



**PDHonline Course E302 (3 PDH)**

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# **Electric Transmission Grid**

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# Electrical Transmission Grid

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## Introduction

In the past 30 years electricity use has doubled as a percentage of the total energy usage in the United States. The electric power industry is vital to the efficient operation of the sophisticated information based economy. It is one of the last major regulated industries and it is slowly moving toward becoming a competitive market.

There are over 3,000 utilities in the U.S. from very small municipal systems to large systems with several million customers. These utilities include investor owned companies, cooperatively owned companies, and publicly owned systems. The electric power industry has traditionally been vertically integrated where, for the most part, the same company owned the generation, transmission, and distribution systems that served a given load center. The traditional view is that the electric power industry is a natural monopoly where least costs are obtained by operating large centralized generating plants integrated with the transmission and distribution systems. Since the early 1990's the generation component of the industry has become more of a competitive market as independent power producers (IPP's) enter the market.

The purpose of the transmission system is to provide a path to transport power from the generating plants to the local distribution systems. With the advent of IPP's, who do not necessarily locate their plants near the intended load centers, the transmission system is facing new competitive pressures. Even with competitive generation and transmission becoming more competitive, the local distribution systems will likely continue as natural monopolies into the foreseeable future.

This course is an overview of the electric power industry. It includes a brief history of the industry, a description of the different participants in the market, a review of significant legislation affecting the industry, and a detailed description of how the electric transmission grid operates. We will begin with a look at the overall structure of the industry.

## I. Structure of the Electric Power Industry

The three major components of an electric power system: generation, transmission, and distribution are shown in Figure 1. Generation is the production of electrical energy from other energy sources. Transmission is the high-voltage transportation system to deliver power from the generators to communities. The distribution system converts the high-voltage transmission supply to lower voltages for distribution throughout communities and neighborhoods. The final portion of the distribution system further reduces the voltage to appropriate levels for use in a home or business. In this section we will take a brief look at each component in an electric power system.

### Electric Power System Components

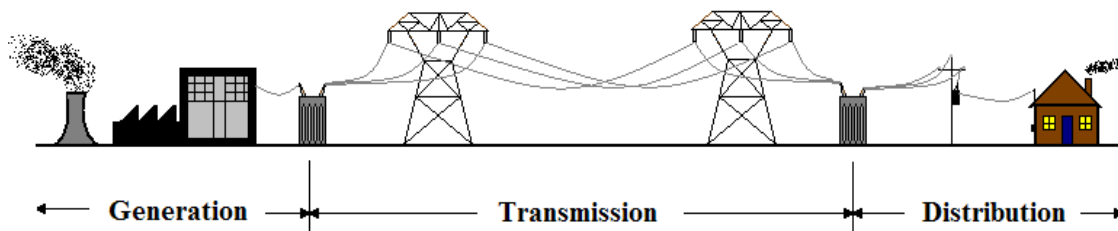


Figure 1

From a cost perspective, generation is the largest cost component of the industry followed by distribution, and transmission is actually a small component of the overall cost structure. See Figure 2 for a breakdown of the investment in the electric power industry.

### Electric Power Industry Cost Breakdown

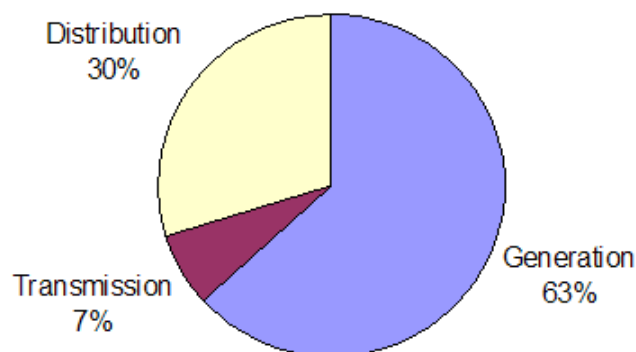
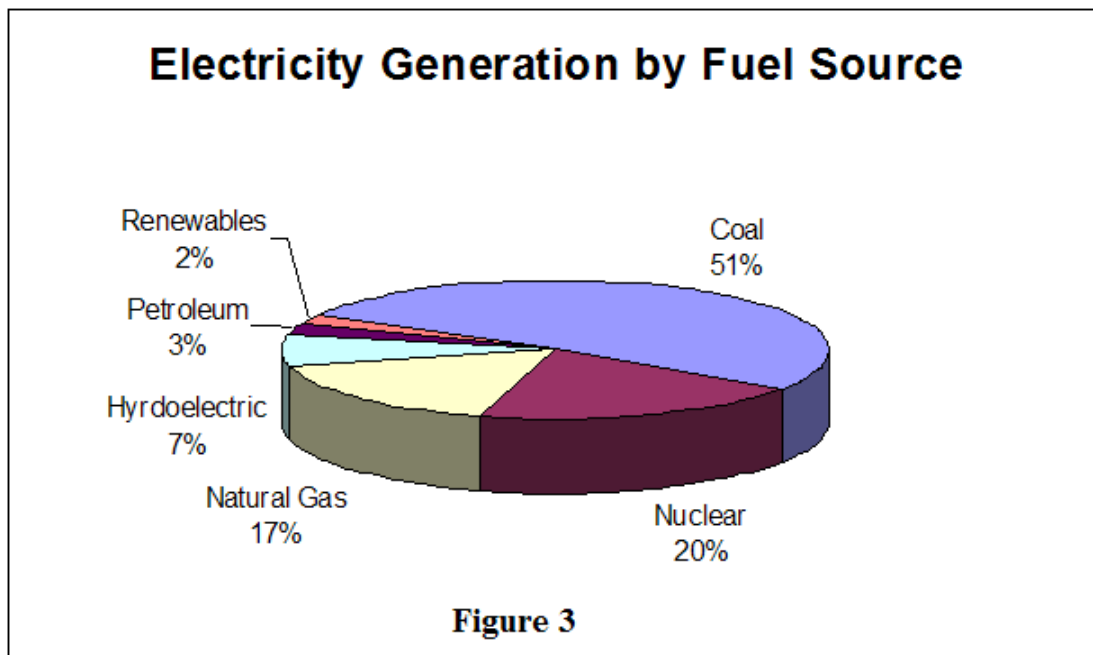


Figure 2

## Generation

The generation fleet in the U.S. consists of over 10,000 power plants. They are classified by the type of prime mover, the fuel source, and the application. The prime mover is the machine that actually drives the generator and may be an internal combustion engine, turbine, or water wheel. The fuel source can be fossil fuels, such as diesel fuel, natural gas, propane, or nuclear fusion, water, wind, or even sunlight. The generator application is categorized into one of three load types: base, intermediate, and peaking. Base load units are generally very large units that generate electric energy relatively cheaply, such as nuclear or coal plants, and are designed to run continuously at a constant output. Peaking units use more expensive fuels such as natural gas and diesel fuel and are used to cover the short time peak load periods during a day. Hydroelectric plants are normally categorized as peaking plants due to the scarcity of water in many parts of the country. The output of peaking units can be varied relatively easily to meet the peak load. They are usually the cheapest units to build and can be put in service quickly. Intermediate plants cover the loads above the base load units and below the peaking units. Intermediate plants are predominately coal and natural gas combined cycle units.

The predominate fuel source in the U.S. is coal followed by nuclear and natural gas. See the chart in Figure 3 for a breakdown of the fuel types.



As you can see, coal makes up slightly over 50% of the fuel mix and nuclear is a distant second with 20% of the market. Renewable fuels are about 2% of the mix. Due to the difficulty in building coal plants - which is because of the clean air rules - nuclear plants are poised to gain a much larger share of the market in the future. Likewise, due to rising energy costs, renewable sources are expected to gain a small amount of market share.

Coal plants are known as *steam units* because the coal is burned in a boiler to generate steam that then drives a steam turbine. Nuclear plants are also steam units where nuclear fission generates heat to make steam to turn the turbine. These processes generate waste heat that must be cooled using cooling towers. Coal and other fossil fuel source plants require expensive pollution control equipment to capture sulfur dioxide (SO<sub>2</sub>), nitrogen oxide (NO<sub>x</sub>), and carbon dioxide (CO<sub>2</sub>). Coal fired plants generate significantly more SO<sub>2</sub> than other fossil fuel sources. In fact, the amount of SO<sub>2</sub> in the coal varies depending on where the coal is mined. For instance, Eastern Appalachian coal has more SO<sub>2</sub> than Western coal.

