Electricity Regulation in the United States

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I. The Electricity Market in the United States[1][2]

A. 3,269 electricity providers in total[3]

- 2008 publicly owned utilities (9.9%)
- 877 co-operatives (4.7%)
- 202 investor-owned utilities (39.9%)
- 9 federal utilities (6.7%)

B. Generation

- Coal, Natural Gas and Nuclear Energy are the primary sources of electricity generation. Together, they account for 85 – 90% of total net generation from 1997 – 2008.
- Renewable energy (excluding conventional HEP) accounts for the remaining 10 %[4]
- Non-utility generators or independent power producers are generators which own one or more power plants but do not provide retail service. They sell power to utilities, marketers or to direct access customers (often industrial) through brokers.

C. Power sales

- Marketers sell electricity at wholesale, but do not generate, transmit or distribute electricity. Instead they buy power from multiple suppliers on long term or spot market bases for resale.
- Other wholesale power suppliers own their own power plants.
- As of June 2007, there were 438 independent power marketers, 123 power marketers affiliated with public utilities, and 46 power markers affiliated with financial institutions, each with authorization to sell power at wholesale.

D. Transmission

- Under the regulation of the FERC, transmission providers are required to unbundle its services and declare terms and conditions for the use of their transmission system.
- Transmission providers mainly transfer operational control of transmission assets to ISO or RTOs for operating the regional transmission grid and administering wholesale markets.

[1] This research is generously funded by the Research Grants Council of Hong Kong under a Public Policy Research Grant numbered 7001-PPR-09.

[2] Pillsbury Getting the Deal Through 2011
[3] Figures according to the American Public Power Association (APPA) 2010 – 11 Annual Directory and Statistical Report.
[4] Figures according to the Energy Information Administration (EIA), at www.eia.gov/renewable/annual/preliminary/index.cfm

II. Regulatory Developments

In the 1980s, with the enactment of the Public Utility Regulatory Policy Act (PURPA) in 1978, independent entrepreneurs were encouraged to compete to supply power and to increase the efficiency of the generation sector. Retail suppliers were required to buy power from qualifying independent power producers (small generators or renewable generators, collectively "QF") at a price equal to the "avoided cost" of not having to invest in generation facilities and produce the power. The "avoided cost" was often set at a very high level.

This model turned out to be unviable at first. Retail suppliers were tied in to long term contracts and were unable to react to changes in the cost of different generation sources. As nuclear energy became more expensive and the price of natural gas dropped in the 1990s, consumers were paying high prices for uneconomic choices, well above the actual cost of building gas- or coal-fired plants.

In the 1990s, a number of states undertook measures to require or encourage vertically integrated utilities to disaggregate into separate generation, transmission or distribution entities.

In 1996, the FERC issued a series of orders designed to foster competition through better access to transmission services[5]. Pursuant to these orders, Independent System Operators (ISOs) and regional transmission organizations (RTOs) were formed as independent operators of transmission networks. RTOs and ISOs are responsible for granting access to transmission over large interstate areas by coordinating, controlling and monitoring power generation with large transmission grid across state borders. Transmission service providers were strongly encouraged to join an RTO or ISO[6]. In 2007, the FERC mandated the provision of transmission services on a nondiscriminatory, just and reasonable basis[7].

In August 2005 the Energy Policy Act 2005 was enacted, which reaffirmed the government's commitment to competition in wholesale power markets. In 2008, the FERC finalized regulations aimed at improving the overall competitiveness of organized wholesale electric markets through the use of demand response and by encouraging long-term power contracts, strengthening the role of market monitors and enhancing RTO and ISO responsiveness[8]. These measures will be discussed in greater detail below.

In 2003, the US Energy Information Administration reported that 23 states had taken action to implement **retail choice** in the electric sector. **Retail choice programs let customers choose among competitive suppliers, in default of which a retailer will be assigned to the customer**. However some states have since slowed their efforts to promote retail choice. In 2007 Virginia ended a 10 year experiment with deregulation and restored full-cost of service regulation of retail sales. In 2001, California suspended its retail access programme, but reinstated partial direct access in 2010, to be

[5] FERC Order No. 888
[6] FERC Order No. 2000
[7] FERC Order No. 890
[8] FERC Order No. 719, 719A and 719B

phased in over a period of 4 years. **Today 15 states and the District of Columbia have active retail choice programs for residential electricity customers**[9].

