nrri

Briefing Paper

Implications of EPAct 2005 for State Commissions

The National Regulatory Research Institute

October 2005

Executive Summary

The Energy Policy Act of 2005 (EPAct 2005 or the Act) represents the first comprehensive national energy legislation in 13 years. Major provisions of the Act will affect both the electric and natural gas industries. State regulators will help implement this major piece of legislation as its impact on the structure and performance of the energy public utility industries unfolds.

The purpose of this briefing paper is to examine some of the key issues of state actions, responses, and implications raised by specific sections of the Act. The paper reviews selected provisions of the Act in rough order of importance of state action or attention called for in the Act, with consideration of the complexity of the issues. For a concise summary of EPAct 2005 including all relevant sections, required actions, and deadlines see the NARUC/NRRI Energy Policy Act of 2005 Summary of Titles.

Much has already taken place since the Act's passage Aug. 8, 2005. Readers can go to the web site of the Federal Energy Regulatory Commission (FERC) for the latest rulemakings and notices. Most of the major implications for the states are probably contained in a few key areas:

- Repeal of the Public Utility Holding Company Act of 1935
- Merger review reform
- Transmission siting
- Public Utility Regulatory Policies Act standards

Overall, EPAct 2005 takes steps towards a more national and regional approach to the governance of the electric power grids and markets, while easing restraints on corporate structural borders. States have many opportunities to contribute to new regional organizations, collaborative efforts, and policy making at the federal level. This briefing paper outlines these and some of the other potential state level initiatives that are either required or possible.

Contents

05-16

This briefing paper examines key issues of state actions, responses, and implications raised by the Energy Policy Act of 2005.

INTRODUCTION

The Energy Policy Act of 2005 (EPAct or the Act) is the first comprehensive national energy legislation in 13 years. The Act will profoundly affect both the electric and natural gas markets and regulation. State regulators will help implement this major piece of legislation as its impact on the structure and performance of the energy public utility arenas unfolds.

The purpose of this briefing paper is to examine some of the key issues of state actions, responses, and implications raised by specific sections of the Act. The paper reviews selected provisions of the Act in rough order of importance of action or consideration called for in the Act, with recognition of the relative complexity of the issues. For a concise summary that includes all the relevant sections, required actions, and deadlines see the NARUC/NRRI *Energy Policy Act of 2005 Summary of Titles.* Much has already taken place since the Act's passage Aug. 8, 2005. Readers can go to the web site of the Federal Energy Regulatory Commission (FERC) for the latest rulemakings and notices.

Most of the major Implications for the states are probably contained in a few key areas:

- Repeal of the Public Utility Holding Company Act of 1935 (PUHCA) leaves a gap in regulatory oversight of jurisdictional utilities that are part of larger holding companies, removing a barrier to company consolidation and diversification. Many states are likely to wish to review their authority to regulate holding company affiliates and to strengthen it.
- The Act makes it easier for utility companies to merge, with implications similar to those of PUHCA repeal. States are advised to review and possibly strengthen their authority to review mergers, consolidations, and acquisitions.
- FERC is given new authority to back up state review of siting applications for transmission in a congested area of the country. Many states will be re-assessing transmission congestion in their region(s) and reviewing their regulatory tools and processes for application approval.
- States must decide on several new standards under the Public Utility Regulatory Policies Act of 1978 (PURPA) within a specified time. The standards will help encourage energy conservation, fuel diversity, and efficiency of new generation.

Other areas with implications for state regulation include electric reliability standards, market transparency, siting of liquefied natural gas terminals (LNG), and transmission rate reform.

Table 1 summarizes requirements imposed on the states by the Act and opportunities for fulfilling its goals.

WHAT STATES CAN DO

- **Speak up**…in the many federal forums for comment and discussion
- **Take stock**…of existing state authority, rules, and processes affected by the Act
- **Write**…state laws, commission rules, and commission procedures to fill gaps opened up by the Act and take advantage of opportunities
- **Think regionally**…because the thrust of the Act is towards national and regional regulation
- **Watch out**...for increased wholesale costs that could affect retail customers