Gas turbines and internal combustion engines are examples of *gas units*. Instead of steam, the units use hot gases from burning fossil fuels to drive the turbine. Gas units are cheaper to build than steam units but they are less efficient. One form of gas unit is a *combined-cycle unit*. Combined-cycle units have a gas turbine to generate power, and then the waste heat from the unit is fed into a steam turbine to generate additional electric power. In the 1990's natural gas prices made these units economical for intermediate plants, but recent gas prices have made the economics of combined cycle gas units less attractive.

*Cogeneration unit* is a term used to describe a generator that is also used for another purpose. For instance, a sawmill may use waste wood chips to fire a boiler to generate steam to produce electricity. Furthermore, the waste heat from the generator may be used to provide space heating, etc. Cogeneration units are found in manufacturing plants and the term, cogeneration, comes from the fact that the steam used to fire the boiler is also being used for another application. There are two types of cogeneration units, bottom-cycling and top-cycling. With *bottom-cycling units*, the manufacturing plant generates high quality steam for its industrial process and the waste is then used to drive the turbine generator. With a *top-cycling unit*, the steam is first used to produce electricity and the waste steam is then used in the manufacturing process.

*Kinetic energy units* use water or wind to turn turbines to produce electricity. Most hydroelectric units are based on impounding large quantities of water. Since water is a scarce resource in many parts of the country, it is only feasible to run hydroelectric units for a few peak hours per day. There are some new, small, efficient, "run-of-the-river" hydroelectric units that do not require impoundments, but these units tend to be very small and not applicable to large scale generation. Wind turbines use an inexhaustible resource, wind, to generate electricity. These units are only feasible where significant wind sources are available, and community support is often difficult to obtain due to the impact the units have on the community's "view shed". Solar units are another renewable generating source that is gaining popularity. These units are best suited for small, end-use applications such as roof top units to serve a single dwelling. Both wind and solar units suffer from an intermittent fuel source.

The choice of a fuel source is largely dictated by the availability of natural resources in the area. The Pacific Northwest has a large base of hydroelectric plants because of the availability of water resources. The Eastern states are heavily dependent on coal because of the abundance of coal in the Appalachians. Oil-rich states such as Texas, Louisiana, and Oklahoma, use a lot of natural gas to generate power. Florida is a major natural gas user because of the expense of transporting coal to the State.

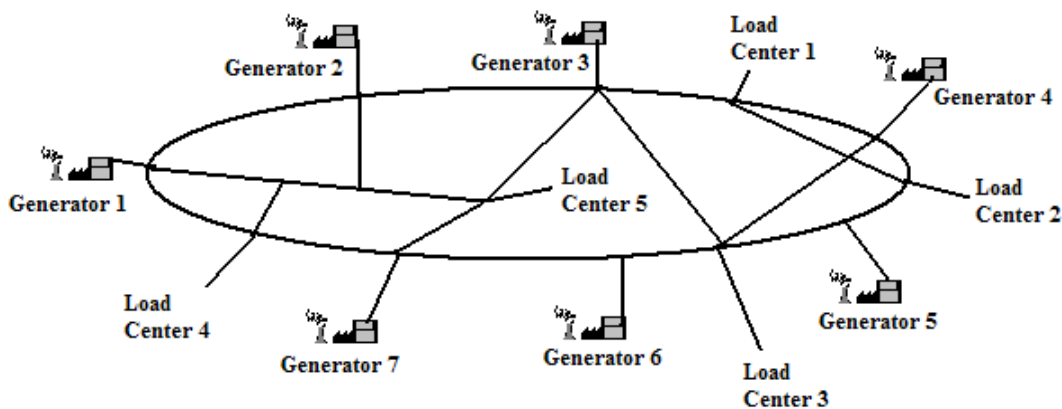
## Transmission

There are over 150,000 miles of transmission lines in the U.S. that deliver power from the generators to the load centers. Not only are transmission lines used to deliver power to the load centers, they are also used to provide interconnections with other utilities for reliability and economic load transfers.

Unlike the simple diagram in Figure 1 the transmission system is truly a “grid” where many power plants are connected to many transmission lines, which “pools” all generation resources into one common grid. The distribution system connects to this grid and draws power from that point on the grid. This interconnected grid concept results in an extremely reliable power system since the loss of any one power plant does not shut down the flow of power into the grid. See Figure 4 for a simple schematic view of the electric power grid.

As you can see in Figure 4 there are many paths from the generator to the load centers, and the loss of any one path from a generator, or loss of any one generator, would not cause a loss of power at the load center.

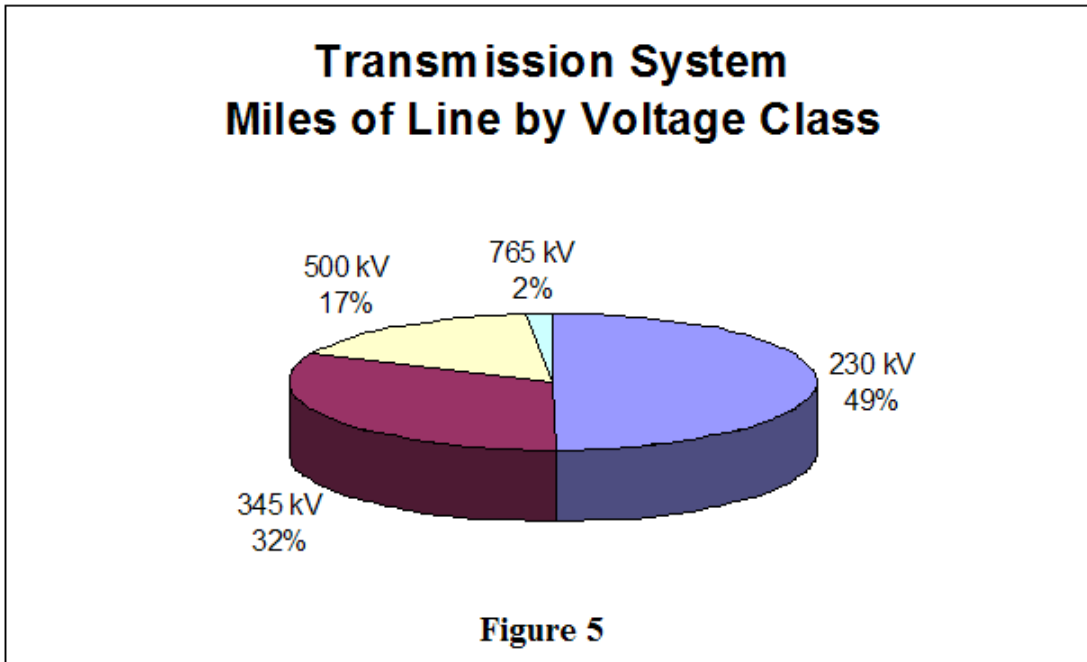
### Transmission Grid Structure



**Figure 4**

Transmission systems utilize high voltage, alternating current (AC) systems to promote the transportation of large amounts of power and to reduce the  $I^2R$ , or heat losses, due to the resistance in the power lines. Although there is not an exact definition of transmission voltages, it is generally assumed that anything over 138 kV is transmission. Another class of transmission, called sub-transmission, is in the range of 46 kV to 115 kV and is used to deliver power in a community to different distribution substation sites. There is a small amount, less than 3%, of the transmission system that operates on direct current (DC).

See Figure 5 for a breakdown of miles of transmission by voltage class. The 230 kV voltage class represents 49% of the market. Next is 345 kV, which has 32% of the market. 765 kV has the smallest share at only 2% of the market.



Alternating current (AC) is the preferred method of transmitting power because it is easy to convert from one voltage to another. Direct current (DC) is more difficult to convert to other voltages, and the cost to convert a DC voltage from one level to another is significantly higher than when using AC power. The benefit of DC power is that it can be used to efficiently deliver large amounts of power over great distances. Another benefit is that DC power systems are not frequency dependent and can be used to interconnect dissimilar AC systems.

### **Distribution**

Once the transmission system has delivered the power to a community or region, the distribution system takes over to deliver the power to the ultimate consumer. From the high voltage transmission system, the voltage is stepped down to a distribution voltage (usually 15, 25, or 35 kV) and distributed using overhead and underground distribution lines to neighborhoods. At the end user, the voltage must again be stepped down to an end user level (120/240-volts for a residential application).

The distribution system is a natural monopoly and providing duplicate service for distribution is impractical at this time. As a monopoly the distribution system is regulated either by a public utility commission, a city council, or a committee of members for member-owned cooperatives.

One issue facing distribution systems is distributed generation, which is where many small independent generating systems are connected to the distribution utility system. These systems, typically fuel cells, photovoltaic, wind, and run-of-the-river hydroelectric systems, will most



likely not impact the transmission system, but they do create operational problems for the distribution system from load flow, metering, and worker safety.

