WESTERN AREA POWER ADMINISTRATION
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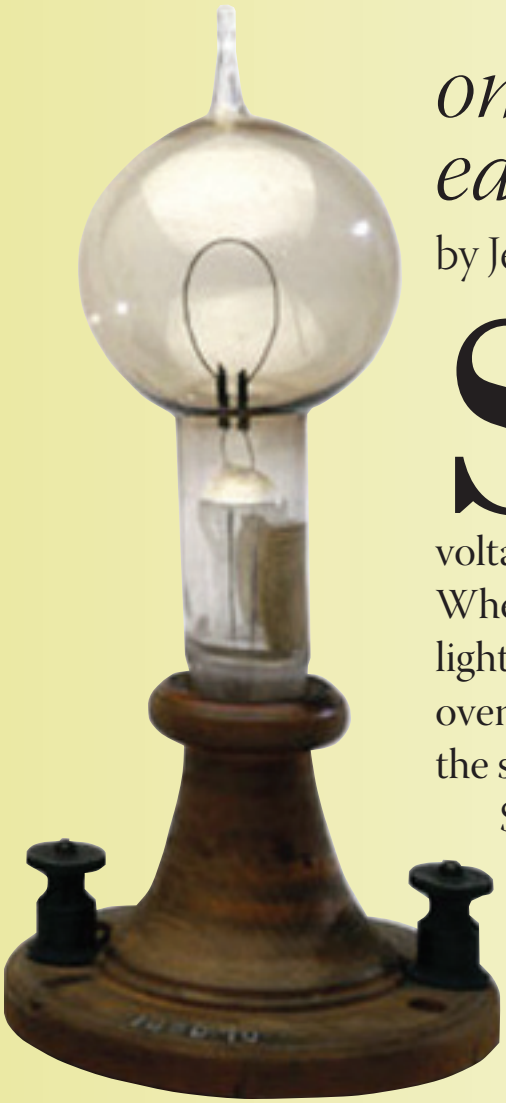
CONNECTING COMMUNITIES SINCE 1977

DEC. 5, 2003

Shining light

on the utility industry's earliest foundings

by Jeff Hein



Since the invention of the light bulb, man has worked to harness the power of electricity. It's hard to imagine our modern society without pulsing voltage available at the flip of the switch. Whether it's powering up your computer, lighting your school or heating up your kitchen oven; instant energy is as expected as the sun's rising each morning.

So let's take a journey back and shed light on how Edison's and Brush's inventions in 1879 led to the modern utility industry we know today.

Note: *The following series about the history of the U.S. electric utility industry was developed by Jeff Hein, a former Western substation engineer, as part of his master's thesis research.*

Shining light on electricity origins, early developments

The roots of the modern day electric utility industry can be traced back to two events that occurred in 1879. The first occurred when Charles Brush invented a dynamo and arc lamp lighting system for street lighting, which he put to use in Cleveland, Ohio. That same year, Thomas Alva Edison and his team of researchers invented the incandescent light bulb for home lighting, the predecessor of the light bulb in use today.

In New York City in 1882, Pearl Street Station was the first central electricity-generating station constructed to support the light bulb invention. Using a direct current, 100-volt generation and distribution system, Pearl Street Station used reciprocating steam engines to provide the mechanical energy required to create electricity. Lighting was its first application.

In 1878, Edison founded the Edison Electric Light Company. It evolved into the General Electric Company by 1892. Edison was a major stockholder.

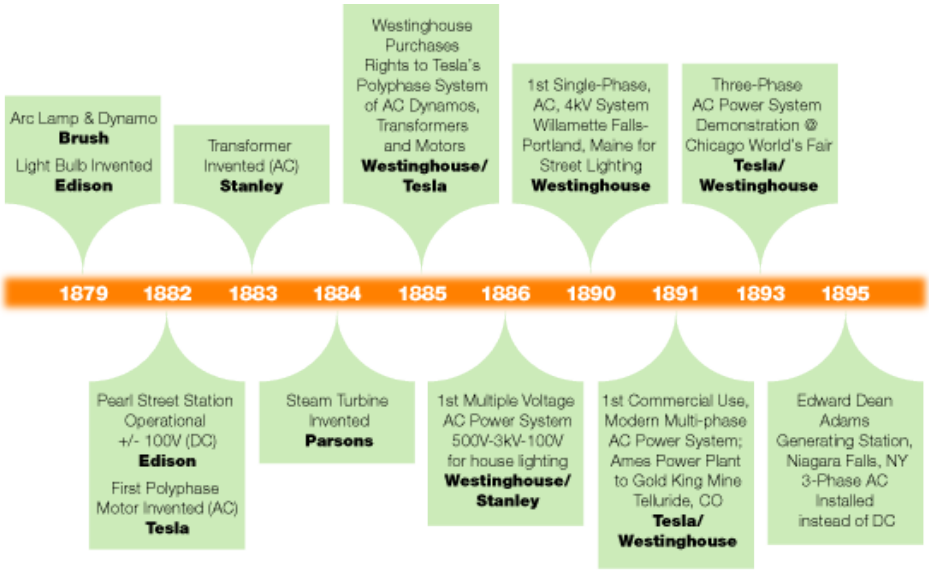
The need for electricity would grow as appliances, such as irons and even electric streetcars, were introduced. While Edison and other predecessors used wood or coal, which was dirty, they were developing a market for cleaner electricity.