TABLE 1
STATE REQUIREMENTS AND OPP0RTUNITIES UNDER EPAct 2005

Topic	What the Act Does	Implications	State Requirements	State Opportunities
PUHCA Repeal	• Repeals the Public Utility Holding Company Act of 1935 • Allows states to monitor utility company financial records	Consolidation and diversification of companies with utility subsidiaries and affiliates	None	• Examine authority to access books and records, review affiliate transactions and prevent cross-subsidies • Supplement existing authority, perhaps with "ring fencing legislation"
Merger Review Reform	• Expedites review of mergers • Requires merger approval if in the public interest, unless cross-subsidization harms a utility	• Consolidation of utility companies • More concentrated wholesale markets	None	• Comment on FERC merger review rulemaking • Review and strengthen state authority to review mergers, consolidations, and acquisitions • Consider conditioning merger approval on "ring-fencing" requirements
Transmission Siting	Allows designation of national interest electric transmission corridors	• Potential increased electricity reliability and cost savings from regional markets • Potential increased cost of transmission expansion	• Consultation with DOE on corridor designation • Approve applications for transmission siting in a designated corridor within one year of filing to avoid FERC preemption	• Take stock of transmission congestion in their jurisdiction • Review siting authority • Make certain that siting applications are not considered filed until complete • Consider steps to expedite the transmission siting process • Consider interstate compacts
PURPA Standards	Requires states to consider and determine five new standards	Improved utility conservation and efficiency	Consider standards for net- and smart -metering, interconnection, fuel diversity, and increased fossil fuel generation efficiency	Encourage efficient time-based rates, distributed generation, and demand-side management
Qualifying Facilities	• Repeals requirement that utilities purchase electricity from qualifying facilities at the utility's avoided cost rate • Prohibits "PURPA machines"	Pass-through of higher wholesale prices that in turn puts pressure on retail rates	None	• Comment to FERC on rule disqualifying "PURPA machines" from being qualifying facilities • Monitor competitiveness of wholesale markets • Apply to FERC to reinstate obligation to purchase at avoided cost, if conditions merit
Electric Reliability Standards	• Establishes Electric Reliability Organization with authority to set and enforce reliability standards • Allows ERO to delegate authority to regional entities • Provides for establishment of regional advisory bodies	Strengthens standards for reliability of the bulk power system	Governors make appointments to regional advisory bodies	• Advise on and monitor development of new regional entities • Coordinate and consult with FERC on oversight and definition of regions • Seek state commission representation on regional advisory bodies

TABLE 1 - ***continued***
STATE REQUIREMENTS AND OPP0RTUNITIES UNDER EPAct 2005

Topic	What the Act Does	Implications	State Requirements	State Opportunities
Market Transparency	• Directs FERC to facilitate price transparency in wholesale markets • Preserves exclusive jurisdiction of Commodity Futures Trading Commission	Improves access to company data on prices, enabling better assessment of impact of wholesale operations and prices on retail markets	None	Collaborate with and encourage FERC to determine whether PJM model and data provide adequate market transparency
Market Manipulation	• Prohibits reporting of false information on wholesale prices or transmission availability • Requires FERC rules to prevent manipulation of wholesale market	Makes prosecution of violations easier because of explicit rules	None	• Ascertain FERC intentions • Evaluate impact of any FERC actions related to retail consumers • Consider additional consumer protection rules or regulations
Economic Dispatch	• Requires regional state-FERC joint boards to study security-constrained economic dispatch • Limits boards' authority to studying issue and reporting to FERC	• Only four joint boards – each board region includes significant state market differences • Lack of consensus within or among joint boards may act as a strong argument for federal advancement of organized markets	Boards have been established and deadline for state representative nominations was Oct 14, 2005	Provide a unified state voice on joint boards that take into account significant regional differences
Siting of Liquefied Natural Gas Terminals	• Gives FERC authority to approve permits for LNG terminals • Requires FERC to consult with state and local representatives on safety and environmental issues • Requires states to complete review of applications within a specified time	Accelerates development of LNG terminals	None	• Actively contribute to FERC certification process. Participate in DOE forums • Contribute to development of emergency response plans • Advise on selection of state safety agency • Conduct safety inspections
Native Load	Entitles utilities to use firm transmission rights to deliver energy to meet native load service obligations	Circumscribes FERC's ability to treat native load priority as unduly discriminatory	None	Helps states protect customers
Transmission Rates	Establishes incentive-based rate treatments of interstate transmission	• May encourage investment • Costs will flow through to retail level	None	Review state cost recovery requirements

REPEAL OF THE PUBLIC UTILITY HOLDING COMPANY ACT OF 1935

Statutory Provisions

EPAct repeals the PUHCA of 1935, replacing it with a much narrower PUHCA of 2005 that provides state and federal agencies with monitoring authority that allows for consumer protection. Sections 1261-1277:

- Provide FERC access to books and records of public utility holding companies and their affiliates and subsidiaries
- Provide state commission access to books and records of a holding company, wherever located, if the commission has jurisdiction to regulate a public utility company in the holding company system
- Exempt from the access requirement holding companies that only hold qualifying facilities (QFs), exempt wholesale generators, or foreign utility companies

Background

PUHCA of 1935 was enacted to address economic inefficiencies and abuses propagated by unregulated holding companies. These included pyramiding, abusive affiliate transactions, joint and common cost misallocation, and corporate financial abuse made possible by the holding company structure.

The major economic issues raised by diversification in an unregulated holding company structure are transfer pricing, unauthorized cross-subsidization, and financial abuse. Diversification can also have an adverse effect on the utility subsidiaries or affiliates due to risk shifting. Congress repealed the PUHCA to support the ability of U.S. companies to diversify in order to attract capital and expand to meet global competitive pressures.

A precipitating factor was the concern of many state commissions and FERC about the implications of the decision by the District of Columbia Circuit Court in Ohio Power Company, 954 F 2d. 779 (DC Cir.) cert. denied, 498 U.S. 73 (1990). The decision precluded FERC from inquiring into the reasonableness of a utility affiliate's decision to make an inter-affiliate transaction from a nonutility affiliate in a registered holding company when the transaction involves goods or services other than electricity (in this case fuel). Instead, the responsibility was given to the Securities and Exchange Commission (SEC). Repeal of the PUHCA remedies this situation by eliminating the SEC's authority over holding companies. FERC will now have access to records of all goods and services.