## II. An Overview of the Industry

For an overview of the electric power industry we will review the history of the industry, discuss the various participants that operate in the market, and look at the regulators who impact how the industry operates.

### A Brief History

In 1882, Thomas Edison began operation of the first commercial generating station in the U.S. His Pearl Street station was located in New York City and provided 59 customers with 110-volt DC electric lighting. Lighting was the only load served initially. By today's standards the plant was terribly inefficient with a heat rate of 138,000 Btu/kWh. In 1896, George Westinghouse built the first hydroelectric plant at Niagara Falls and generated AC electric current, which he transmitted to Buffalo, New York for consumption. This was the use of a remote generating plant and the conversion of the power to a higher voltage (11,000-volts) for transmission and then stepping the power back down to a useable level for consumption at the distant load center. The 1890's saw the rapid expansion of small independent power systems in large central cities areas. In 1892 Samuel Insull took over as president of a small utility in Chicago and began buying many small electric plants in the city and is credited with starting the concept of large holding companies for utility operations. His company, Chicago Edison, later became Commonwealth Edison. Publicly owned municipal power systems began appearing during this time, and by the end of the century they were about 8% of the market. By the end of the century the efficiency of power plants had improved to around 92,000 Btu's/kWh.

From the turn of the century (1900) until 1930, the industry saw the consolidation of the many small electric systems that had begun the industry. Holding companies were formed where owners held controlling interest in numerous small electric systems. In fact, by 1920, fewer than 20 holding companies controlled over 75% of the generation in the U.S. In some cases the operators of the holding companies manipulated the market by shifting costs among their various utilities. Recognizing that the electric utility industry was a natural monopoly, states began establishing public service commissions to franchise territories and to regulate the rates of the utilities. By 1930, the heat rate efficiency of the nation's generating capacity was approaching 20,000 Btu's/kWh. In 1900, utilities were transmitting power at 44,000-volts and by 1920, voltages were 115,000-volts.

The period from 1930 until 1950 saw a larger Federal role in the industry from both a regulation standpoint and as a market participant. In spite of the formation of public service commissions by the states, private utilities were abusing their monopolistic control of the market since many of the large holding companies involved multi-state systems. In 1935, the Public Utility Holding Company Act (PUHCA) was established to regulate the interstate commerce of the electric power industry. By 1930, almost 80% of urban dwellings had electric service available, but only 10% of the rural areas were served because of the high cost of serving isolated customers. To foster rural development, the Rural Electrification Act (REA) of 1936 established a government agency to encourage the development of rural electric cooperatives. Cooperatives are not-for-profit, member owned entities with the purpose of promoting economic development in rural areas. The REA assisted the cooperatives by offering subsidized loans and technical expertise.

Transmission voltages also increased during this time to about 230,000-volts. The Federal government also entered the market as a participant by developing large hydroelectric plants such as the Hoover Dam and the Grand Coulee Dam. Federally owned utilities such as the Bonneville Power Administration (BPA), Tennessee Valley Authority (TVA), Southwestern Power Administration (SWPA), and the Southeastern Power Administration (SEPA) were begun. By 1950, the average heat rate had improved to less than 15,000 BTU's/kWh.

The 1950's were a period of unparalleled prosperity in the electric power industry. The Nation's demand for electricity continued to increase and the first commercial nuclear plant began operation in Shippingport, Pennsylvania, in 1957. With few practical locations left to develop large scale hydroelectric plants, the expansion of Federal power slowed.

During the 1960's the first signs of trouble appeared in the electric power industry. While efficiency gains continued, the rate of these efficiency gains declined. However, by 1970 heat rates were approaching 10,000 Btu's/kWh. With slowing efficiency gains, production costs increased, and capital additions for new generating plants and transmission and distribution infrastructure caused prices to rise in real terms. Environmental concerns about the impact of coal plant emissions began to impact the industry. The first major disturbance to hit the industry occurred in 1965 with the blackout in the northeast. It was followed by a second major blackout in the northeast in 1967.

The 1970's hit the electric power industry very hard. First, the Clean Air Act of 1970 and subsequent amendments required utilities to install expensive equipment to reduce pollutants entering the atmosphere from plant stacks. The energy crisis of 1973 caused prices to rise for utilities and created a nationwide interest in energy conservation. The cost of capital additions became very expensive due to rising interest rates and high inflation. By the late 1970's capital additions were exceeding anticipated demand and the last nuclear plant of the 20<sup>th</sup> century was ordered in 1978. Congress enacted the Public Utility Regulatory Policies Act (PURPA) in 1978, which, among other things, required regulated utilities to purchase power from certain independent power producers.

Slow economic growth in the early 1980's along with a surplus of generation from the 1970's building era caused electric utility prices to rise. To further compound the problem, new plants were reaching a technological limit where the heat rates remained at about the same level as 1970. Even today, heat rates have not improved significantly from the 1970 average of 10,000 Btu's/kWh.

The industry enjoyed a relatively calm period during the 1990's with demands increasing to fully utilize the existing capacity. Prices stabilized or even declined during this period. The generation markets were essentially deregulated in the 1990's and non-utility generators began selling power on the open market. With stringent clean air rules making new coal plant construction prohibitively expensive and natural gas prices low, many new natural gas plants were built. Both peaking combustion turbines and combined cycle intermediate load plants were built during the 1990's. These plants were economical to build and operate, which further stabilized utility prices.

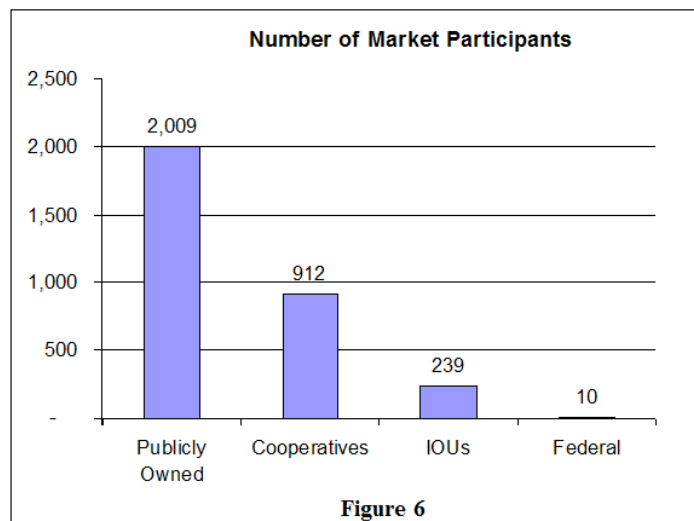
By 2000, any excess base capacity in the country was fully utilized and rising natural gas prices made combined cycle plants less attractive. In the first decade of the 21<sup>st</sup> century the U.S. finds itself in a position of needing large quantities of base load capacity. Coal and nuclear are the natural choices for base load capacity, but coal prices have risen dramatically due to the world demand for steel (coking coal, which is used in steel production had been sold to utilities for electricity generation due to the weak steel markets in the 1980's and 1990's.) Further concerns about future clean air rules have made the decision to build coal plants more difficult for utilities. Even with concerns about future disposal of spent uranium, many utilities are now looking at nuclear for their next base load plants.

### Market Participants

There are over 3,000 utilities in the U.S. composed of privately held utilities, called Investor Owned Utilities or IOU's; publicly owned utilities, such as municipal electric systems; cooperatives, which are member-owned utilities; and federally owned utilities such as BPA.

Figure 6 is a breakdown of the number of utilities by type in the U.S. As you can see, publicly owned utilities make up the largest share of the market based on number of participants at 2,009. Cooperatives are the next most numerous at 912 followed by IOUs at 239, and then Federal utilities at 10.

While *Investor Owned Utilities* (IOU's) represent only about 8% of the total number of utilities, they serve the largest market share. IOU's have about 75% of the total market share in both generation share and electric sales. Their customer density averages 35 customers per mile of line, which is surpassed only by the municipal electric systems. As an investor-owned company the purpose of an IOU is to generate profits for their investors. To protect the end-use consumer, IOU's are regulated by state public service commissions who grant service monopolies, set rates, terms of service, and handle consumer complaints. Just about all IOU's provide all three functions of a utility: generation, transmission, and distribution. In addition, they frequently have unregulated divisions that sell generation into the competitive generation market. The Southern Company ([www.southerncompany.com](http://www.southerncompany.com)) is an example of a large IOU.



Publicly owned electric utilities are not-for-profit local government agencies that were established to provide electric service in their communities. The most common form of a publicly owned electric utility is a municipal electric system. These systems are owned by the city they serve and are often the local gas distributor and sometimes the local water provider.