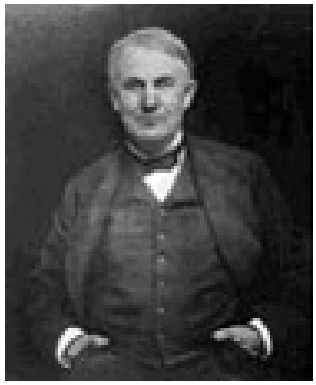
Development and competition

By 1880, electricity was being hailed as a modern marvel that would revolutionize households and industry nationwide. Optimists envisioned increased demand for electricity and others sought entry into this growing market. Central generating stations and distribution systems (wires and poles) began sprouting up in many cities. Competition among power providers was commonplace. Initially, the U.S. electric utility industry operated in a competitive, market-based environment.

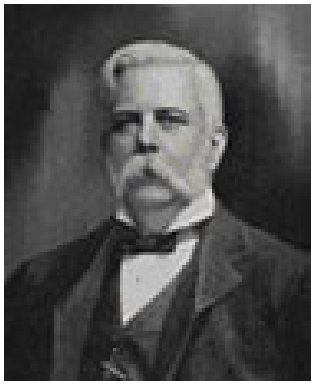
Because low voltage restricted distribution to about one mile from the generating station, many small scale generating stations and distribution systems were built. In Chicago alone, 45 electric utilities competed for customers. This industry design was repeated again and again within cities throughout the United States.

Electricity's beginning: a timeline

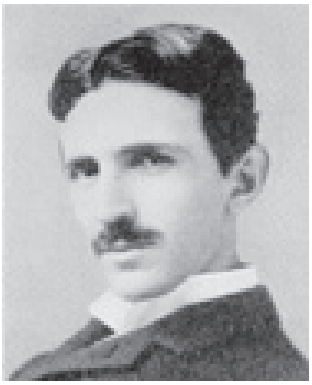




Thomas Alva Edison (compliments of General Electric)

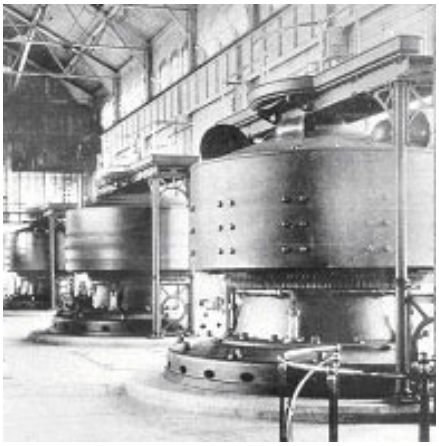


George Westinghouse (compliments of General Electric)



Nikola Tesla

Edison's first light bulb. (compliments of National Museum of American History, Science Service Historical images collection)



The Edward Dean Adams power station harnesses the power of Niagara Falls. (compliments of General Electric)

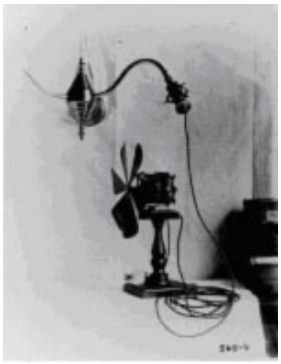


Image of an early electric fan. (compliments of General Electric)

Competing technologies

During this same period, another form of electricity—"alternating current"—was being developed. The primary developers were Nikola Tesla, William Stanley Jr., and George Westinghouse.

In 1883, Stanley invented the first modern-day transformer used in AC electrical systems. Tesla invented the AC polyphase motor in 1885 and married it with the transformer. AC technology was more efficient because it could increase low-voltage generation to a higher voltage for long distance transmission, then back to low-voltage distribution for end use. While DC power systems had a head start and were more widely used than AC systems, in 1882, AC power systems were still being developed and installed. Together, with the finances of George Westinghouse, the AC electric system proved to be a strong competitor to DC systems. Westinghouse Electric Company was founded in 1886. The first AC system, upon which today's is based, was built in 1891 to provide power from the Ames Hydro-power Station to the Gold King Mine near Telluride, Colo.

These two technologies would eventually compete for control of the U.S. electricity market. This head-to-head competition occurred during the development of the Niagara Falls' Edward Dean Adams power station. The Niagara Power Commission, wishing to deliver power to Buffalo nearly 23 miles away, awarded a contract to the Tesla/Westinghouse AC generators, based on their Chicago World's Fair exhibit. This was a major defeat for Edison and the DC power systems he envisioned.

1896 to 1928:

Electric industry evolves–competition, consolidation, state regulation, tremendous growth

A major development in the electric utility industry occurred in 1903. Chicago Edison, under the guidance of president Samuel Insull, installed a turbine-generator set that produced 5 MW of AC power at Fisk Street Station in Chicago. A turbine-generator set was revolutionary because it used a new technology known as a steam turbine as the generator's prime mover. The rotating steam turbine, developed in England in 1884 by Charles Parsons, was far superior to its predecessor, the reciprocating steam engine.

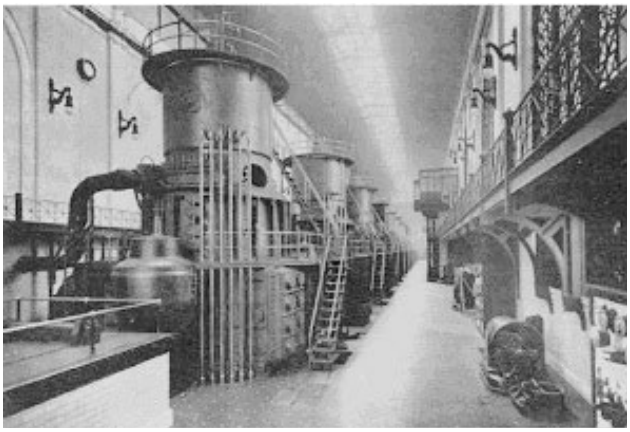
The new steam turbine was much smaller, produced equal amounts of energy, and could be scaled up to produce more power for little additional capital cost. These new machines could now produce more electricity at a cheaper cost. Adjusted to 1992 terms, new AC technologies lowered electricity costs to $1.56 per kilowatt-hour in 1912 compared to a rate in excess of $4 per kWh in 1892.