Transfer pricing occurs when a utility and its subsidiary or affiliate engage in a business transaction with each other. The danger is that the subsidiary or affiliate might charge above-market (and certainly, above cost) prices for goods and services, counting on pass-through from FERC and/or the state commission. Cross-subsidies may arise whenever there are joint and common administrative, capital, or operating costs between a utility and its subsidiary and/or affiliate. Financial abuse is a major problem in unregulated holding companies. Forms of financial abuse can include using the utility's assets or its revenue streams as collateral for upstream or affiliate loans. Under an unregulated holding company structure, the relative risk of affiliates and subsidiaries has an effect on the perceived risk of the utility. Further, if the utility provides an affiliate with an assured or likely customer, then the risk of the affiliate or subsidiary decreases and the perceived risk of

The PUHCA of 1935 addressed economic inefficiencies and abuses of unregulated holding companies.

EPAct repeals the 1935 PUHCA to help U.S. companies attract capital and compete globally.

EPAct gives FERC access to relevant books and records.

A wave of utility diversification can be expected.

States should examine their authority to prevent holding company abuses.

Some states may wish to consider "ring fencing" legislation such as that in effect in Oregon or Wisconsin.

the utility could increase. These are the major potential implications of a change in federal policy to deregulate holding companies. There are other, more subtle, effects as well.

Federal Action

EPAct gives FERC access to books and records that it determines are relevant to costs incurred by a public utility or natural gas company that is an associate company of the holding company and are necessary or appropriate for the protection of utility customers with respect to jurisdictional rates.

FERC Sept. 16 promulgated a Notice of Proposed Rulemaking (NOPR) on rules to implement PUHCA repeal.

Implications

With the repeal of PUHCA, another wave of utility diversification can be expected. Unlike previous waves, this one will be unchecked by federal regulation. Continuing access to utility records allows state commissions and FERC to monitor and protect consumers against abusive affiliate transactions and cross-subsidies through cost misallocation.

State Action

PUHCA repeal imposes no requirements on states, only the capability to monitor jurisdictional utility company financial records. Every state commission should consider carefully examining its authority to access books and records, review affiliate transactions, and prevent cross-subsidies. Some state commissions might wish to consider supplementing their existing authority. It may also be appropriate to propose "ring fencing" legislation at the state level.

Issues for States to Address

States are likely to have varying calculations of the potential costs of holding company abuses versus the benefits to potential economic development of a market where large, diversified companies compete with each other and foreign interests.

When reviewing existing authority for access to books and records, a state should be aware that EPAct 2005 makes state access contingent on the materials being identified in reasonable detail in a proceeding before the state commission. Typical state commission reporting requirements that are met outside a proceeding might not allow access to books and records.

While nearly all state commissions have authority over affiliate transactions and cost allocation, existing legislation to protect a utility affiliate from risk shifting and/or financial abuse from its holding company or nonutility affiliate is not common. Such "ring fencing" legislation may be called for in both restructured states and states with traditional integrated utilities. In a restructured state where there is customer choice for generation supply, or natural gas supply in the case of a gas utility, customers who have both the legal right to choose suppliers and actual alternatives might switch sources of supply to avoid at least some of the higher costs that might result from risk shifting as a result of diversification or financial abuse.

Oregon and Wisconsin offer two good models of "ring-fencing" rules to prevent corporate abuse and if necessary impose a divestiture "hammer" for diversification abuse. Typical provisions of such statutes, and thus issues that states might address, include prohibiting a utility from lending money to or guaranteeing the obligations of the holding company or its nonutility affiliates, limiting nonutility investments to a percentage (such as 25 percent) of the public utility assets, not otherwise impairing the credit of the public utility affiliate, commission pre-approval of utility security issuances, minimum equity requirements, and/or commission approval of mergers, consolidations, or takeovers by anyone owning more than a certain percentage (such as 10 percent) of the utility's outstanding securities. A [presentation by Fitch securities] makes clear that financial credit rating firms view state ring-fencing statutes as desirable, leading to higher credit ratings and lower cost of capital for utilities. A lower cost of capital benefits both utility ratepayers and investors. The advantages and desirability of ring-fencing were also discussed in a [NARUC Staff Subcommittee of Accounting and Finance report].

The following states have regulatory measures that should be adequate to insulate utilities from the activities of nonutility affiliates:

- Wisconsin Statutes 196.795
- Code of Virginia Title 56, Ch. 3 & 4
- Oregon Public Utility Commission Order No. 97-196

Deadlines

None

MERGER REVIEW REFORM

Statutory Provisions

Section 1289 of EPAct amends FERC's merger review authority under Section 203(a) of the Federal Power Act (FPA) to:

- Prohibit a utility, without FERC authorization and for values over $10 million, to:
  - Sell, lease, or otherwise dispose of the whole or any part of its FERC jurisdictional facilities
  - Merge or consolidate those facilities with those of another person
  - Purchase, acquire, or take any security of any other public utility
  - Purchase, lease, or otherwise acquire an existing generation facility used for wholesale of electricity over which FERC has ratemaking authority
- Prohibit a holding company in a holding company system that includes a transmitting utility or an electric utility, without first obtaining FERC's authorization, and for values over $10 million, to:
  - Purchase, acquire, or take any security
  - Merge or consolidate with a transmitting utility, electric utility, or holding company system that includes a transmitting utility or electric utility
- Require FERC to notify the governor and state commission of each state where physical property is located that is affected by a proposed merger
- Require FERC to issue rules implementing its amended merger authority

The FERC must approve a proposed disposition, consolidation, acquisition, or change in control, if it finds the proposed transaction will be consistent with the public interest and will not result in various harmful impacts.