III. The Regulatory Authorities

A. Federal Energy Regulatory Commission

The FERC is an independent agency that regulates the interstate transmission of electricity, natural gas and oil. The FERC derives jurisdiction mainly from the Federal Power Act (FPA) and the Energy Policy Act 2005 (EPA 2005). It is authorized to have 5 commissioners, each serving a 5 year term[10]. Its responsibilities include:

- Regulates transmission and wholesale sales of electricity in interstate commerce
- Reviews certain mergers and acquisitions and corporate transactions by electricity companies
- Protects the reliability of high voltage interstate transmission system through mandatory reliability standards
- Review siting applications for electric transmission projects under limited circumstances
- Administers accounting and financial reporting regulations and conduct of regulated companies
- Promotes strong national energy infrastructure, including adequate transmission facilities
- Enforces FERC regulatory requirements through imposition of civil penalties and other means

The FERC has authority to impose civil penalties in the amount of US $ 1 million per day per violation[11] for regulated activities within its jurisdiction, as well as make cease and desist orders to enjoin offending activity.

B. State Public Utility Commissions (PUCs)[12]

State PUCs perform intra-state utilities regulation. State PUCs are collectively represented by the National Association of Regulatory Utility Commissioners (NARUC), which bridges individual state PUCs and FERC, Congress and the Courts. Its responsibilities include:

- Regulation of retail sales of electricity
- Approval for the physical construction of generation facilities within states

C. North American Energy Reliability Corporation (NERC)

Develops and enforces mandatory reliability requirements in the North American bulk power system. The NERC is subject to FERC oversight and enforcement.

The NERC assesses adequacy annually via a 10-year forecast, and summer and winter forecasts; monitors the bulk power system; and educates, trains and certifies industry personnel.

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[9] US Energy Information Administration, "Electricity retail choice is mandated in Texas ad growing in three States", 18 May 2011, http://www.eia.gov/todayinenergy/detail.cfm?id=1430
[10] An Overview of the FERC: http://www.ferc.gov/about/ferc-does/ferc101.pdf
[11] FPA Sections 316 and 316A
[12] NARUC links to state PUCs: http://www.naruc.org/commissions.cfm

IV. Federal Regulation

A. Promoting Alternative Energy Sources

Mandatory Purchase and Sale Requirements on Electric Utilities

Mandatory purchase and sale requirements aim to promote alternative energy resources. It creates demand for renewable generation sources by requiring suppliers to buy electricity from clean generation facilities.

Under the Public Utility Regulatory Policies Act of 1978 (PURPA), electric utilities were obligated to purchase or sell electric energy from or to a facility that is a "qualifying cogeneration or small power production facility" (Qualifying Facility), at special rates.

A **small power production facility** is a generating facility of 80 MW or less whose primary energy source is renewable, biomass, waste or geothermal resources. A **cogeneration facility** is a generating facility that sequentially produces electricity and another form of useful thermal energy in a way that is more efficient than the separate production of both forms of energy.

However in 2006 FERC issued an order which permits the termination of the requirement for utilities to enter into new contracts to sell energy to or purchase energy from a Qualifying Facility after the electric utility files for relief from FERC.

Qualifying Facilities (QFs)[13]

Qualifying small power production or cogeneration facilities (see above) enjoy benefits under Federal, State and local laws:

1. **Right to sell energy or capacity to a utility**
   Provided that the purchasing utility has not been relieved from QF purchase obligation by the FERC, QFs may sell to a utility at the utility's avoided cost or at a negotiated rate.

   Avoided cost is the incremental cost to an electric utility of electric energy or capacity which such utility would generate itself or purchase from another source.

   QFs may also sell energy either "as available" or as part of a contract for a fixed term.

2. **Right to purchase certain services from utilities and interconnection**
   Provided that the selling utility has not been relieved from QF sales obligations, QFs have the right to purchase supplementary power, back-up power, maintenance power and interruptible power at rates which are just and reasonable, based on accurate data and consistent system-wide costing principles that apply to the utility's other comparable customers.