The downfall of the widespread DC electricity system Edison envisioned was imminent.

Charles Parsons

Samuel Insull

Franklin Roosevelt


The Fisk Street Station uses new 1903 steam turbine technology developed by Commonwealth Edison Company. (Courtesy of the National Museum of American History.)

Consolidation, regulation, early growth

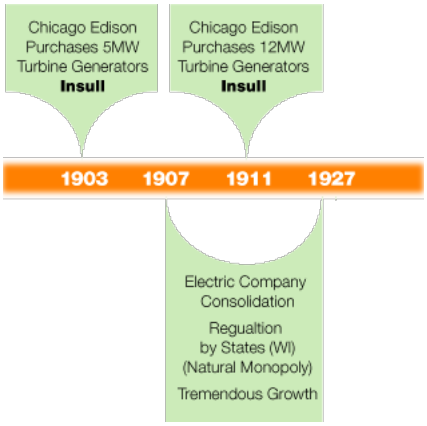
Insull realized that a competitive market environment would not result in enough profits to pay back investment costs. He began acquiring other utilities, eliminating competition—and thus began consolidation. By 1907, Chicago Edison had acquired 20 other utility companies and changed its name to Commonwealth Edison.

Consolidation occurred in many other cities, with the local electric utility controlling the market—a natural monopoly.

Using the railroads as precedent, initially cities, then states created pubic utility commissions to regulate electric companies and protect consumers from price gouging. States assumed jurisdictional authority over electric utilities which was initially held by local government. Utilities were protected from competition and, in return, were obligated to serve all customers.

As a result, during the 1910s and 1920s, utilities saw tremendous growth and were able to charge their expanding customer base for all services they provided. Utility generation and transmission expanded from 5.9 million kWh in 1907 to 75.4 million kWh in 1927, while per unit costs of electricity declined 55 percent.

Electrical industry timeline: 1903-1927



1927 to 1936:

Electricity holding companies in control

During the 1900s, Commonwealth Edison and other utilities began to form an operational structure known as a holding company. Holding companies acquired various utilities (electric and railway). These were known as operating companies. Organized into a pyramid scheme covering many states, holding companies acquired subholding companies and the corresponding operating companies. The holding companies would interconnect their operating companies' systems to improve operating efficiencies. By 1927, three holding companies controlled 45 percent of the entire U.S. electric utility industry.

The holding company structure offered many benefits. Operating companies used the holding company's centralized engineering, management and purchasing services. In addition, holding companies increased reliability by interconnecting their operating companies. The electricity system grew quickly.

By 1928, holding companies were abusing this structure. The holding companies were essentially monopolies and began charging exorbitant service fees and overvaluing purchases, which were then added to the service rate.

The interstate operating structure allowed holding companies to evade state-based regulatory commissions because these issues were under the jurisdiction of the Federal government, and there were no Federal authorities providing industry oversight.

Public distrust of these holding companies came to a head when the stock market crashed in 1929. Many investors lost their investments in holding companies because their weak organizational architecture was susceptible to complete collapse.

Franklin Roosevelt, campaigning for the presidency in 1932, promised to reform the corrupt electric utility industry and create government agencies to provide electricity to rural areas, long ignored by the electric utilities.

Federal intervention

Roosevelt was true to his campaign promises. First, with the approval of Congress, he created the Tennessee Valley Authority in 1933 and the Rural Electrification Administration and the Bonneville Power Administration in 1935.

These government agencies proved that electricity could be generated and delivered cost effectively to remote, rural areas. As a result, the standard of living in these remote areas rose tremendously. These rural loads proved to be the largest customer base in the country at the time.

Secondly, to prevent future abuses similar to the 1920s, Congress passed the Public Utility Holding Company Act of 1935. PUHCA created effective state and Federal regulations for regulating the holding companies.

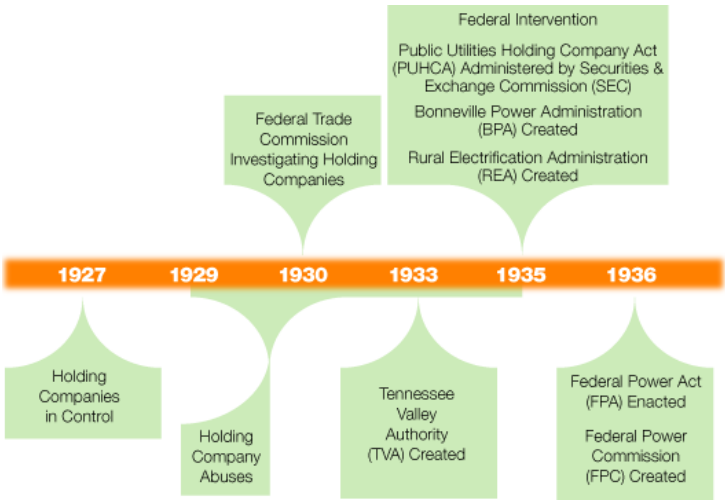
Federal Power Act

Enacted by Congress in 1935, the Federal Power Act increased the Federal Power Commission's responsibilities to oversee and "regulate the transmission and sale of electric energy in interstate commerce." Originally, the FPC was established to oversee/regulate power projects on navigable waterways under the Federal Water Power Act.

