. In competitive markets, the regulated T&D charges are fixed over a relatively long period of time. These rates are fixed because the assets are long-lived (measured in decades) capital investments generally financed with long term debt and amortized over 20 to 30 years. The unregulated cost of electricity (energy charges) will vary along with the wholesale price that varies over the course of days, seasons, or longer commodity price or technology cycle periods, but utility economists have become more expert at achieving an average cost due to the predictability of the average (not instantaneous) cost and load. The proportion of fixed charge related to long-term capital asset investments and variable energy generation related charges in a customer bill have varied over time and across jurisdictions.

In some states, ratemaking policies allow for some cross-subsidies between residential and larger commercial and industrial consumers. Block rates can be pursued to encourage conservation and efficiency (e.g., much higher rates above a certain level of consumption) despite sometimes-lower fixed cost amortization costs with higher volumetric energy sales. Fixed charges can increase meaningfully if new transmission and distribution investments are mandated by the regulator or the legislature to accommodate remote resources such as wind or solar (e.g., Competitive Renewable Energy Zone transmission lines in ERCOT). These increases in fixed charges may or may not be offset by decreased generation costs.

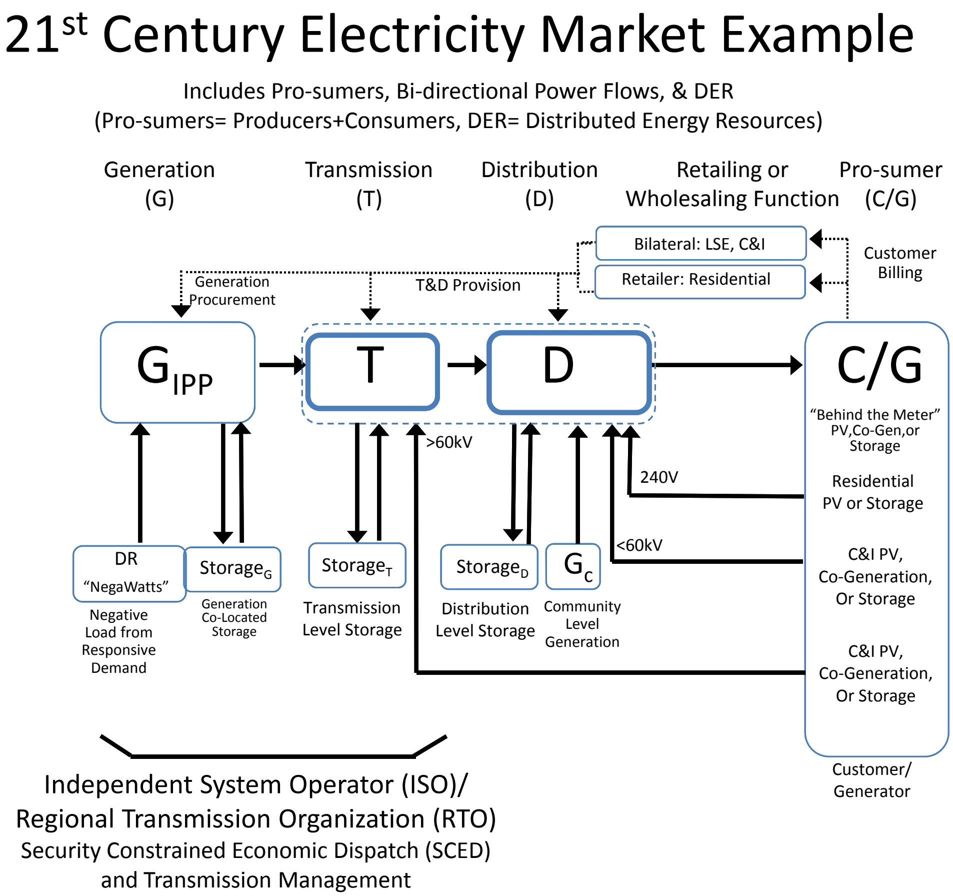
Historically, reliability has been an important objective of all electricity systems. In some competitive regions, generators are compensated for the capacity they make available to the grid via long-term capacity markets in addition to energy they sell into the energy markets every hour. These capacity charges are also fixed in customer bills for extended periods of time. As such, changes in customer bills can arise from regulated infrastructure charges or capacity charges as well as market-based energy charges. In recent years, given that the low price of natural gas has kept wholesale electricity prices very low, increases in customer bills in competitive jurisdictions are most likely the result of investment in new T&D and/or generation infrastructure.