[13] http://www.ferc.gov/industries/electric/gen-info/qual-fac/benefits.asp

QFs also have the right to interconnect with a utility by paying a nondiscriminatory interconnection fee approved by the state regulatory authority or a non-regulated electric utility.

3. **Relief from certain regulatory burdens**
   Cogeneration facilities of any size; small power production facilities 30 MW or smaller, and geothermal and biomass small power production facilities of any size, are exempt from most FPA provisions, apart from rate regulation provisions.

Renewable Portfolio Standards (RPS)
[*state implemented*]

An RPS requires utilities and other retail electric providers to supply a specified minimum amount of customer load with electricity generated from renewable energy resources by a certain date[14]. RPS aim to increase renewable energy generation using a cost-effective, market-based approach, so that ultimately renewable energy will be technologically advanced and economically competitive with conventional forms of electric power.

Regulated utilities are required to progressively increase renewable electricity generation. In some states, percentages are set at certain milestone years (i.e. 11% by 2015, 20% by 2020), while in others, only the final percentage is prescribed. Specific RPS for each type of renewable energy resource may also be specified (i.e. 5% solar, 5% wind etc.)

Tremendous diversity exists among the 33 states which have adopted an RPS, with respect to the minimum requirements of renewable energy, implementation timing, eligible technologies and resources.

Energy Efficiency Resource Standards[15] (EERS)
[*state implemented***]**

EERS aims to promote energy efficiency. It is similar in concept to an RPS, in that EERS requires utilities to reduce energy use by a specified and increasing percentage or amount each year. EERS can be implemented in addition to RPS, or in combination with the RPS, allowing suppliers to substitute EERS with RPS, and vice versa.

Energy efficiency uses less fuel to produce the same or greater amount of usable energy from a given energy source. Alternatively, conservations may take the form of temporary reductions in energy use.

Status of adoption:

- 18 states with standards (EERS)
- 10 states with non-binding efficiency goals
- 15 states with peak reduction targets
- 34 states with an EERS, pending regulations or an EE goal

Incentives or rewards for electric utility efficiency reductions

[14] http://www.dsireusa.org/
[15] http://www.ferc.gov/market-oversight/othr-mkts/renew/othr-rnw-eers.pdf

- 13 states approved decoupling mechanisms
- 9 states approved lost-revenue recovery mechanisms
- 11 states have pending cost-recovery mechanisms
- 21 states use incentives or reward utilities that meet savings targets

Production Incentives

- **Production tax credits** for renewable energy sources[16].
- US $800 million **clean renewable energy bonds** have been authorized to finance qualifying renewable energy facilities for governmental, public power and electric cooperative entities.
- **Incentive-based rate structure** for interstate transmission of electric energy. The incentive rate structures must provide a return on equity (ROE) that attracts investment and allows recovery of all costs prudently incurred in complying with new reliability standards.
- 8-year extension of 30% **investment tax credit** for solar energy and fuel cells
- Investment tax credits for qualifying cogeneration systems, small wind and geothermal heat pump systems, and qualifying coal and gasification projects
- Increased tax credits for projects that achieve the greatest percentage of carbon dioxide separation and sequestration
- Loan guarantee programme for renewable energy projects that began construction by 30 September 2011. Programmes include biomass programme, geothermal technologies, solar energies, hydrogen, fuel cells and infrastructure technologies, wind and hydropower technologies.

Integration of Small Renewable Projects

In order to promote competition and encourage alternative energy, new and independent generators must be able to **access and connect** to the electricity grid at **reasonable rates**.

Due to the geographical constraints inherent to certain types of renewable energy generation (i.e. wind, solar and biomass resources), existing interconnection points in the transmission network may not be accessible to independent generators. Hence in order to enable new generators to connect to the transmission grid, the FERC has specific interconnection policies for locationally constrained electric power generation to enable their integration into the transmission grid.

B. Interconnection Policies

Open Access

FERC jurisdictional transmission providers are required to provide interconnection service under the terms of an **Open Access Transmission Tariff** (OATT). FERC implemented rules to **standardize agreements and procedures**, and requires transmission providers to interconnect generators to the grid in a non-discriminatory manner.

[16] www.uscusa.org/clean_energy/solutions/big_picture_solutions/production-tax-credit-for.html

Under the OATT, the **FERC has authority to regulate the rates, terms and conditions** of any wholesale sales transaction using such facilities.