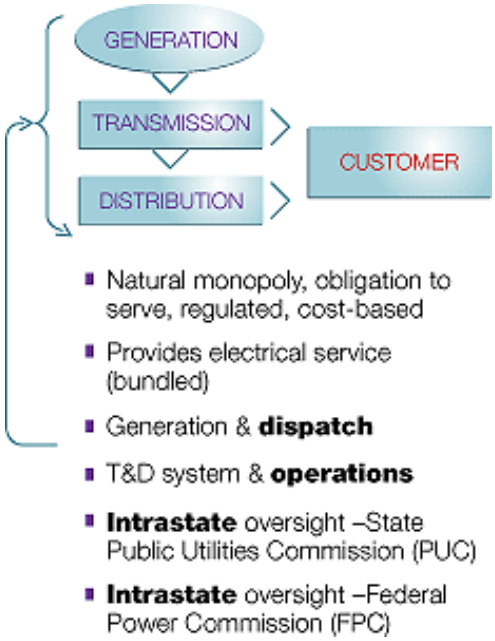
Vertically integrated operations

The post-Federal intervention era created the foundation for vertically integrated electric utility companies. Operating as natural monopolies primarily in or near urban areas, they were vertically integrated, which means they were responsible for providing generation, transmission and electricity distribution to customers. To control the balance of energy supplied and used, each utility created a control area. Control areas ensured system operation by matching electrical generation to load requirements and use. Regulatory oversight was the responsibility of state

Electrical industry timeline: 1927-1936



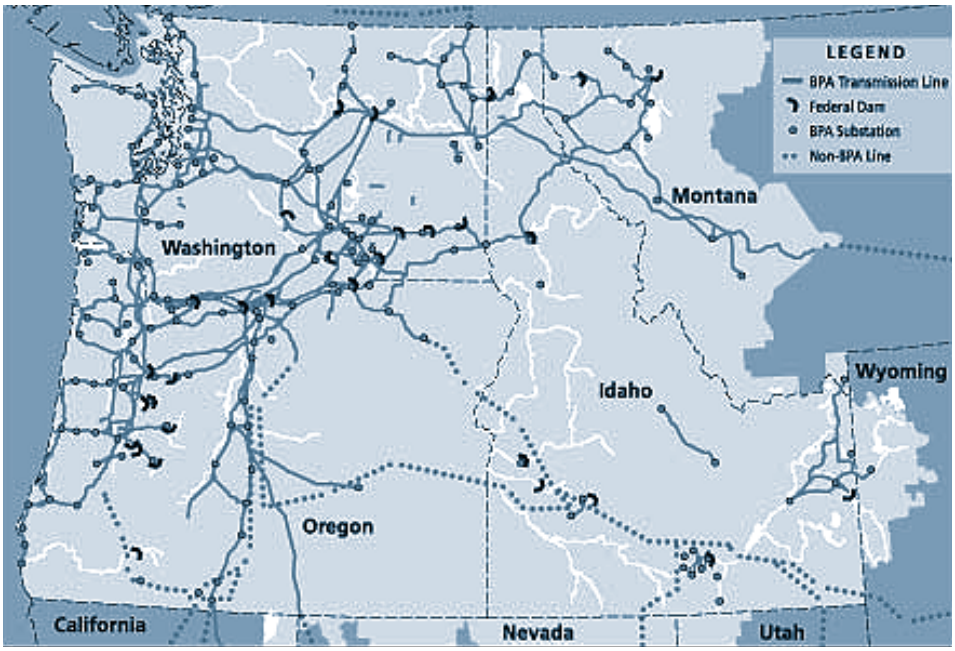
Tennessee Valley Authority serves more than 8.3 million consumers with wholesale electricity in an area from Mississippi to Virginia.



public utility commissions for investor-owned utilities and the role of municipal leaders for municipal power agencies. To ensure customer abuses did not occur, service rates were under constant scrutiny through the Uniform System of Accounts.

Operating in a regulated, cost-based environment, utilities planned and built infrastructure to meet the needs of the customers they were obligated to serve. The utility recovered its operating costs plus a regulated profit (approximately 10 percent) through approved service rates. Electric utilities were under state PUC oversight for intrastate activities, in practice, due to their vertical integration structure and bundled services operation. Federal regulations created in 1935 governed interstate activities and PUCs reviewed every aspect of utility operation, from siting to service requirements, through final rate development.

Throughout the '20s and '30s the utility industry continued to grow and grow quickly. Utilities constructed generation near their customers in urban areas to reduce system losses.



Bonneville Power Administration's more than 15,000 miles of high-voltage transmission lines serve the Pacific Northwest.

As the demand for electricity grew, utilities could add to their system infrastructure with a guaranteed return on investment. Utilities added facilities and got paid for this investment from service rates paid by their customers.

1927 to 1969

Industry technology improves, creates regional interconnection

Once the Public Utility Holding Company Act of 1935 was in place, it took a relatively short period of time before the generation sector realized improved efficiencies of scale. With larger generators, electricity could be generated at greater efficiently and less cost.

At the same time, transmission voltages increased to reduce losses. Larger, central, state-of-the-art generating stations, located nearer fuel supplies and connected to high-voltage transmission lines, began replacing the smaller generating stations connected to lower voltage sub-transmission and distribution lines. This configuration resulted in the cheapest electricity possible while improving reliability and the use of resources.

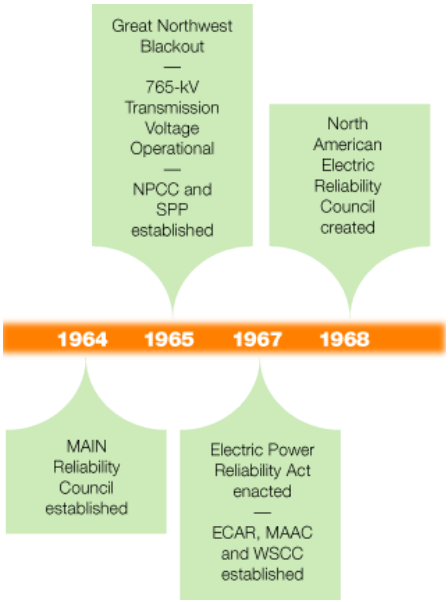
From 1927 to 1967, electricity prices dropped from 55 cents per kWh to 9 cents (adjusted to 1992 terms). As a result of this system, the U.S. electric system evolved from many locally operated, geographically smaller grids, into a highly interconnected one where interstate transmission lines connected many different utility systems. Each utility served its respective customers with its own generation, through purchases with neighboring utilities or by wheeling power from utilities further away. Utilities used contract path pricing for all electrical energy transactions. Individual utility control areas still played a very important role in daily operations and system scheduling electricity to and from neighboring utilities.