EVOLVING ELECTRIC GRID ORGANIZATIONAL STRUCTURES

Technological progress and cost reductions have introduced additional complexity and challenges to the previously described utility models of Figures

FIGURE 5:

Disruptive Technologies to the Existing Utility Model



3 and 4. These changes are fostering even more complex business and regulatory models where customers can increasingly purchase electricity services from multiple vendors for multiple purposes (e.g., demand response (DR), distributed generation, energy storage) and in multiple ways (see Figure 5). Storage and generation systems can technically be located on multiple parts of the grid depending upon capabilities and needs.

Community level solar systems connected to the distribution system can reduce transmission loading and allow distribution companies or cooperatives to own small-scale generation for the first time or provide unique customer ownership opportunities for those who cannot install rooftop PV on their residences. Rooftop PV or cogeneration systems at homes and businesses can be a utility-owned distributed generation resource or customer-owned generation that reduces utility revenue. All of these configurations can provide an opportunity to improve (or complicate) the utility model, their finances, and in some cases the technical operation of the grid. The emergence of distributed energy resources (DERs) either on the utility side of the meter, or behind the customer meter, may become a transformative force to the utility industry. While the discussions of such concepts as "transactive energy" and the models of distributed system platforms (DSP) or independent distribution system operators (DSOs) are beyond the scope of this paper, these concepts are part of ongoing restructuring efforts in a number of states, These efforts are attempts to accommodate new technology alternatives, associated business structures, market design, and the supporting regulatory structure to meet stakeholder objectives for their 21st century energy systems [14][15][16][17].

There will also likely be an increased demand for newer and more customer-centric regulatory frameworks that allow an increased number of technologies to be owned and operated by a larger number of players that serve more diverse customers.

5 | CONCLUSION

For a century, the scale economies associated with large centralized generation technologies encouraged vertical integration, drove down the cost of electricity, fostered universal access that improved citizens' quality of life, and provided for reliable electric service. The structure of the electricity industry started to evolve significantly starting in the 1970s. Higher fuel prices, environmental concerns, technological innovations and efforts to improve the economic efficiency of electricity service led to the rethinking of the traditional vertically-integrated, regional monopoly model. In the late 1970's and 1980's a series of government decisions deregulating wellhead natural gas prices and the pipeline industry made natural gas-fired electric power much less expensive. These efficient non-utility co-generation/CHP gas powered generators were some of the first disruptive technologies and firms that threatened the traditional vertically integrated utility model.

By the mid-1990s, policy makers began to restructure the electricity system, seeking to promote innovation and reduce electricity costs while incorporating policies that addressed environmental concerns. Federal and state governments implemented environmental regulations, tax credits, and other programs that encouraged deployment of renewables such as wind and solar.

Continuing declines in the cost of wind and solar PV, inexpensive natural gas combined with flexible and efficient combined cycle gas plants, micro grids, and energy storage and demand response systems with progressively lower costs continue to provide opportunities to improve the traditional utility business model. These technology developments are strongly encouraging the industry to consider new technology and business models, policy makers to consider alternative regulatory and electricity market structures, and electricity customers to pursue self-generation, storage, or responsive demand capabilities that have the potential to significantly reduce utility revenues and profitability. With so many moving pieces, the policy and investment environment can be uncertain. The companion papers of the FCe- project and related research by team members offer more insights into the technologies, trends, or considerations that lead to disruptive changes and uncertainty. ■

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