Access to interconnection points is essential for generation plants in inconvenient or remote locations to connect to the transmission grid and ultimately to sell the power generated.

Under the standard interconnection procedures, generators pay the full cost of interconnection facilities up front. The generator is then reimbursed for the cost of such facilities through credits for future transmission service.

Independent System Operators and Regional Transmission Organizations may propose changes to the standard agreement and procedures, subject to FERC authorization.

Environmental Supervision

Transmission providers must perform impact studies for approval by the FERC (inter-state) or the relevant local planning authority.

Where necessary, it must consider alternatives for the siting and construction of interconnection points.

C. Transmission Networks

Organization

The FERC has encouraged the formation of Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs), which are formed by utilities that transfer operational control of their transmission assets to the ISO/ RTO. The ISO/ RTO then operates the transmission grid and administer the wholesale markets.

ISOs/ RTOs are important for the development of systems of joint pricing for interstate transmission services. This prevents the layering of transmission rates across multiple transmission lines from one owner to another.

Construction

EPA 2005 directed the DOE to conduct a **nationwide study of electric transmission congestion** and **identify areas in which transmission capacity constraints or congestion will adversely affect consumers**. These corridors were designated as National Interest Electric Transmission Corridors.

The DOE is currently collaborating with the FERC to prepare drafts of transmission congestion studies and environmental analyses for proposed Transmission Corridors.

In July 2011 FERC issued Order No. 1000, which lays out certain efficient and cost effective ways to meet regional transmission needs. However the impact of the order is unknown as implementation is left to public utility transmission planners.

Demand Response Programs[17]

Demand response programs employ smart/ advanced meters to allow electricity consumers to respond to price fluctuations in electricity. By reducing electricity consumption at peak hours, DSR helps reduce congestion and increase the reliability of transmission services. With suitable demand response, the need for construction and replacement of costly infrastructure is reduced.

The FERC facilitates the development and use of demand response programmes. All ISOs and RTOs have been directed to develop measures to compensate consumers who provide demand response[18].

Access

Fair and non-discriminatory access to transmission services is crucial to promoting the use of alternative and third party power supplies, as part of the OATT. Access allows new generation facilities to connect to the transmission grid and sell electricity in the wholesale market.

1. **Promoting transparency and access to information through the Open Access, Same-time Information System (OASIS):**

Transmission providers are required to maintain an OASIS to public information regarding its services, rates, available transmission capacity (ATC), business rules, practices and standards that related to the transmission services.

The method of calculation of ATC is regulated by the FERC, and must be transparent and consistent in order to provide best information to customers.

2. **Promoting third party access by requiring electric utilities to coordinate open transmission planning between regions:**

Transmission services are subject to the ATC of providers. Apart from regulating the method of calculation of ATC and mandating the publication of ATC information, the FERC also requires transmission providers to implement new service options for long term firm point-to-point customers.

Where the calculation of ATC is opaque and service options are limited, providers may discriminate among customers based on an insignificant insufficiency in ATC during the service period requested by customers.

Providers are now required to consider their ability to offer modified forms of planning redispatch or conditional firm options to accommodate customer

[17] NARUC-FERC Demand Response Collaborative: http://www.naruc.org/Ferc/default.cfm?c=2
[18] FERC Order No. 745 on 17 March 2011

requests.

Rates and Terms

1. Just and reasonable standard for rates and terms of service

Electric utilities are required to publish rates for transmission and ancillary services under the OASIS.

The FERC determines whether a particular rate is just and reasonable via a traditional **cost-of-service ratemaking inquiry** that **balances ratepayers' and the utilities' financial interests** to realize a rate within the zone of reasonableness.

As regards transmission providers outside of the FERC's jurisdiction, the FERC is empowered by the EPA 2005 to require such providers to open access to their transmission system at terms and conditions comparable to those which the unregulated providers provides to itself. Small providers selling less than 4 million MWh of electricity annually or which does not own or operate the transmission facilities are exempted.

At the state level, tariffs for distribution services are similarly approved and reviewed by State Public Utility Commissions, based on the just and reasonable standard via the cost-of-service ratemaking inquiry.