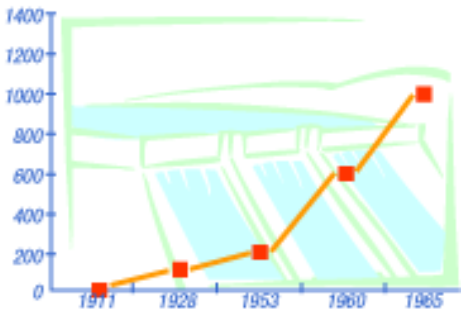
The 1935 Federal Power Act and individual state laws controlled how the utility industry operated through regulatory oversight, primarily at the state level, and to lesser extent, the Federal level. Reliability of the electric system was now both a regional and local control area concern.

Northeast blackout reveals weakness

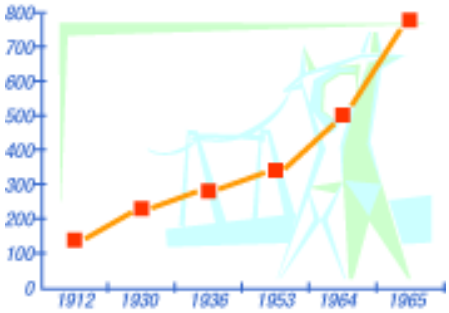
The great Northeast Blackout of 1965 uncovered a weakness in the U.S. and

Grid reliability improves with success, failures

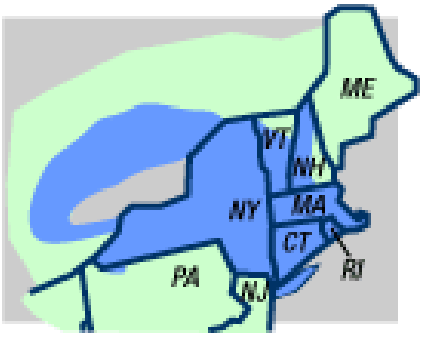




Generator unit MW ratings, 1912-1965



Transmission line voltage ratings, 1912-1965



Great Northeast Blackout of 1965

Canadian interconnected electric grid. A disturbance in one section of a large interconnected grid could interrupt service across a wide geographical area. The blackout interrupted electric service across 80,000 square miles (eight states) in the Northeastern United States and large parts of Canada. This blackout started with a single 345-kV transmission line relaying failure near Toronto.

From that experience, Congress determined that a regional coordinating body should be created to ensure electricity supply reliability over a large geographic area. The North American Electric Reliability Council, or NERC, was formed on June 1, 1968, under the Electric Power Reliability Act of 1967.

Today, NERC is responsible for overall reliability, planning and coordination of electricity supply in North America. NERC is a non-profit volunteer organization comprised of 10 regional councils, which represent smaller regions of North America.

Through this model, North America's interconnected electric power system became the most reliable system of its kind in the world. This is essentially how utilities operated before conservation, deregulation and restructuring legislation appeared.

1970 to 1978

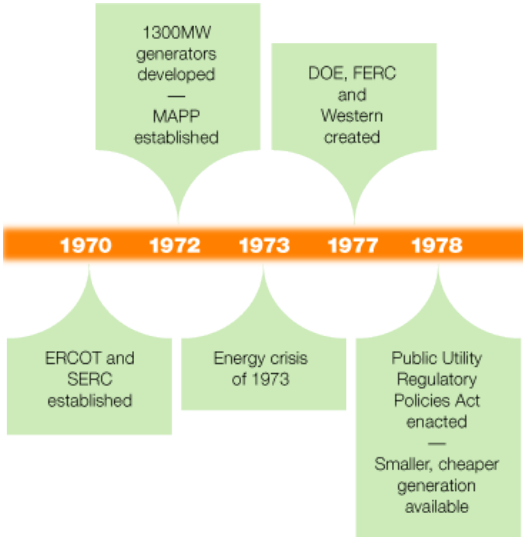
Social concerns, energy crisis aftermath forces new industry course

The 1970s were difficult times for the electric utility industry, with prices of electricity quadrupling between 1970 and 1985. Utilities continued to operate with their customers' best interest in mind, by employing techniques—like large central generating stations and high-voltage and extra-high-voltage transmission—to continue delivering reliable, cheap electricity. Then along came a perfect storm of unforeseen, uncontrollable events—environmental and conservation concerns, an energy crisis, a poor economy, inflation, occupational safety issues and low load growth.

In 1970, Congress passed the Clean Air Act because of concerns about acid rain. This act substantially reduced allowable emission levels from coal-fired power plants. It was followed by the Water Pollution Control Act of 1972. Both laws substantially reduced the amount of electrical power that the large, central generating stations could create. That also reduced the amount of generation available to the interconnected power system.

Fueled by the Organization of Petroleum Exporting Countries' oil embargo, the 1973 energy crisis raised electric generation fuel prices. This led to a focus on conservation and energy efficiency. The Energy Supply and Environmental Coordination Act of 1974 required utilities to stop using natural gas or other petroleum-based products to generate electricity. The Resource Conservation & Recovery Act of 1976, amendments to the 1970 Clean Air Act issued in 1977, the Power Plant and Industrial Fuel Use Act of 1978 and the National Energy Conservation Policy Act of 1978 all contributed to further reductions in the generating capacity of large powerplants.