Memphis Light, Gas and Water ([www.mlwg.com](http://www.mlwg.com)) is an example of a municipal electric system. Municipal systems are generally under the direction of a city manager and city council and any profits from the operation are returned to the general treasury of the city. They are not under the jurisdiction of a public service commission since the users have control via their elected officials. Municipals serve about 15% of the market. Municipals have the highest customer density since they generally serve inside the city limits of their municipality. The typical customer density for a municipal is 47 customers per mile of line. Most municipal systems buy their power from Federal generators or IOU's and simply serve as the local distribution company.

Formed in the late 1930's as a way to electrify rural America, cooperatives now serve the majority of the land mass in the U.S., but they have only about 9% of the market revenue. Figure 7 shows the breakdown of market share by type utility. Due to their mostly rural nature, cooperatives have the poorest customer density with only about 7 customers per mile of line.

Due to their poor customer density, the Federal government provides loan guarantees to assist the utilities with obtaining low interest loans for capital expansion projects. Cooperatives are member-owned utilities and their function is to provide electric service to their members and assist their communities with economic development. The members of a cooperative elect a board of directors to oversee the utility and they hire a manager to run the cooperative. Very few cooperatives are under the control of a state public service commission since the members have democratic control of the company. The cooperatives have a nationwide association, the National Rural Electric Cooperative Association ([www.nreca.org](http://www.nreca.org)) that has more information about the cooperatives in the U.S. Electric cooperatives are typically just local distribution companies like a municipal electric system; however, in many states the cooperatives have joined together and formed their own generation and transmission cooperatives, called G&T's.

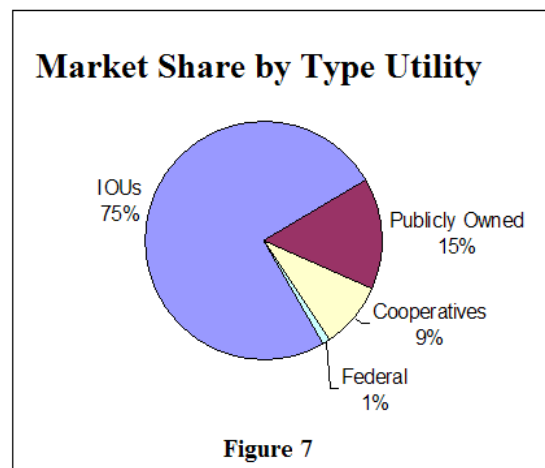


Figure 7

There are only 10 *Federal electric utilities* in the U.S. These facilities are predominately generation and transmission companies and serve very few end-use customers. In fact, looking at Figure 7 we see that the Federal utilities have less than 1% of the market share. The purpose of the Federal utilities is to sell power to preference customers and to recover their costs of operation. Preference customers are publicly owned power systems and cooperatives. Most of the Federal plants are hydroelectric plants that were initially built for flood control and irrigation. However, some Federal utilities, such as TVA, operate coal and nuclear plants.

An entire separate class of electricity provider is the non-utility generator (NUG). Non-utility generators include cogenerators and qualifying facilities, independent power producers, and exempt wholesale generators.

Cogenerators are typically manufacturing plants that must make steam for their manufacturing operation and can also use the steam to generate electricity. In some cases a byproduct of the

manufacturing process, such as waste wood chips from a lumber mill may be burned to produce electricity to run the plant. Excess power is sold into the market. Some cogeneration facilities can become qualifying facilities by meeting certain requirements dictated by FERC under the PURPA rules.

Independent power producers (IPP's) generate power with renewable resources such as small hydroelectric plants or wind farms and they sale into the wholesale market.

Exempt wholesale generators (EWG's) are non-regulated electric generation facilities. EWG's can be owned by a regulated utility, but their operation is an unregulated venture in the competitive wholesale generation market. The term EWG comes from the fact that if a regulated utility wanted to own a non-regulated competitive market generating company they had to be exempted from certain aspects of the PUHCA laws.

## Regulators

Regulation of the electric utility industry is done primarily by state public service commissions and by the Federal Energy Regulatory Commission (FERC) at the national level. The National Electric Reliability Council (NERC) is presently a voluntary regulator of the bulk transmission system, but may soon have statutory authority to mandate certain reliability standards.

The state *public service commissions* (PSC's), sometimes called public utility commissions (PUC's), were the first attempt to regulate the electric utility industry. The earliest PSC's were formed around 1907. State PSC members are elected by the citizens of the state and in some states the PSC members are appointed by the governor or legislature. The purpose of the PSC is to establish monopoly service territories, set rates for retail customers, determine an allowable return on investment for the investors, set service standards, and generally looks out for the consumer's interest. The PSC has the authority to certify new generation and transmission facilities and can decide whether to include these investments into the rate base, or if the PSC deems the investments imprudent, they may exclude the investments, requiring the investors to pay. The National Association of Regulatory Utility Commissioners ([www.NARUC.org](http://www.NARUC.org)) has more information about state utility regulation.

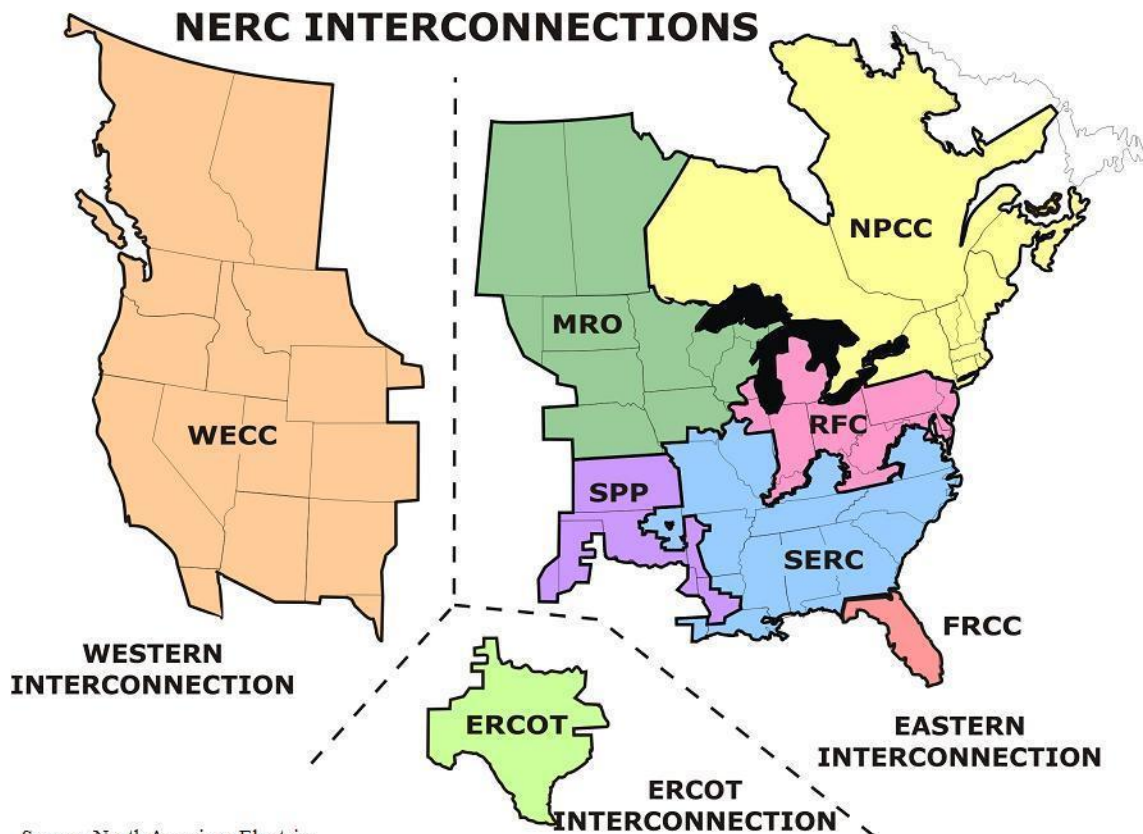
The Federal Energy Regulatory Commission (FERC) is an outgrowth of the Federal Power Commission, which Congress established in 1920. The purpose of FERC is to regulate the interstate commerce of electric transmission, including rates, as well as regulate the wholesale sale of electricity. FERC is governed by a five-member board that is appointed by the president to five-year terms. The board is autonomous and its decisions are independent from any branch of the government, even though the FERC is organized as a part of the Department of Energy. Since the late 1970's FERC has been pushing for deregulation of the wholesale electric markets. Several FERC orders (to be discussed in Section IV) have been significant in pushing for deregulation. More information about FERC can be found at [www.ferc.gov](http://www.ferc.gov).