2. Approval before commencement of service

Rates and terms of service must be approved by FERC prior to the commencement of service to allow for review, public notice and comment.

3. Review and Challenge[19]

Under the Federal Power Act, the FERC may on its own initiative conduct investigations to review rates and terms of transmission services to ensure that they are just and reasonable and not unduly discriminatory or preferential.

Rates may also be challenged by third parties for being unjust, unreasonable, unlawful or discriminatory.

4. Remedy

If a tariff or contract is found by the FERC to be unjust and unreasonable, it will order mitigating revisions.

FERC may require the sellers to refund the difference between the rates collected and the rates determined by the FERC to be just and reasonable,

[19] FPA Section 206

from the date of commencement of the investigation.

D. Wholesale Sales of Electric Energy

Tariff Regulation

FERC regulates non-price terms and conditions in the market-based rate tariff, but it does not dictate specific non-price terms and conditions in wholesale power sales contracts.

Pursuant to FPA Section 201, the FERC has authority over all wholesale sales of electricity to ensure that the wholesale rates are just, reasonable, and not unduly discriminatory or preferential. In making its determination, the FERC employs a cost-of-service ratemaking inquiry.

Market Based Rates[20]

Wholesale sellers may apply to the FERC for MBR authority to sell at market-based rates instead of cost-based rates, by demonstrating to the FERC that it and its affiliates lack, or have mitigated, market power.

Wholesale sellers with MBR authority are required to comply with the following to maintain their MBR authority:

- To demonstrate a continued lack of market power, sellers that control more than 500MW of generation must file Electric Quarterly Reports, as well as updated market power analyses every 3 years.

- If any significant change arises that may affect the seller's qualification for MBR authority, notify the FERC within 30 days.

- Comply with FERC Market Behavior Rules[21]

    1) Unit Operation: Sellers are required to operate and schedule generating facilities, undertake maintenance, declare outages, and commit or otherwise bid supply in a manner that complies with the rules and regulations of the applicable power market
    2) Market Manipulation: Prohibited
    3) Communications: Completeness and accuracy of factual information in communications with the FERC, market monitors, RTOs and ISOs
    4) Price Reporting: Standards applicable to publishers of electricity or natural gas price indices apply.
    5) Record Retention: All information necessary for the reconstruction of the prices charged and reported must be retained for 3 years
    6) Related Tariffs: Non-violation of code of conduct pursuant to Order No. 889.

[20] http://www.ferc.gov/industries/electric/gen-info/mbr.asp

V. State Regulation

A. Revenue Requirement

Price/ revenue regulation is the province of State PUCs. Different states adopt different methods of regulation. The predominant methods are discussed below:

1. Cost-plus regulation

The traditional mode of regulation is **cost-plus regulation**, where the allowed return of utilities is a function of their investment. Under this formula, utilities have been accused of overbuilding, and spending more on power plants, transmission and distribution facilities than would be expected by a cost-minimizing, profit-maximizing enterprise.

In response to the problem of over-investment, several new regulatory concepts have been developed by states:

2. Decoupling or Revenue-Cap Regulation

The use of **decoupling/ revenue-cap regulation** aims to remove the disincentive for utilities to embrace efficiency and reduce consumer usage levels by decoupling the calculation of allowed revenue. A revenue requirement is determined by the state PUC, and rates are established in the traditional way according to the just and reasonable standard. Thereafter, rates are adjusted periodically to ensure that the utility only collects the allowed amount of revenue, even if sales have varied. I.e. If sales decline below the level assumed, rates increase, and vice-versa. Over time, the allowed revenue may be revised to reflect factors such as an overall growth in the number of consumers served.

3. Price-Cap Regulation

Another mode of regulation is **price-cap regulation**. Price-cap regulation stipulates the percentage increase in rates allowed annually, i.e. at 1% below the rate of inflation. Utilities thus have an incentive to constrain expenditures and increase efficiency in order to capture greater earnings. Price-cap regulation is strictly enforced together with service quality standards to ensure that service reliability and quality is not compromised

B. Bundled or Unbundling of Generation, Transmission and Supply Services

The structure of electric utilities varies from state to state. As of September 2010, only 17 states were actively pursuing electricity industry restructuring, i.e. where a monopoly system of electric utilities has been replaced with competitive suppliers. 7 states had suspended deregulation.