Electricity timeline shows progress



1977: DOE, Western, FERC created

In response to the precarious national energy situation, several Federal agencies, including the Department of Energy, Western and the Federal Energy Regulatory Commission, were created by the DOE Organization Act in 1977. FERC took over the jurisdictional authority previously assigned to the Federal Power Commission.

This was also a difficult time for the U.S. economy. Inflation grew and economic expansion slowed to a crawl or stopped altogether. The utility industry reflected

minimal or no load growth.

However, many large, central station powerplants were still being built to supply the forecasted load growth. These powerplants were primarily coal and nuclear, which were very costly and took years to build. Not only did these plants cost more as a result of inflation, financing cost increases, safety concerns and regulatory requirements, but once completed, the drastically reduced load growth meant they were no longer needed. The result was excessive generation capacity reserve margins.

These additional costs incurred by utilities were legitimately passed on to electricity consumers resulting in dramatic price increases. Average residential customers paid 2.2 cents per kWh in 1969 and 6.6 cents in 1985. Industrial customers paid 1.5 cents per kWh in 1970 and 6 cents in 1985.

1978: Public Utility Regulatory Policies Act

The Public Utility Regulatory Policy Act's provisions created a tremendous ripple effect throughout the electric utility industry creating a lasting impact that continues today.

The intent of the 1978 law was twofold:

- To introduce more efficient, cheaper, and environmentally-friendly generation technologies.
- To reduce United States' dependency on foreign oil.

New generation technologies cost much less to construct and could produce electricity more cheaply than their large predecessors. Economies of scale no longer favored larger megawatt generators; bigger was no longer better.

For the first time, PURPA's provisions allowed non-utility generators to supply electricity to the bulk power system through FERC-approved qualifying facilities, or QFs. PURPA required utilities to purchase this generation. However, the additional QFs-supplied capacity was relatively small due to limitations imposed upon them.

Other PURPA provisions included the addition of sections 210, 211 and 212 to the Federal Power Act, which gave FERC authority over QF interconnections and interstate transmission service.

In the near-term, PURPA legislation resulted in cheaper, cleaner generation technology development, added to the power system via QFs and larger independent power producers. The most lasting, unintended result of PURPA was the possibility of deregulation of the generator section.

In the 1970s, the natural gas sector was also deregulated under FERC's oversight. This led many to believe the same could be done to the electricity generation sector. Many believed generating electricity was no longer a natural monopoly, since most companies could now afford to build powerplants using these new generation technologies. Many also believed replacing the regulated, cost-based sector with a deregulated, or competitive, market-based approach would result in cheaper electricity through improved business decisions combined with the cheaper generation technologies.

Not knowing the direction the industry would take, utilities began to reduce generation, transmission, distribution and employment costs. As a result, generation and transmission reserve margins and capacity began to decline.

1978 to 1998

FERC calls utilities to deregulate, restructure

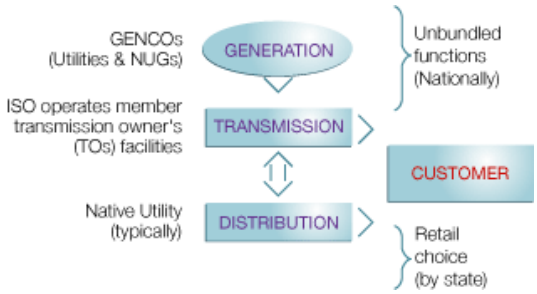
Between 1978 and 1987, other industries in the United States were deregulated, including the airline industry in 1978 and telecommunications in 1984. Further deregulation in the natural gas industry opened access to pipelines and created a "spot market" in 1986 and 1987. Many believed (because of previously deregulated industries) electricity deregulation would lower costs to consumers while increasing supply and improving reliability. The same was thought of the electric utility industry's generation sector.

Energy Policy Act

The primary intent of the Energy Policy Act of 1992 was to create open access to the transmission system for all generating companies—utility-owned as well as qualifying facilities, or QFs, and independent power producers. But, according to some, the playing field wasn't even. Some non-utility generators accused vertically integrated electric utilities of favoring their own generation and of control area operators giving preference to their company's resources. The Federal Energy Regulatory Commission and Congress believed that without open access to the transmission system, the nation would not realize the anticipated benefits of new generation technologies.

Primary provisions of EPAct included FERC approval of exempt wholesale generators. The law also added Section 213 to the Federal Power Act. Under the FPA, exempt wholesale generators could sell electricity in the bulk power market. Section 213 extended FERC jurisdictional authority and oversight over transmission access issues. As a result of EPAct, transmission tariff structures improved, and utilities had to file open access tariffs with FERC before gaining access to lucrative market-rate contracts. In 1992, for the first time, generation added by non-utility generators exceeded that added by traditional utilities.

After passage of the EPAct and through 1995, non-utility generators continued to



report transmission system access discrimination by vertically integrated utilities. In response, FERC, acknowledging transmission was still a natural monopoly and should be treated as such, issued several policy statements. But these still did not achieve the goal of ensuring open access to transmission. To promote generation-sector competition and correct the open access issue once and for all, FERC issued Orders No. 888 and 889 in 1996.

Orders No. 888, 889

These two orders, issued concurrently, were the first attempt at wide-sweeping

changes to promote deregulation of the generation sector. Order No. 888 addressed open access to transmission, while Order No. 889 dealt with access to transmission system information by all interested parties.