Background

FERC's existing merger policy derives from its Merger Policy Statement in Order

EPAct provides 200-fold increases in the value of property that does not need FERC authorization for a merger - to $10 million from $50,000.

EPAct requires FERC to approve mergers that are in the public interest.

592 in 1996. The statement sets out three factors that the FERC considers when analyzing whether the proposed Section 203 transaction is consistent with the public interest: its effect on competition; its effect on rates; and its effect on state and federal regulation, particularly the potential creation of a regulatory gap. For the most part, the FERC expects state commissions to exercise their own authority to protect state interests.

FERC review is expected to lead to more mergers and acquisitions.

The Act amends the FERC's merger review authority by including generation facilities, which were previously exempt. It also increases the value of property not needing FERC authorization for a merger to $10 million from $50,000.

More importantly, Section 1289 amends FERC's merger authority and requires the FERC to approve mergers if it finds that the proposed transaction will be consistent with the public interest and will not result in cross-subsidization of a nonutility associate company or encumbrance of utility assets for the benefit of an associate company, unless the FERC finds such cross-subsidization is in the public interest.

Federal Action

On October 3, FERC promulgated its NOPR on transactions subject to FPA Section 203. The FERC will provide for the expeditious consideration of completed applications for the approval of transactions that are not contested, do not involve mergers, and are consistent with FERC precedent. These would generally include: (1) a disposition of only transmission facilities, particularly those that both before and after the transaction remain under the functional control of a FERC-approved regional transmission organization (RTO) or independent transmission system operator (ISO); (2) transfers involving generation of a size that does not require screening analysis; (3) internal corporate reorganizations that do not present cross-subsidization issues; and (4) the acquisition of a foreign utility company by a holding company with no captive customers in the United States.

The NOPR proposes that where state commissions *have* authority to act on the transaction, the FERC will not set for hearing the issue of whether the transaction would impair effective regulation by state commissions. The FERC proposes to rely on the application to say whether the state commissions have this authority. Where states *do not* have authority to act on the transaction, the FERC may set for hearing the issue of whether the transaction would impair effective state regulation.

Implications

Due to the repeal of the PUHCA discussed above, FERC and state commissions can expect more mergers and acquisitions, many of which may involve diversified activities within holding company structures. Such activities might have been prohibited in the past under PUHCA. (Recall that a registered holding company was required to operate as a single, integrated system. A registered utility holding company was required to engage in utility-related activities, unless otherwise approved by the SEC.) Both the FERC and those states with authority to review mergers and other similar transactions that fall under FPA Section 203 will face challenges because of the numerous issues that could be raised in merger reviews.

A more concentrated wholesale market may exacerbate existing barriers to competition.

A more concentrated wholesale power market may exacerbate any inherent barriers to market entry and competition. Caution must be exercised even when examining a merger and relying on market concentration indices such as the Herfindahl-Hirschman Index or Lerner

Index. Even when such indices suggest a merger would result in little additional market concentration, the potential for market power abuse may not be as clear. Generation facilities could be strategically acquired and bid into the market to drive up the wholesale power price. In some cases, market manipulating practices, including strategic/collusive bidding of affiliate units, economic withholding, and/or physical withholding can be enhanced by the acquisition of the right strategic mix of generation facilities both inside and outside of constrained locations, including facilities that are "must run" facilities during peak periods.

FERC needs to closely examine any merger or acquisition where generation plant and/or transmission facilities are located in the same region. Further, mergers and acquisitions that result in diversification can have a more subtle effect. Not only is there the possibility of unauthorized cross-subsidization wherever there are joint and common costs, but the relative risk of the diversified venture can adversely affect the cost of capital of the regulated utility, particularly if the venture is more risky than the jurisdictional utility. This is true more times than not when the jurisdictional utility is a load-serving entity.

State Action

None required. Many states should be participating in the FERC NOPR on transactions subject to FPA Section 203.

Issues for States to Address

According to the *NARUC Compilation of Utility Regulatory Policy, 1995-1996,* all but three state commissions at that time had the authority to approve (and hence, condition) mergers and consolidations before they take place. The exceptions were the Florida Public Service Commission, the Michigan Public Service Commission, and the Montana Public Service Commission. Such authority ordinarily gives commissions an opportunity to condition approval of the merger on acceptance of requirements that affiliate transactions be reported, that diversification be limited, and that the utility be subject to ring-fencing from financial abuse and affiliate venture risks shifting. However, this might be a stretch for some state commissions. Traditionally, the public interest standard at the state level has been used to make certain that retail rates are not adversely affected by the merger, or that some of the synergies from the merger flow through to retail customers in the form of lower rates. Many commissions do not have authority to regulate the entry of the utility into nonutility activities, either directly or via an affiliate, and even fewer can actually approve diversification. This means that even where state commissions have authority to review mergers and consolidations, many, if not most, may have no authority or little experience in reviewing the transaction for adverse affects that can happen due to diversification.

Most states have authority to approve, and, therefore, condition mergers, but many have no authority or little experience in reviewing the transaction.