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[21] FERC Market Behavior Rules http://www.ferc.gov/whats-new/comm-meet/111303/E-3.pdf

In restructured states, most utilities provide only distribution service while offering an optional or default service for power delivery.

In states where vertically integrated utilities dominate, only bundled service (power supply and distribution) is provided. In such states, PUCs will often grant optional distribution-only direct access rates to allow the industrial user to purchase its power in the wholesale market directly from competitive suppliers, and to pay the state utility only for the cost of transmission and delivery of the purchased power.

C. Retail Choice Programs

Beginning in 1996, individual states began to develop retail choice programs allowing end-use customers of investor-owned utilities to purchase power from alternative suppliers. When the programs were established, many state legislatures and commissions anticipated that after a transition period, most, if not all, customers would be served by alternative suppliers, resulting in lower electric rates.

Today, the promises of retail choice have not been fulfilled for the most part. Only 15 states have active retail choice programs for residential electricity customers. Of those, the participation rate is low in most states, where only a small percentage of residential customers are purchasing power from alternative suppliers[22]. **The most successful programs are those of New York, Connecticut, Massachusetts and Texas**[23].

In most retail choice states, there are few alternative suppliers, and in many cases there are no alternative suppliers serving residential customers. Low wholesale prices are key to the success of retail choice programs, as they allow competitive suppliers to offer attractive prices compared with non-competitive service rates, which typically adjust slowly to changes in wholesale prices.

The Texas Electric Choice program[24]

The Texas state PUC operates an educational and user friendly website that provides comprehensive guidance to customers who wish to switch Retail Electric Providers (REPs). The website includes a section on retail offer comparisons, including contracts and terms, rates, and renewable energy. By entering a zip code, customers will be able to generate a list of REPs on the website for comparison purposes.

Retail choice in Texas has promoted diversity in retail offers. Offers differ in terms of:

- Length of contract period
- Renewable generation portfolio (via an Energy Facts Label)
- Fixed, variable or indexed rates

[22] U.S. Energy Information Administration “Participation Lags in Most Electricity Retail Choice States” May 19 2011: http://www.eia.gov/todayinenergy/detail.cfm?id=1450

[23] U.S. Energy Information Administration “Electricity retail choice is mandated in Texas and growing in three States” May 18 2011: http://www.eia.gov/todayinenergy/detail.cfm?id=1430

[24] Texas Electric Choice website http://www.powertochoose.org; Electric Choice Brochure http://www.powertochoose.org/_files/_pdf/ConsumerGuide_eng.pdf

- Assistance for low income customers
- Rebates for adoption of energy efficiency measures by customers

By educating customers about the various features of retail offers and the criteria upon which they may make their choice of REPs, the Texas PUC has encouraged REPs to compete in the stated areas. This ties in with the overall state policy of promoting energy efficiency and green energy. For example, environment conscious customers will chose an REP with a higher renewable portfolio.

D. Advanced Metering and Dynamic Pricing

Advanced metering allows utilities to measure usage in short intervals by time of day, and to communicate information to and from the customer. This allows (1) utilities to establish more detailed (and potentially more efficient and reasonable) rate designs by accurately matching costs to usage, (2) customers to adjust their usage of electricity based on usage data displayed on the meter. Smart meters can also receive signals from the utility to adjust load based on present customer preferences, thus allowing customers to have greater and more accurate control over their consumption patterns.

Dynamic pricing refers to rates which change in response to changes in market prices for power. Utilities may charge through predetermined time-of-use blocks, or through real-time rates which are provided to the customer a few hours in advance. Real-time rates are often restricted to large industrial customers. Another method is to offer a peak time rebate to customers, as a discount for reducing load at critical times.

Advanced metering and pricing allows both customers and utilities to save money. Customer change their usage based on price signal, whereas utilities avoid the high costs of peaking power plants, additional transmission and distribution capacity. There is controversy over whether utilities should replace all existing meters with smart meters, and state PUCs are progressively addressing the issue. However smart meters have become the norm when installing meters on new buildings or replacing worn-out meters, even if all of their features may not be required for the time being.