Deregulation applies only to the generation sector—moving it from a regulated sector to a competitive one. Restructuring refers to the overall industry, but primarily the transmission sector. Transmission had to be "restructured" to allow for open access. Transmission remains regulated.

Why deregulate the U.S. electric utility industry, the world's most reliable and cheapest system? FERC cited three primary reasons:

- Reduce the cost of electricity through new technologies and improved business decisions
- Accelerate the introduction of new generation technologies
- Provide access to cheaper electricity that existed in other U.S. regions

Order No. 888's primary objective was to promote generation-sector competition and provide open access to the transmission system. FERC outlined six primary provisions to accomplish this:

- Require all jurisdictional utilities to file an open-access transmission tariff
- Require IOUs to functionally unbundle wholesale generation from transmission services
- Create Independent System Operators and operating guidelines
- Encourage reciprocity for non-jurisdictional utilities
- Allow utilities to recover stranded costs
- Identify ancillary services and comparable service to properly operate the bulk power system

"Deregulation" would move the generation sector from a regulated industry to a competitive, market–based environment where utility and non-utility generating companies, or GENCOs, would compete for customers, or so FERC believed.

Creating ISOs and functional unbundling requirements would restructure the industry by separating the vertically integrated utilities' ties between generation and transmission. Removing this means of discrimination ensured open access to transmission, promoting competition in the generation sector. FERC called for leaving the transmission sector regulated because of its natural monopoly status and economies of scale. Meanwhile, plans also called for deregulating the distribution sector on a by-state basis called retail choice where consumers would individually select their power provider.

FERC outlined the second part of the plan in Order No. 889. This rule set out to correct insufficient sharing of transmission system information. It required utilities to create Open Access Same-time Information Systems with transmission system information posted on Internet sites and available for all interested parties at the same time.

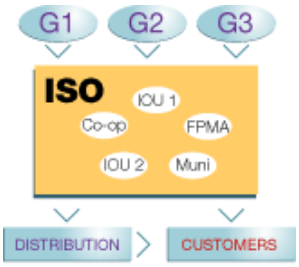
Order No. 888 also outlined 11 ISO operating principles and guidelines criteria. Primary ISO responsibilities were to include:

- Operating the transmission system (which was still to be owned by transmission utilities) within a control area
- Creating and operating an OASIS site
- Dispatching queing and generation
- Operating the control area's power markets for generation and transmission

Order No. 888 mandated that jurisdictional utilities hand over control of their transmission facilities to an ISO, but these same facilities were still to be owned by the member utilities. Proposed ISOs had to prove they met these criteria to receive FERC approval.

Under Order No. 888, FERC asserted it had jurisdictional authority over retail transmission service, specifically wholesale and unbundled transmission service as defined within Order No. 888. The state of New York and eight others disagreed and filed suit. The case went before the U.S. Supreme Court. On March 4, 2002, the U.S. Supreme Court ruled in FERC's favor. In dissenting remarks, three justices stated they believed FERC should also have jurisdictional authority over bundled transmission.

ISOs proposed by the investor-owned utilities in response to Order No. 888 were typically organized along state boundaries or slightly larger areas. FERC also called for ISOs to be operating by July 9, 1996. This proved to be a very short timeframe for such a complicated task.



ISO Responsibilities

Transmission sector

- **State-based Control Area** (typically)
- System **Operations,** OASIS, Market
- Non-profit, operating costs only

Generation sector

- ISO **dispatches** generation
- Operates market and queue

Order No. 888 spawns proposed ISOs

FERC rules adapt to industry restructuring, deregulation

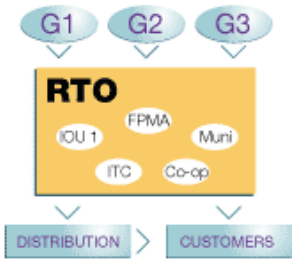
Three years after the 1996 Order No. 888 was issued, the Federal Energy Regulatory Commission determined, via GENCO reports, that substantial barriers to functional deregulation still existed and needed to be corrected. Order No. 888 had two primary shortcomings: inefficient operation and expansion of the transmission system and continued transmission system access discrimination.

FERC Order No. 2000

To address these shortcomings, in December 1999 FERC issued Order No. 2000, its second attempt at wide-sweeping changes in how the electric utility industry operated. FERC anticipated many benefits including lower electricity prices plus a creation of lighter-handed regulation.

FERC believed that transmission would be more effective and efficient if it were planned and operated on a regional, multi-state scale. All states within an interconnection are impacted by disturbances within it, as seen during the Western Interconnection disturbances in Summer 1996—and more recently the Northeast blackout in August 2003. FERC asserted in 1999 that ISOs should be larger, due in part to the 1996 disturbances. To that end, it called for regional transmission organizations.

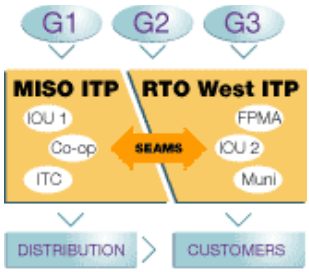
Under FERC's plan, RTOs would be larger, appropriately sized versions of their ISO predecessors with the same responsibilities. An RTO would operate the transmission facilities within it's geographical scope, the control area. RTO guidelines would end transmission system access discrimination, FERC believed.