While most states have some authority to review and approve mergers, the traditional state approval process has focused on whether the merger harms the retail ratepayer, for example by resulting in higher rates. Mergers were often approved with requirements that the synergies from the merger be shared with the retail customers. State commissions might, to the extent it is within their authority, consider arming themselves with regulatory tools to make certain that affiliate transactions are reported, cross-subsidies are identified, risk shifting to the utility is prevented, and financial abuse is prevented (such as allowing the utility's

The FERC NOPR presumes commissions will be able to put conditions on mergers.

The core question for states: "Does the commission have enough authority to protect consumers from abuses?"

EPAct authorizes FERC to be a "backstop" for siting transmission in vital congested areas.

assets or revenues to be encumbered or used as collateral for nonutility activities.)

Of immediate concern to the states is that the NOPR, as written, presumes that state commissions with authority to review mergers and consolidation will be able to impose specific conditions designed to protect customers against unfair competitive practices, cross-subsidization, and affiliate abuse. While several state commissions have placed such conditions on approved mergers, it is not certain that it is within the explicit or judicially reviewed powers of all state commissions with merger review authority. The issue for the FERC should not be whether the state commission has review authority over mergers, but the extent of state commission conditioning authority for approving a merger. The core question is, "Does the state commission have sufficient authority to protect consumers from potential abuses?"

As a corollary, state commissions with merger review authority are likely to decide to examine whether they can attach conditions to mergers needed to protect the retail customers (as well as the jurisdictional utility investor, so that there is less risk, a higher credit rating, and a lower cost of capital). Some examples of these types of conditions include reporting and information access requirements; restrictions on intra-corporate transactions that result in direct charges or cost allocations to the utility; a prohibition on the local utility bearing merger transaction costs, transition costs, or premiums; performance standards tied to utility revenues; measures to protect the utility's financial position, particularly dealing with prohibiting the use of utility revenues or assets for collateral for upstream loans or nonutility loans; and code-of-conduct type restrictions to protect individual customer information.

Deadlines

Effective date of merger review provisions – Feb. 8, 2006

SITING OF INTERSTATE ELECTRIC TRANSMISSION FACILITIES

Statutory Provisions

Section 1221 of the Act:

- Instructs the Secretary of Energy to conduct a study of electric transmission congestion within one year, and every three years thereafter, in consultation with affected states.

- Says the resulting DOE report may designate a congested area as a national interest electric transmission corridor, except within the Texas reliability council area (ERCOT).

- Requires DOE and all federal agencies with authority over transmission facilities to enter into a memorandum of understanding to coordinate and expedite review and permitting of transmission facilities

- Authorizes FERC to act as "backstop" and issue permits for construction or modification of electric transmission facilities in a national interest transmission corridor if one of several conditions applies: (1) a state regulator does not have siting authority; or (2) the state regulator does not consider interstate benefits; or (3) the state regulator has withheld approval for more than one year after the later of the filing of an application or the designation as a national interest electric transmission corridor; or (4) the state regulator conditioned its approval in such a manner that there will be no significant reduction in congestion

- Prohibits FERC from exercising its backstop authority over states that belong to an interstate compact, unless the members disagree or take more than one year to reach an approval

Background

Transmission capacity has substantially lagged behind new generation. Indeed, investment in transmission has been falling for the last 30 years. One explanation offered by some industry observers for the lack of transmission investment is the difficulty in siting new transmission to support the growth of regional electricity markets capable of wheeling electricity across long distances from generation to consumers. Under this view, transmission lines that might benefit the larger market might not receive siting permission from states which do not judge the proposed line to be of enough benefit to that particular state. The Act's new federal "backstop" siting authority is intended to resolve this tension between regional benefits of additional transmission capacity and costs that fall on an individual state.

Federal Action

The study by DOE will examine transmission congestion. Following an opportunity for comment from the states and other parties, DOE will issue a report designating certain areas as national interest transmission corridors. The selected corridors are likely to include (but are not limited to) the same pathways identified in DOE's National Transmission Grid Study of 2002. Issuance of permits by FERC will await the results of the new DOE study.

It is important to note that the existing level of congestion is not the only relevant criterion for the designation of national interest corridors. The Act allows designation if a corridor would somehow enhance U.S. energy independence, national defense, homeland security, or, most broadly, would be in the interest of national energy policy. DOE may also consider the prospects for economic growth, which could include the opportunity for access to low-cost power that could result from increased transmission capacity. This criterion makes it possible for DOE to designate any path from lower cost (often existing base load units) to higher cost areas, including many load pockets, as a national interest corridor. Thus, there might be many possible additional national interest transmission corridors beyond those necessary to relieve existing congestion.

Other criteria besides congestion are enforcement of energy independence, national defense, or homeland security; prospects for economic growth; and support of national energy policy.

FERC will have to develop a transmission permitting process since it does not already have one, and the Act does not specify a deadline for FERC to issue such rules. However, FERC is required to allow states and other interested parties to present their views and recommendations in the course of any siting proceeding. As with FERC's siting authority over gas pipelines, 15 USC 717f. FERC would be required to conduct a National Environmental Policy Act (NEPA) review before issuing any transmission siting permit. Such a review would not usually be triggered in the course of a state-level siting process unless the jurisdiction of a federal agency were involved, such as if the line were crossing federal lands.