The North American Electric Reliability Council (NERC) was formed by the industry as a voluntary organization to ensure that the bulk power system in the U.S. is reliable, adequate, and secure. It was formed in 1968 to allay concerns about the two major blackouts in the Northeast

in 1965 and 1967. NERC is an independent, not-for-profit organization that represents virtually all of the electric suppliers in this country. All segments of the industry are represented from IOU's, public power, cooperatives, NUG's, Federal power, and even end-users. NERC has operated on the principle of "relying on reciprocity and mutual self-interest", which is basically the Golden Rule – do unto others as you would have them do unto you. The organization sets standards for reliable operation of the bulk electric system and monitors and assesses compliance with its reliability standards. The North American Electric Reliability Council, NERC, is divided into eight reliability regions (there were formally ten regions, but three consolidated in the Northeast), which provide regional oversight on the operation of the grid. The reliability regions are,

1. ERCOT – Electric Reliability Council of Texas
2. FRCC – Florida Reliability Coordinating Council
3. MRO – Midwest Reliability Organization
4. NPCC – Northeast Power Coordinating Council
5. RFC – ReliabilityFirst Corporation
6. SERC – Southeastern Electric Reliability Council
7. SPP – Southwest Power Pool
8. WSCC – Western Systems Coordinating Council

See Figure 8 for a map of the reliability region areas.



Source: North American Electric Reliability Council

Figure 8

Operating NERC as a voluntary organization worked well in a conservative, monopolistic atmosphere of the past. However, after the 2003 blackout in the Northeast, many are saying that a voluntary organization can no longer be effective in a competitive marketplace, and we must have mandated reliability standards.



### III. Transmission System Operational Characteristics

A major decision that was made during the infancy of the electric utility industry was to interconnect systems for reliability. As we have already seen, interconnecting systems provides backup for loss of generation or in some cases loss of transmission. By interconnecting the entire grid it operates as one giant machine, and a disturbance along any path of the grid may have consequences in other areas.

Another problem with the grid interconnection of an AC electric system is that it is very difficult to control the paths of the load flows. From a study of basic electricity we know that electricity follows the path of least resistance. Look at Figure 9, even though utility “A” has a commitment to sell power to Utility “B” across transmission line “D”, the power may prefer to flow across transmission lines “E” and “F”, potentially using all of the capacity of “E” and “F”. If transmission lines “E” and “F” are owned by another utility (utility “C” in the diagram), then utility “C” may be unable to make economic sales of power to other areas because of the “loop flows” caused by utility “A”.

#### Transmission Line Loop Flows

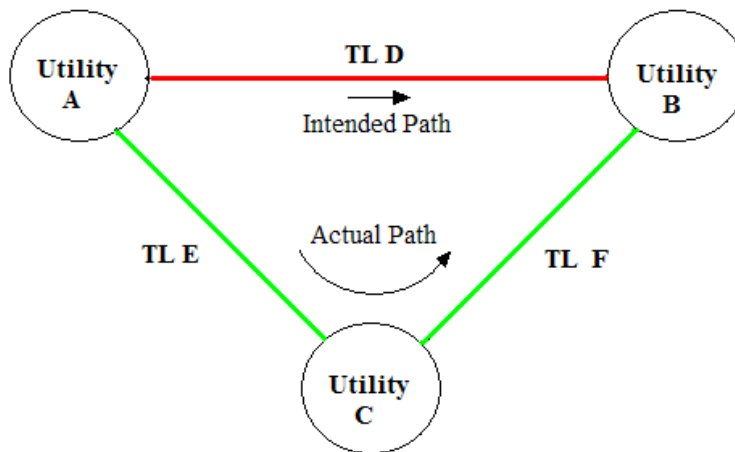


Figure 9

#### Interconnects

The electric system in the U.S. is divided into three networks or power grids. All utilities within these regions are connected to the grid. The grids are: The Eastern Interconnect, the Western Interconnect, and the Texas Interconnect. The Eastern Interconnect includes all electric systems in the eastern two-thirds of the U.S. and a portion of Canada. The Western Interconnect includes the areas west of the Rocky Mountains and the western portions of Canada. In North America there is also a fourth interconnect known as the Quebec Interconnect in far eastern Canada and the maritime providences. See Figure 8 on page 15 for a layout of the interconnections.

Except for a few DC interconnects and other special tie points, the interconnects are not connected to each other. Therefore, power does not flow from the Eastern interconnect to the Western interconnect or to Texas. Likewise, Texas is an electrical island from the rest of the country.

## Control Areas

To ensure compliance with NERC guidelines, utilities operate in Control Areas. Because electricity cannot be stored and generator outputs must be coordinated with the demand for electricity almost instantaneously, control areas are used to match the generation output with the demand for electricity. There are over 100 control areas operating in the U.S. The control area operators have numerous performance standards that they must meet to ensure the safe and reliable operation of the power grids.

## Performance Standards

NERC publishes a guide to performance standards for utility operators called the Reliability Standards for the bulk electric systems of North America. This document defines the performance standards for all utilities to follow. The performance standards and the calculations supporting the standards are complex. The following is just a brief overview of a few of the common standards.

First, we need to review a few terms. The *Area Control Error*, or ACE, is the instantaneous difference between a balancing authority's net actual interchange and its scheduled interchange, taking into account the effect of frequency bias. *Frequency bias* is a value that represents the balancing authority's response to interconnection frequency error and it is expressed in MW per 0.1 Hz. The balancing authority is, in most cases, the Control Area.

The first standard, and one of the easiest to meet, is *Control Performance Standard 1*, or CPS1. CPS1 is a 12-month average of the balancing authority's Area Control Error (ACE). NERC says that the balancing authority must have a CPS1 of 100%.

The second control performance standard is *Control Performance Standard 2*, or CPS2. CPS2 requires that the balancing authority operate to keep its average ACE for at least 90% of all of the 10-minute periods in a given month to within a specific limit known as  $L_{10}$ .

The *Disturbance Control Standard* (DCS) makes sure that the utility has adequate contingency reserves to balance resources with demand and return to the interconnection frequency with a specified time period. NERC says that the balancing authority may use generation, controllable loads, or may adjust interchange schedules to meet the contingency reserve requirement.

While not a performance standard, it is probably appropriate to mention Available Transfer Capability (ATC) and Transmission Loading Relief, or TLR, procedures. *Available Transfer Capability* (ATC) is a measure of the transfer capability remaining in the transmission network to reliably support wholesale transactions. A Transmission Load Relief (TLR) is a method to

manage congestion by curtailing some requests for transmission access when the system is in danger of becoming overloaded. When a TLR is in effect the transmission operator will curtail load based on the type of transactions flowing across the line. Transmission transactions are categorized into one of seven (7) priorities. The TLR priority levels are:

<u>Priority</u>	<u>Definition</u>
1	Service over secondary receipt and delivery points.
2	Non-Firm Point-to-Point. Hourly Service.
3	Non-Firm Point-to-Point. Daily Service.
4	Non-Firm Point-to-Point. Weekly Service.
5	Non-Firm Point-to-Point. Monthly Service.
6	Network Integration Transmission Service from sources not designated as network resources.
7	Firm Point-to-Point Transmission Service and Network Integration Transmission Service from Designated Resources.

Priority one is the least firm transaction and is first subject to curtailment when a TLR is in effect. Priority levels six and seven are the most firm and are only curtailed under the direst circumstances. In recent years the number of TLR's has grown dramatically in some of the operating regions.

### **Ancillary Services**

Utilities must do more than just supply energy to a load. There are ancillary services that are required to ensure adequate reliability and quality of the power delivered. Ancillary services that utilities must provide include scheduling, reactive supply, frequency response, energy imbalance, spinning reserves, and supplemental reserves.

NERC requires utilities to have *reserves* of generating capacity above the load requirement to meet unexpected contingencies. The amount of reserves is dictated by the largest contingency that could affect the utility, such as the largest power plant on the system or the most critical transmission line. *Spinning reserves* are reserves that are on-line and available immediately such as excess capacity in a running generator. *Supplemental reserves* are resources that can be started up in a short time period such as a combustion turbine unit, which might be able to start within 15 minutes.

*Reactive power* is another ancillary service. Electrical power is made up of two components "active" power and "reactive" power. Active power is measured in watts and is considered the component of power that does useful work. Reactive power is used to create electric and magnetic fields in equipment such as motors. Reactive power is essential for maintaining adequate voltages on the power grid. It cannot be transmitted over load distances and therefore must be supplied from a generator near the load, regardless of where the power was generated.