RTO Responsibilities

Transmission sector
- Essentially Replaces ISO
- Multi-state control area
- Operates system, OASIS, market
- Facilities owned by TOs
- Regulated profit or nonprofit

Generation sector
- Essentially same as ISO



Transmission sector
- Essentially Replaces RTO
- "Effectively" larger RTO
- Operates system, OASIS, market
- Facilities owned by TOs
- Market monitoring, adequacy

Generation sector
- Essentially same as RTOs

RTOs, ISOs differ

The RTO operating guidelines, or criteria, included four characteristics and eight functions. The four characteristics are:

- Independence
- Geographic scope and regional configuration
- Operational authority
- Short-term reliability

The RTO functions are:

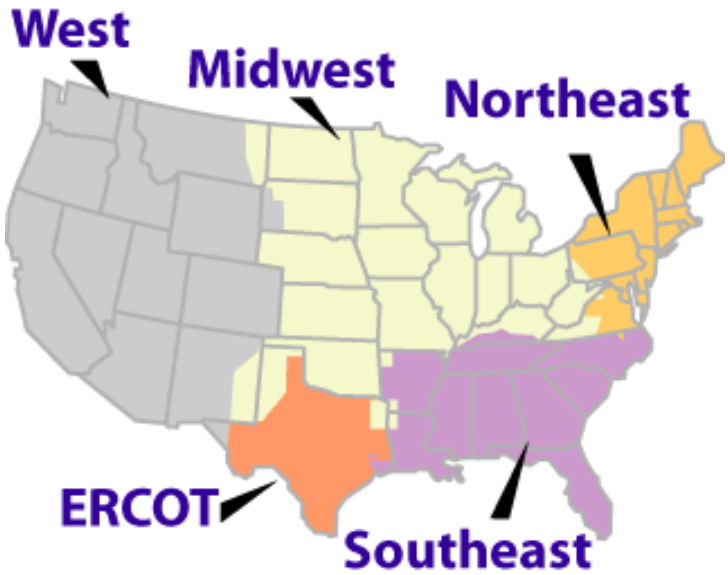
- Tariff administration and design
- Congestion management
- Parallel path flow
- Ancillary services
- OASIS calculations
- Market monitoring
- Planning and expansion
- Interregional coordination

FERC required ISOs already in operation to prove they met these criteria to gain approval as an RTO.

According to FERC, differences exist between RTOs and ISOs. RTOs could be non-profit organizations, previously organized as ISOs or they could be Transcos—regulated for-profit organizations. FERC encouraged transmission owners to voluntarily hand over control of their facilities to an RTO of which they were a member.

Around this time, independent transmission companies began to appear on the American scene. These new firms did not own generation or distribution assets.

FERC starts with 5 RTOs



FERC specified that ITCs could participate as RTO members or form their own RTOs. FERC called for the resulting RTOs to be operating by Dec. 15, 2001.

After Order No. 2000, proposed RTOs were typically geographically larger than their ISO predecessors, but were still not as large as FERC believed necessary to be truly effective.

FERC originally envisioned five RTOs for the entire U.S. transmission system—Northeast, Southeast, Midwest, Texas and the entire Western Interconnection. This did not occur. Instead 13 separate, non-continuous RTOs were initially proposed, each with its own unique transmission and wholesale market rules.

The result was a problem, which occurred at the boundaries of neighboring RTOs. Due to their different operating rules, neighboring systems had difficulties resolving schedules and payments for electrical service between RTOs. These seams issues allowed continued transmission access discrimination and hindered restructuring, as reported to FERC by GENCOS.

Inadequate RTO geographical scope continued to plague FERC's restructuring efforts. To correct this, FERC issued the Standard Market Design Notice of Proposed Rulemaking on July 31, 2002.

SMD to eliminate seams

The primary goal of SMD, later renamed the wholesale power market platform, was to eliminate seam problems by standardizing the way generation and transmission markets operate. This design would "effectively" create the FERC-preferred larger RTOs by standardizing how RTOs would function. Many believed SMD would improve market oversight, promote transmission planning and expansion, lower the cost of electricity and create a framework for cooperative state and Federal regulation.

To accomplish this goal, SMD provisions called for the creation of independent transmission providers to replace RTOs. ITPs would retain many RTO responsibilities plus others to accomplish the primary goal of SMD. Under the SMD proposal, investor-owned utilities had to file new transmission tariffs. Community, co-op-owned and Federal utilities would follow reciprocity guidelines established under Order No. 888. Locational marginal pricing and congestion revenue rights were introduced to address transmission pricing policies for transmission congestion. Under SMD, FERC asserted it had jurisdictional authority over bundled transmission. Finally, FERC proposed to develop resource adequacy guidelines and a regional planning process to sustain a viable electrical power system.

Some states and utilities in the Northeast, Midwest and Texas, approved of SMD while many in the Southeast and West did not. SMD opponents voiced strong opposition. Their concerns included: jurisdictional overreach by FERC; destabilizing economic effects (cost shifting) and participant funding; incomplete operational specifics of how the markets will work; and failure to acknowledge regional differences.

Congress became involved in the debate over SMD, via the comprehensive energy bill. As a compromise, FERC issued a white paper on April 28, 2003, addressing issues from the initial SMD ruling.

Key features outlined in the white paper include:

- The formation of RTOs
- Ensuring that all independent transmission organizations have sound wholesale market rules
- Varying implementation schedules depending on regional needs and regional difference.

According to FERC, its proposal has taken into consideration the experiences in this country and abroad in electric market design, including:

- The effects of supply shortages
- Demand that does not respond to high prices
- Lack of price transparency in the marketplace
- The importance of market monitoring and market power mitigation
- Industry continues functioning, future unknown

Throughout the years of restructuring efforts, electric utilities have kept the nation's electric system functioning and America running. Transmission infrastructure investment continues to decline, due to delays in creating a final restructuring plan. In its 2003 reliability assessment, NERC reported that system capacity appears to be adequate for the time being.

Today, the U.S. electric utility industry is mired in politics and regional debates, yet the demands on the interconnected power grid continue to grow. Our nation depends on a viable electric utility industry and bulk power system for its security, economy and way of life. While these debates and political discussions continue, the viability of our nation's bulk power system, upon which we depend, hangs in the balance.

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12/03