The Act specifies that DOE is the lead agency to coordinate federal action on all siting applications that require federal authorization or review, which would include siting applications that ended up at FERC. Whether at the federal or state level, environmental reviews can extend the length of the permitting process. Therefore, DOE's authority to coordinate and expedite the federal authorization process, together with its responsibility to prepare the single environmental review document to be used for all federal decisions, gives DOE an important role alongside FERC in the federal siting process.

States are urged to look at the model transmission siting statute of the National Conference of State Legislators.

Implications

The principal reason that new transmission investments have declined over the years might not be because of state transmission siting denials or delays, but rather the lack of financial incentives for building transmission. Nevertheless, the establishment of a FERC transmission siting backstop should end the debate over whether state transmission siting processes create an undue burden that is a barrier to interstate transmission capacity that could result in regional benefits, such as greater reliability as well as cost savings from generation markets with a larger geographic scope.

State commissions might wish to consider one-stop shopping, a lead agency approach or even an interstate compact to expedite transmission siting.

State Action

States will wish to review existing siting authority and may wish to consider new institutional relationships and processes that allow a more active role in transmission siting.

Issues for States to Address

The National Conference of State Legislators offers a Model Statute for regional coordination in planning and siting of electric transmission lines. States are urged to consult this document. DOE's congestion study is to be conducted in consultation with the states, so states should prepare comments on which paths they consider to be overly congested and which paths should not qualify as national interest corridors.

With the exception of Texas, which is exempt from the siting provision, the first step for state commissions is to take stock of transmission congestion issues in their jurisdictions and estimate the likelihood of a "national corridor" designation. The states most likely to be conduits for new transmission lines and facilities are under the most pressure to take anticipatory action. They will wish to review existing siting authority, to make certain that it is sufficient to allow them to site transmission facilities in national interest electric transmission corridors. Specifically, a state commission should review whether it can consider the interstate benefits expected to be achieved by proposed transmission facilities and whether non-jurisdictional transmission utilities can apply for siting. States should make certain that an application is not considered filed until it is complete, so that the commission or other siting authority has a full year to make a determination. For example, an application would not be considered filed until environmental review or some other prerequisite is completed.

State commissions might wish to consider the desirability for either one-stop shopping or a lead-agency approach to expedite the transmission siting process so that the process can more readily be completed within one year of the filing of an application. The one-stop shopping approach of the Ohio Power Siting Board has been considered a model for expediting a state siting process. It streamlines and coordinates the process, while not neglecting individual environmental and other approvals.

Three or more adjoining states may establish an interstate compact, subject to the approval of Congress, forming regional transmission siting agencies that will carry out state siting responsibilities and facilitate siting. State commissions might wish to explore with their neighbors the advantages to forming regional compacts on transmission siting.

The principal advantage for state commissions forming an interstate compact is that doing so would remove several of the conditions that can lead to the FERC backstop:

- Whether the individual state has the authority to site the facilities
- Whether the state can consider expected interstate benefits
- Whether the applicant does not qualify for a permit

The regional siting agency which is established by compact must have the authority to review, certify, and permit siting of transmission facilities, including facilities in national interest electric transmission corridors (other than facilities on property owned by the United States). Any compact that is entered into that establishes such a regional transmission siting agency must still get approval from Congress.

The principal disadvantage to states might be the loss of sovereignty over the transmission siting process, although the prospect of federal preemption because of a FERC backstop already severely limits state sovereignty. Additionally, a regional transmission siting agency can do a better job of measuring the regional benefits of siting new transmission facilities, while taking into account the local burdens and costs to those areas where the transmission line is sited. Indeed, the prospect of voluntary regional transmission siting authorities has been endorsed by NARUC and the National Governors' Association as a result of a "best practices" study.

The principal challenge for states setting up such an authority would be to agree on which states should form a particular authority. Wherever possible, it might make sense to have larger regions, so long as the compact is allowed (by Congress) to have flexible voting rules whereby only those states burdened by the siting of the transmission lines or receiving immediate benefits participate in the siting/voting process. For example, a regional transmission siting agency might form along the boundaries of the Organization of MISO states, but when a line is proposed, only those states along the proposed line or receiving a benefit from power from the line would participate.

It will be challenging for such a regional agency to work with and coordinate the approvals of state environmental agencies. It is also worth noting that a consensus-building process might be used to reach agreement, with the FERC backstop as an alternative to reaching a consensus resulting in an approved transmission line. The FERC backstop is still in effect if the compact is in disagreement and there is no approval after one year or if the compact's approval is conditioned so that transmission congestion will not be significantly reduced, or the line is not economically feasible.

Time is limited for states to review their authority and decide on strategies. If they wish to be active forces in resolving the country's most serious congestion problems, they should take the necessary actions by next summer.

If states wish to be active forces in resolving the country's most serious congestion problems, they should act no later than next summer.

Deadlines

- Designation of national transmission corridors – Aug. 8, 2006
- Federal agency memorandum of understanding to coordinate review and permitting of transmission facilities – Aug. 8, 2006
- FERC review of applications – any time after Aug. 8, 2006

EPAct enacts five new standards to encourage efficient use of energy, including demand-side approaches, at a time of rising prices.