*Scheduling* is an ancillary service for approving and implementing interchange schedules. The scheduling entity arranges transmission paths and calls on the generation as needed to meet the planned load requirement. A process known as *tagging* is used to identify the generation source, transmission path, and intended load for a given interchange. Everyone involved in the

transaction from the energy provider, transmission provider, control areas through which the power will flow, and the energy user must all approve the tag.

Regulation, or *Frequency response*, is another ancillary service. Frequency response is the moment-to-moment load following of the on-line generation to continuously balance the generation to the load.

*Energy imbalance* occurs when there is a difference in the scheduled and actual delivery of energy to a load during a single hour. Whoever makes up for the energy imbalance must be compensated.

## **IV. Landmark Legislation**

As you would expect, in the last one hundred years there has been a large amount of Federal legislation concerning electric utilities. Some of the most significant legislation includes the Public Utility Holding Company Act (PUHCA), Public Utility Regulatory Policies Act (PURPA), Energy Policies Act of 1992 (EPAct '92), Energy Policies Act 2005 (EPAct '05), FERC rule 888 and 889, and FERC rule 2000. The following is a brief review of each of these pieces of legislation and rules.

### **Public Utilities Holding Company Act of 1935 (PUHCA)**

By the 1930's almost half of the electric utility generation in the U.S. was controlled by only three giant holding companies. Many holding companies were accused of using various schemes to inflate the cost of operations for their subsidiaries, which were regulated by the states. These schemes made state regulation largely ineffective. To help rein in the excessive conglomeration and abuses by the utility industry, Congress passed the Public Utilities Holding Company Act (PUHCA) in 1935. This legislation did not prevent the operation of holding companies, but it did limit the structure. The Securities and Exchange Commission (SEC) was charged with administration of PUHCA.

The PUHCA Act says there can only be two levels in the holding company, a parent company and one level of subsidiaries below the parent. Furthermore, the operating companies must have contiguous territories (i.e. a holding company could not own a utility in Illinois and California.) By allowing a basic holding company structure to continue to exist, the utilities could take advantage of the economies of scale of a large organization. The Act also limited the power of holding companies to engage in businesses that were not essential to the operation of a utility. This requirement essentially eliminated the ability of non-utilities from engaging in wholesale electric power sales.

After PUHCA the number of holding companies dropped dramatically from over 200 holding companies in 1935 to less than 20 by the 1950's.

### **Public Utility Regulatory Policies Act of 1978 (PURPA)**

The National Energy Act was passed in 1978 as a result of the energy crisis in the mid-1970's. The purpose of the National Energy Act was to help the Nation transition from the previous low-cost energy era to a period where rising energy costs were likely to be experienced. One section of the National Energy Act dealt with the electric power industry. This section, the Public Utility Regulatory Policies Act (PURPA) was included to help develop renewable energy, alternative energy sources, increase conservation, and help provide equitable rates for all electric customers.

Section 210 of PURPA requires electric utilities to buy power from facilities that met certain criteria. These Qualifying Facilities (QF's) were supposedly facilities that either generated power from a renewable resource, such as wind, or where the power was co-generated as by-product of a manufacturing process. The Act requires utilities to buy all the power the QF's want to sell and the utility must pay its "avoided cost" for the power. Avoided cost is the

incremental cost of generating the next unit of electrical energy. This feature of PURPA created a unilateral market for power that required the utilities to buy any power the QF's wanted to sell, even if the utility already had sufficient capacity to meet its own needs.

PURPA did provide restrictions on the allowable size and operating efficiency of co-generators, but the generator size for renewables was not limited. To be considered a renewable resource under PURPA the energy source must be from solar, wind, biomass, waste, geothermal, or hydroelectric. The Act also limits utility equity ownership in QF's to less than 50%.

### **Energy Policy Act of 1992 (EPAct '92)**

The Energy Policy Act of 1992 (EPAct '92) created a new category of power producers known as exempt wholesale generators (EWG's). The Act reformed some of the PUHCA requirements, which allowed companies to build generating plants that could sell power in an open market environment. Both utility-affiliated and non-utility affiliated entities could build and operate power plants. Unlike PURPA, utilities are not required to purchase the output from EWG's and the EWG's do not have to generate from co-generation or renewable sources.

EPAct '92 broadened the authority of FERC to require that utilities provide transmission service to the EWG's to ensure that their power can reach a market by requiring the host utility to "wheel" the power. *Wheeling* is a term used to describe the transmission of power across one utility system to another system for a third party.

### **FERC Rule 888 and 889**

Even with the advent of EPAct '92 and FERC's expanded role in ordering transmission access, some felt that existing electric utilities were not treating independent power producers fairly. To remedy this concern, FERC issued orders 888 and 889 in 1996. The purpose of Rule 888 was to eliminate anti-competitive practices of utilities concerning transmission, require a universally applied Open Access Transmission Tariff (OATT), and to allow the utility to recover any "stranded costs" that result in a competitive market.

This rule required virtually all transmission utilities to develop an OATT that specifies the terms and conditions of the use of its transmission lines. The rule also requires the utility to unbundle their transmission service such that wholesale generation, transmission, and ancillary services are priced separately. Ancillary services that utilities must provide include scheduling, reactive supply, frequency response, energy imbalance, spinning reserves, and supplemental reserves.

A companion to Order 888 is Order 889, which requires transmission owners to provide non-discriminatory, timely, accurate, and daily information to all transmission users. The mechanism for delivering this information is the Open Access Same-Time Information System (OASIS). OASIS is an interactive, Internet-based system that has information on transmission capacity, transmission reservations, ancillary services, and prices. In essence, OASIS makes a competitive transmission market practical.

### **FERC Rule 2000**

In 1999, FERC issued Order 2000, which encourages the creation of Regional Transmission Organizations (RTOs). Apparently FERC's rationale for encouraging the formation of RTO's is that bringing transmission systems under the control of a regional operator will eliminate discriminatory practices of transmission owners and help the industry achieve a fully competitive market. As a result of Order 2000 a few RTO's have been formed, but most of the Nations transmission system continues to operate outside of an RTO.

### **Energy Policy Act of 2005 (EPAct '05)**

The most comprehensive piece of legislation concerning the electric utility industry was passed in 2005. The Energy Policy Act of 2005 (EPAct '05) was meant to stimulate the energy markets by providing tax incentives and to strengthen the Nation's energy infrastructure through expansion and oversight. The Act broadly covers all forms of energy, and the portion that deals with the electric utility industry is known as the Electricity Modernization Act of 2005 (EMAct '05). EMAct '05 covers (among other things) reliability standards, transmission infrastructure modernization, transmission rate reform, amendments to PURPA, and the repeal of PUHCA.

One item that the IOU's heavily lobbied for – and got – was the repeal of PUHCA. Congress reasoned that there are now sufficient rules and procedures in place to render PUHCA obsolete. The belief is that the repeal of PUHCA will lead to new investment in the electric system infrastructure.

The Act has tax incentives for developing new generation sources including significant credits for the first six new nuclear plants developed in the U.S. There are incentives for clean coal, renewables, and hydrogen fuel plants.

PURPA was not repealed, but the Act results in major modifications to PURPA. With EPAct '05 there are no longer limitations on utility ownership of qualifying facilities, and utilities are no longer required to purchase QF generation at avoided cost, except for existing contracts and certain super-cogen-QF's. The Act requires that new QF's have a real cogeneration purpose and that it is not intended solely for electricity generation. Utilities only have to purchase power at avoided costs from the new super-cogen-QF's if the QF does not have access to a competitive market. Broadly, a competitive market is any area where an RTO exists. Another amendment to PURPA requires utilities to consider certain technological and conservation activities. Specifically, utilities must consider, "smart" metering, net metering, distribution generation interconnection, fuel migration, and generation efficiency. Smart metering is advanced metering that allows time of use rates and load signals for peak energy cost periods. Net metering allows a generation source, such as a small photovoltaic system to run the meter backwards when it has excess capacity essentially "banking" the extra power for future use. Fuel migration means the utility must develop a plan to minimize its dependence on one fuel source and a plan to use more renewables.

Since some utilities, such as cooperatives and municipals, cannot take advantage of energy tax credits, Congress added a Clean Renewable Energy Bond (CREBs) that can be used to finance certain generation projects such as renewable sources.

EPAct '05 amends the Federal Power Act to impose mandatory reliability standards on the owners of the bulk transmission system. The Act empowers the FERC to develop an Electric Reliability Organization (ERO) to provide oversight of the transmission system. NERC will assume the role of the ERO. The ERO will have the power to impose penalties on transmission system operators who violate reliability standards.