E. Integrated Resource Planning

IRP is a long-term plan prepared by a utility to guide future energy efficiency, generation, transmission and distribution investments. Not all PUCs require IRPs to be prepared; of those that do, some accept them without ruling, while some will actively review and grant approval. At present, roughly 30 states rely on IRPs.

IRPs examine forecasted load growth for a utility, and evaluate the least-cost resource mix for the utility and its customers to meet that growth. The costs, reliability and environmental impacts of each alternative resource are evaluated, and the utility will use the IRP to decide what types of resources to acquire and how to manage its programs to achieve the desired results. The IRP may be used by the

PUC to regulate what investments utilities may make, or as a tool to evaluate the prudence of the utility over time.

VI. Competition Regulation

E. Acquisition and Merger Control under the FERC[25]

Approval	**Approval is required for the following transactions:** – Disposition of facilities in excess of $10million in value – Direct or indirect mergers or consolidations involving public utility facilities – Change in control of facilities (except less than 10% in a public utility facility) – Acquisition of securities valued in excess of $10 million in any entity that sells at wholesale/ provides transmission services, by a holding company that owns an entity selling power at wholesale/ providing transmission services – Merger between a holding company that owns an entity selling power at wholesale/ providing transmission services and any entity that sells at wholesale/ provides transmission services, valued in excess of $10 million **Blanket authorization is given for the following transactions:** – Internal corporate reorganizations that do not present cross-subsidization issues – Transactions that do not involve a public utility facility with captive customers – Acquisitions by holding companies of non-voting securities – Acquisitions by holding companies of voting securities if the acquiring holding company owns (directly or indirectly) less than 10% of the voting securities – Acquisitions of foreign utility companies
Review	**1. Expedited consideration** The following transactions qualify for expedited consideration of applications for approval: – Transactions that are not contested, do not involve a merger, and are consistent with FERC precedent – Uncontested transactions involving a disposition of only transmission facilities under the functional control of an FERC-approved RTO or ISO – Transactions that do not require a competitive screen analysis – Internal corporate reorganizations that do not present cross-subsidization issues **2. Competitive Screen Analysis** Applicants must submit a proposal to the FERC outlining the following: – Identify the relevant products (i.e. economic capacity and available economic capacity) and the geographical market in which the effects on

[25] FERC 1996 Merger Policy Statement http://www.ferc.gov/industries/electric/gen-info/mergers/rm96-6.pdf

competition will be analyzed;
- Determine the market shares of all participating firms and the degree of concentration in the market before and after the proposed acquisition;
- Identify the market characteristics that will influence the ability of the combining entities to adversely affect competition, i.e. barriers to entry;
- Benefits of the proposed transaction.

The FERC will then evaluate the magnitude of increases in market power and overall post-transaction concentrations of market power to determine whether the proposed transaction is likely to have an adverse impact on competition. FERC adopts the DOJ/FTC Merger Guidelines as its analytical framework[26].

If the merger passes the competitive screen analysis, it will be presumed to raise no market power concerns.

If the merger does not pass the competitive screen analysis, FERC will engage in a more detailed analysis, considering the benefits of the merger and whether it comports with public interest. This will be conducted through hearings.

Compliance and Mitigation

The guiding principle at this stage is public interest. Applicants must demonstrate that the proposed merger is consistent with public interest. Accordingly applicants must account for changing market structures and the possible effect of the transaction on competitive bulk power markets and effects on ratepayers.

Applicants may submit a mitigation plan to remedy the harmful effects of the merger for approval[27]. Mitigation measures must address FERC's concerns by eliminating the opportunity for the merged company to act anti-competitively; and include measures to ensure compliance with the proposal.

F. Antitrust Enforcement

The FTC and DOJ can review the implications of proposed mergers and acquisitions under the Hart-Scott-Rodino Antitrust Improvements Act of 1976.

Anti-competitive practices may be challenged in court pursuant to the Federal Trade Commission Act, Clayton Act and Sherman Act.

[26] The FTC/DOJ Merger Guidelines were revised in 2010. In March 2011, the FERC has issued a notice of inquiry on whether or not its Merger Guidelines need to be adjusted accordingly, but no further action has been taken so far.
[27] See recent FERC rejection of the market power mitigation plan for the Duke-Progress Merger: http://www.ferc.gov/media/news-releases/2011/2011-4/12-14-11.asp