PURPA STANDARDS

Statutory Provisions

Sections 1251, 1252, and 1254 (Subtitle E) of EPAct 2005 amend Sections 111(d) and 112 of the PURPA to require states to consider and determine standards for:

- Net metering
- Smart metering
- Interconnection
- Utility plans to minimize dependence on one fuel source
- Utility 10-year plans to increase the efficiency of fossil fuel generation

Background

Enacted in 1978, PURPA promoted change in public utility regulatory policies at the state and federal levels. PURPA is intended to encourage (1) conservation of energy, (2) optimization of electric utility facility and resource efficiencies, and (3) equitable rates to electric consumers. Title I sets out regulatory standards for state commissions to consider and then determine whether they are appropriate to implement.

Almost full responsibility for consideration and determination of the standards falls on the states.

The 2005 amendments add five new PURPA standards to address current conservation and efficiency needs. In recent years, most of the additions to generation capacity in the United States have been peaking units fired by natural gas, a clean source and until recently a cheap one. Increasing gas prices and concerns about future sources of supply of gas and other fossil fuels, however, persuaded Congress to encourage development of renewable energy, rather than fossil fuels, and utilities to minimize dependence on a single fuel. The new PURPA standards for state commission consideration reflect these concerns.

Federal Action

Almost full responsibility for the implementation of the consideration and determination of the five new PURPA standards falls on state commissions. The Secretary of Energy, however, may intervene in any state ratemaking or appropriate regulatory proceeding.

Implications

The Act contains a number of amendments to PURPA but the most important for the states are the consideration of the five PURPA standards dealing with net metering, smart metering, interconnection, fuel source diversity, and fossil fuel plant efficiency discussed in this section of the briefing paper; and the amendment regarding the prospective repeal of the mandatory QF purchase requirements discussed below. The PURPA amendments encourage efficient use of energy resources, including demand-side resources, at a time of rising prices.

States are required to consider specified ways to encourage users to connect small scale generators to the electricity grid with advanced or net metering capabilities that would enable excess electricity delivered to the grid from the generator to offset the electricity drawn from the grid by the user at other times and thereby reduce the user's bill. This would create an additional economic incentive for energy users to become energy producers.

State Action

States must consider and determine whether each of the five PURPA standards is appropriate.

Issues for States to Address

Scheduling and Completing the Formal Process

The process for developing standards is formal and likely to be relatively resource intensive. State commissions are to consider the standards after public notice and a hearing. The determination must be in writing, based upon evidence presented, and available to the public. Some time and effort can be saved if the state has already done some groundwork. Prior state actions can substitute for the consideration and determination requirement, if before Aug. 8, 2005, the state has implemented the standard (or a comparable standard) for the utility; the state commission has conducted a proceeding to consider implementation of the standard (or a comparable standard); or the state legislature has voted on the implementation of the standard (or a comparable standard). However, in the case of the smart metering standard, consideration or state legislation must have occurred within the three years prior to enactment of EPAct 2005. States will need to get started on their proceedings in a timely manner. A state's failure to comply with the standard setting requirements triggers PURPA Section 112(c) which requires that the consideration and determination be undertaken in the first rate case proceeding commencing after the deadline.

Flexibility

Though states must consider the standards, nothing prohibits a state commission from determining that it is not appropriate to implement a standard pursuant to its authority under otherwise applicable state law. State commissions, to the extent consistent with otherwise applicable state law are to implement any standard that they consider to be appropriate, unless they say in writing the reasons for declining to do so.

Net Metering Standard

The net metering standard requires that each electric utility make available upon request net metering services to any electric consumer that the electric utility serves. Because the prior action exception might apply if a state took action before EPAct 2005, some of the 40 states that already require net metering might not have to make any changes. However, in many states, net metering is limited (for example, by utility volumes, customer class, or application). To determine whether implementation of the net metering standard encourages equitable rates to electric consumers, state commissions will need to consider the value of avoided generation, transmission, and distribution made possible by distributed generation. State commissions will also need to consider the cost of net metering and whether it is equitable for that cost to be borne by others or by the net metering customer. In other words, state commissions need to consider whether implementation of the net metering standard might create cross-subsidies between customers, particularly if net metering is done on meters that are not time-based, using rate schedules that are not time-based. State commissions could exempt utilities under their jurisdiction from net metering that results in cross-subsidies.

Smart Metering Standard

The Act requires each electric utility to offer each of its customer classes, and provide individual customers on their own request, a time-based rate schedule. Prices in a time-based rate schedule change to reflect variations in the utility's costs of generating and purchasing electricity at

The process for developing standards is formal and likely to be resource intensive.

Some of the 40 states that already require net metering may not have to make any changes.

Time-based rates have been successfully implemented across the country.

The deadlines for determination and implementation of the smart metering standard are poorly aligned.

The interconnection standard will allow consumers with onsite generation to connect to local distribution facilities.

Each electric utility must develop a plan to minimize dependence on a single fuel source.

the wholesale level. Smart metering rate schedules enable the electric consumer to manage energy use and cost through advanced metering and communications technology. Several nonexclusive examples of smart metering are provided in the Act: time-of-use pricing, critical peak pricing, real-time pricing, and credits for peak load reduction agreements. In looking at the smart metering standard, state commissions can rely, in part, on previous work and experience with time-of-use and demand-response rates. For example, time-based rates have been successfully implemented in programs around the country, including Georgia Power in Georgia, Duke Power in the Carolinas, Niagara Mohawk in New York, Gulf Power in Florida, and the Salt River Project in Arizona. California has recently concluded its successful critical peak pricing pilot program.