Another amendment to the Federal Power Act by EPAct '05 is the authority for FERC to correct a system deficiency by mandating the construction of transmission infrastructure if the deficiency has the potential to impact national energy policy, national defense, or homeland security. The deficiency area is known as a National Interest Electric Transmission Corridor (NIETC) and is any area that is experiencing capacity constraints or congestion that has an impact on National policy.

Other provisions in the Act require FERC to establish incentives for utilities to join an RTO and to establish incentives for utilities to invest in new transmission capacity.

EPAct '05 is an extremely broad piece of legislation and is still relatively new. There are opponents and proponents of the Act, and it will take years to see the impact of the Act on the electric utility industry.



## V. Future Considerations

With market participants and regulators pushing for more open access to the transmission system, the industry is struggling to find ways to allow access and maintain reliability. This is occurring at a time when electricity demand is growing, and utilities are not investing in new transmission facilities. The result is transmission bottlenecks and an increase in the number of TLR's. As mentioned in the previous section, recent legislation is aimed at opening access to the transmission system and encouraging new investment in utility infrastructure. One of the ways to do this is with an RTO.

### Regional Transmission Organizations

One solution that the industry is considering is the formation of Regional Transmission Organizations (RTO's) and Independent System Operators (ISO's). An ISO is a neutral operator responsible for maintaining the generation-load balance of the system in real time. FERC believes that a well designed RTO is an effective method to address the market and reliability coordination problems that exist today. Since 2000, FERC has been encouraging the voluntary formation of large RTO's. The new EAct '05 gives utilities more incentives to join an RTO.

The basic purpose of an RTO is to set rates for transmission service that eliminate rate "pancaking", ensure all parties have fair access to the transmission system, be responsible for planning future transmission additions, facilitate real-time and day-ahead markets, and provide demand response programs. FERC says that there are eight functions that an RTO must perform. They are:

1. **Tariff Administration and Design.** The RTO will be the sole administrator of its own tariff and, therefore, it will be the sole decision-making authority on provision of transmission service including the decision to establish new interconnections.
2. **Congestion Management.** The RTO will ensure the development of market mechanisms to manage transmission congestion. These mechanisms should provide price signals to transmission customers regarding the consequences of their transmission usage decisions. Locational marginal pricing is a method to accomplish this goal.
3. **Parallel Path Flow.** The RTO must implement procedures within 3 years of start-up to address the problems associated with interregional parallel path flow and implement procedures immediately for regional parallel path flow. Parallel path flow refers to the fact that electricity flows over transmission lines according to the laws of physics. Because of these laws, the power generated in one region may flow over the transmission lines of another region inadvertently affecting the ability of the other region to move power.
4. **Ancillary Services.** The RTO must serve as the provider of last resort for all ancillary services as required in Order 888. The RTO should promote creation of competitive markets for procurement of these services.

5. Open Access Same-Time Information System (OASIS) and Capability Calculations. The RTO should act as a single OASIS node. The data elements of total transmission capability and available transmission capability, which are stored on the OASIS and used by potential transmission customers, will be calculated by the RTO, or if provided by the transmission owner, verified by the RTO.
6. Market Monitoring. The RTO will submit to FERC a market monitoring plan that (1) ensures that there is objective information about the markets, (2) contains procedures for proposing efficiency improvements, market flaws, and market power, and (3) contains procedures to evaluate the behavior of market participants.
7. Planning and Expansion. The RTO must develop a planning and expansion proposal that (1) encourages market-motivated operating and investment actions for preventing and relieving congestion, (2) accommodates efforts by state regulatory commissions to create multi-state agreements to review and approve new transmission facilities and coordinates with existing regional transmission groups, and (3) files a plan with milestones showing that the RTO will meet its planning and expansion requirements no later than 3 years after start-up.
8. Interregional Coordination. The RTO will develop mechanisms to ensure the integration of reliability practices within an interconnection and market interface practices among regions.

The formation of RTO's has been slow because today's transmission system is owned by many different companies and finding ways to sufficiently incentivize them has been difficult. Also, effective operation of an RTO is technically challenging because the traditional utility model was never intended to operate as an open access market.

To be considered a functioning RTO, FERC requires the RTO to meet the following requirements,

1. The RTO must be independent of the market participants.
2. The RTO must serve a sufficiently large region and be configured such that it can be effective.
3. The RTO must coordinate security (reliability) for its region.
4. The RTO must have exclusive authority for maintaining short-term reliability in its region.

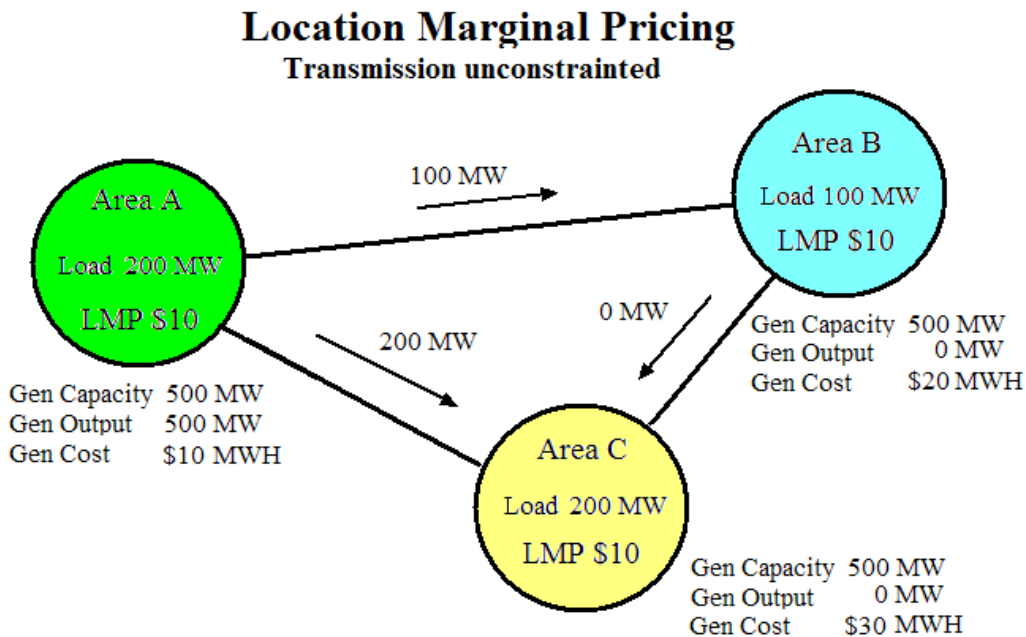
The major issues related to an RTO are transmission access, pricing and how to give transmission owners proper signals to upgrade and build new transmission lines. The industry is working on how to price future transmission access. Traditional transmission rates are set by each transmission owner in a load flow path, which may result in pancaking of rates. Some say that pancaking distorts the market. One solution to pancaking is the use of a "license plate" rate. License plate rates are based on paying a rate that is derived from the costs of the transmission system where the ultimate load is connected. Many participants are pushing for a "postage stamp" rate for the higher voltage bulk transmission systems. With postage stamp rates, all

customers pay the same rate for transmission access regardless of the length of the transmission path.

### Locational Marginal Pricing

Locational Marginal Pricing, or LMP, is a procedure that is being used in some RTO's to ensure reliable operation of the transmission system while allowing a least-cost approach to dispatching generation. The intent of LMP is to offer clear market signals for energy costs and to encourage the development of new transmission to relieve congestion. The basic premise of LMP is that there is a cost of having generation remote from the load center, and LMP attempts to quantify the cost.

To help us understand LMP, consider the following simple example. In Figure 10 we have a three-node electric system with generation in each of the three areas: "A", "B", and "C". In addition there are electrical loads in each of the three areas. In area "A" there is 500 MW of generation capacity, which can be economically dispatched at \$10 per megawatt-hour (MWH). There is also 200 MW of load in area "A". Area "B" also has 500 MW of generation capacity, but the cost of operation for the generator is \$20 MWH. There is 100 MW of load in Area "B". Area "C" has a 500 MW generator, but its cost of operation is \$30 MWH. Area "C" has 200 MW of load.

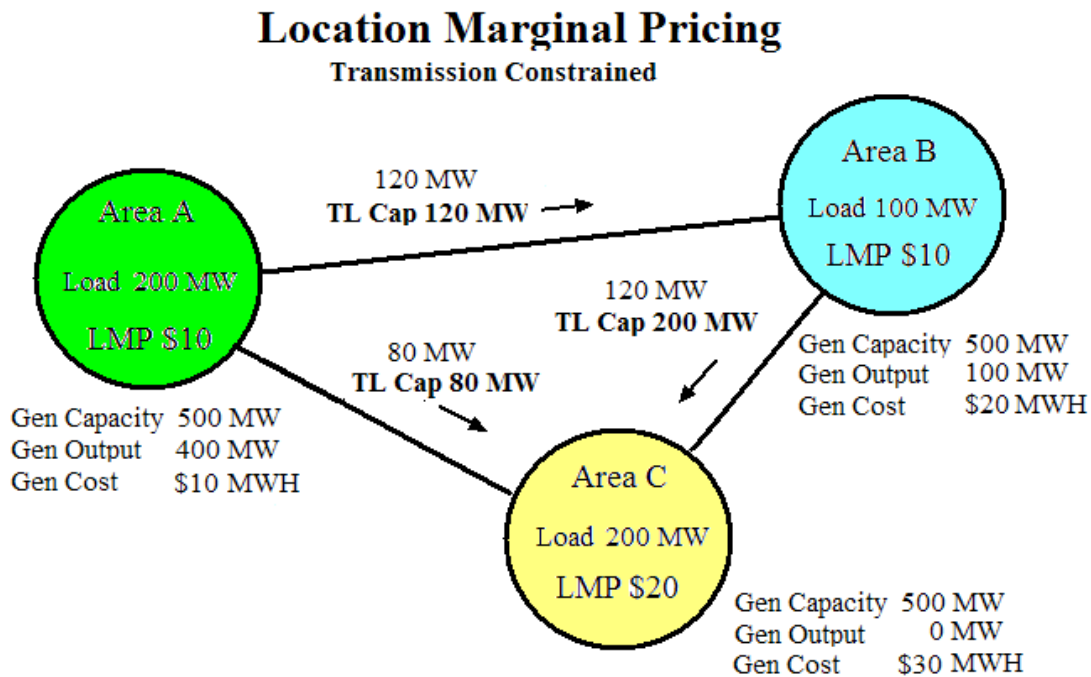


**Figure 10**

Absence the transmission interconnects, each area would service its own load and the marginal cost of electricity for areas "A", "B", and "C" would be \$10, \$20, and \$30 MWH respectively. But, because of the transmission system, the lower cost generation in area "A" can be shared with the other, higher cost areas. Figure 10 assumes that the transmission system is not constrained and can deliver the full requirements of the other areas. In this scenario, the

generator in area “A” will supply the 200 MW of local, or native load, and will ship 100 MW of generation to area “B” across transmission line A-B and 200 MW of generation to area “C” across transmission line A-C. The generators in areas “B” and “C” will not run. Theoretically, transmission line B-C will not have any load flowing through it.

The situation will change if the transmission line is constrained. Consider the scenario shown in Figure 11. This scenario is the same as the previous one, except that transmission line A-B is limited to transmitting only 120 MW of capacity, A-C has a limit of 80 MW, and transmission line B-C is limited to 200 MW.



**Figure 11**

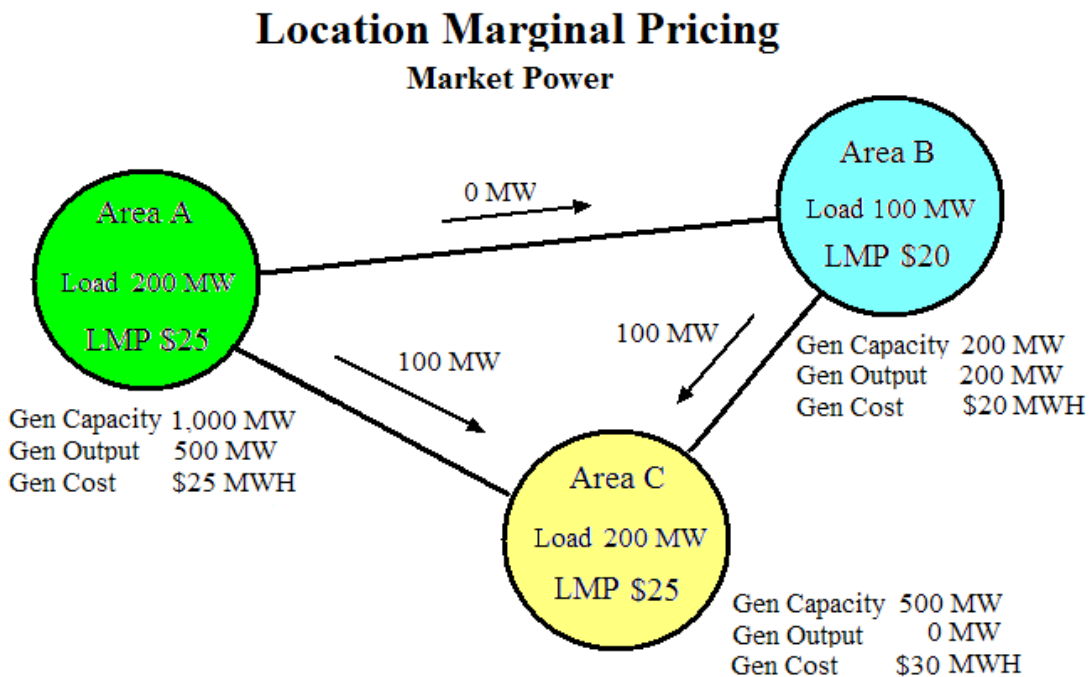
In this example, the generator in area “A” will still supply its native load of 200 MW, but can only ship 80 MW to area “C” across the transmission line A-C. The generator can still supply the full 100 MW of load in area “B” and, furthermore, can supply an additional 20 MW (up to the full transmission capacity of line A-B) to area “C” through A-B and B-C. This satisfies the load in both areas “A” and “B”, but leaves area “C” 100 MW short. Since the generator in area “B” is the next least-cost generator it is dispatched to supply the 100 MW of generation shortfall into area “C”. Therefore, the LMP for area “A” and “B” is \$10 MWh since they are served by the generator in area “A”, and the LMP for area “C” is \$20 MWh since the last unit dispatched into area “C” has a dispatch cost of \$20 MWh. Since LMP is based on *marginal costs*, the LMP for area “C” is not a weighted average of the generation at “A” and “B”, but is based on the last unit dispatched.

As you can see from these two examples, the LMP is based on both the least-cost generation (based on the bids submitted by the generators) and the transmission congestion. These

examples are extremely simplified. In reality, the electric grid has hundreds of interconnections, many generators bidding into the market, and time-varying transmission constraints.

With LMP, transmission owners have Financial Transmission Rights (FTR's) for their transmission lines. An FTR is a financial right, or contract, which entitles the holder to a stream of revenues, based on the hourly energy price differences across the transmission line. This gives the transmission owner a certain right to the use of their own transmission line and protects the owner from the impacts of transmission congestion for their native load use of the line. There can be a secondary market for FTR's where they are bought and sold based on market conditions.

One final note issue about LMP is the possibility of a generator manipulating the market. Consider the example in Figure 12. This is the same as the first example, with an unconstrained transmission system except generator "A" has a capacity of 1,000 MW and generator "B" only has 200 MW of capacity.



**Figure 12**

In this scenario the generator in area "A" bids his price at \$25 MWH instead of his marginal costs of \$10 MWH. At \$25 MWH, generator "A" will not get all of the business since generator "B" will run first at \$20 MWH up to its capacity of 200 MW. However, when the capacity of generator "B" is exceeded, generator "A" then runs and the LMP is set at his bid price of \$25 MWH.

Under the first scenario generator "A" would have an hourly revenue of 500 MW \* \$10 MWH or \$5,000 per hour. However, under this scenario, generator "A" would receive revenue of 300 MW \* \$25 MWH, or \$7,500 per hour. By artificially setting his bid price high, generator "A"

has manipulated the market resulting in an artificially high LMP. Since generator “A” has extra capacity he can sell this remaining capacity at the higher LMP. This is known as *market power*, the ability for one entity to affect the price of the market by their actions. Market power is an issue the FERC must address for LMP to work effectively.

## Summary

The electric transmission grid is one of the most significant engineering accomplishments of the past 100 years. Reliable electric energy is vital to a modern society and has become a key component of our national security. Just about everything we do requires access to a reliable and economical supply of electricity.

The electric utility industry is an enormously complex machine that requires significant real-time production and monitoring as well as delivery over a transmission grid that is a complex network of interconnected systems.

Today we are pushing the grid to use it in ways it was never intended to be used. If we are to continue to develop an open market for electrical generation and transmission, we must find new ways to operate the grid to maintain the level of reliability that we have come to expect.

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