Time-based rates should reflect the benefits of avoiding generation, transmission, and distribution costs due to consumers switching from peak hours. These benefits would be measured by determining the marginal cost savings of these functions. Customer load shifting from or conservation on peak relieves transmission congestion at a time of system peak and might make the importation of lower cost generation possible. Reviewing and deciding on a standard requires consideration of the costs and benefits of such programs. Most of the costs are in the form of metering and capital expenditures. These costs are likely to be borne by the customer. In deregulated markets the advanced metering might be offered by the marketer or perhaps by the wires company with a marketer offering the time-based rate schedule. Each state commission will need to customize its standard to its own regulatory situation.

The deadlines for determination and implementation of the new smart metering standard come together in a somewhat awkward fashion. For smart metering, state commissions have 18 months to conduct an investigation and issue a decision on whether it is appropriate to implement the smart metering standard, the first step in a two-part process. This deadline is Feb. 8, 2007. The utilities are to begin offering time-based rate schedules and providing time-based meters beginning on that same date. Having the commission's decision and the utility's implementation on the same date is not realistic unless the utility plans implementation of the commission decision before it is issued. While the February 2007 deadline for the states applies to the investigation and the offering of time-based rate schedules and providing time-based meters, the remainder of the standard is not required to be determined until Aug. 8, 2007. The remaining part of the standard would require consumers of a third-party retail electric marketer (where allowed by a state) to be entitled to the same time-based metering and communications device and service as the utility's own retail consumer.

Interconnection Standard

Each electric utility must make interconnection service available on request to any electric consumer that the utility serves. The interconnection service to be provided is service to an electric consumer under which an on-site generation facility on the customer's premises must be connected to the local distribution facilities. This will allow consumers with onsite generation, sometimes called distributed generation, to connect to the local distribution facilities. Interconnection services should be offered based on IEEE Standard 1547. The standard provides that agreements and procedures will be established whereby the services offered promote the best practices of interconnection for distributed generation, including the Model Code adopted by NARUC.

Fuel Sources Standard

EPAct requires each electric utility to develop a plan to minimize dependence on one fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies. It would be difficult for some electric utilities that are heavily reliant on one fuel source to greatly diversify because the fuel source might be a least-cost source indigenous to the area. It is nevertheless possible for nearly all utilities to reduce their dependence on one source by encouraging renewable technologies, such as photovoltaic solar panels or wind energy, as well as by buying wholesale energy from utilities with other fuel sources. Commissions will want to consider both the limitations and advantages of diversification for their local utilities.

Fossil Fuel Generation Efficiency Standard

This standard would require each electric utility to develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation. Implementation of the fossil fuel generation efficiency standard might accelerate the retirement of pre-Clean Air Act coal plants, which over time might be replaced with either supercritical pulverized coal generation or integrated coal gasification combined-cycle generation, the latter possibly using geologic carbon sequestration. Increasing the efficiency of fossil fuel generation could increase the rate base and increase rates in the short run if traditional ratemaking methods are used. If this standard is implemented, a state commission might consider such options as sale-and-lease-back, or construction work in progress (CWIP) to change the cost recovery of capital so that the increase fuel efficiency of the plant might result in rates that are lower in both the short run and long run. Sale-and-lease-back has an advantage over CWIP in that it does not provide for cost recovery until a plant is used and useful.

Increasing the efficiency of fossil fuel generation could increase utility rate bases and rates in the short run. Commissions might consider options like sale-and-lease-back or construction work in progress.

Deadlines

Schedule for Consideration and Determination of New PURPA Standards

	By Aug. 8, 2006	By Aug. 8, 2007	By Aug. 8, 2008
Net metering		Begin consideration	Make determination
Smart metering	Begin consideration	Make determination	
Interconnection	Begin consideration	Make determination	
Fuel sources standard		Begin consideration	Make determination
Fossil fuel generation efficiency		Begin consideration	Make determination

Under EPAct, utilities no longer have to purchase elecricity from QFs at avoided cost.

“PURPA machines” are now prohibited.

State commissions will have insights to share with FERC on whether a utility’s obligation to sell to a QF should be discontinued.

QUALIFYING FACILITIES

Statutory Provisions

Section 1253 (Subtitle E) of EPAct 2005 amends PURPA Section 210 to:

- Prospectively repeal the requirement that utilities purchase electricity from QFs such as cogeneration and small renewable facilities at the utility’s avoided cost rate. The repeal is effective for all new QFs and for new contracts.
- Requires FERC regulations to ensure that an electric utility that purchases from a QF in accordance with any legally enforceable obligation entered into or imposed pursuant to Section 210 recovers all prudently incurred costs associated with the purchase

Background

One intention of PURPA was to encourage the development of cogeneration and small renewable power facilities. Section 210 of PURPA deals with the avoided cost, purchase, and sale obligations of utilities in their dealings with QFs.

The repeal of utility sale and purchase obligations for QFs is meant to reflect that, where there are adequately established wholesale markets, new cogeneration and small renewable power production no longer need preferred status for sales and purchases.

Federal Action

<u>Termination of Mandatory Purchase Obligation</u>

FERC is to issue and enforce regulations to ensure that an electric utility that purchases energy or capacity from a QF will recover all prudently incurred costs. To terminate the mandatory utility obligation to purchase, FERC must find that the QF has nondiscriminatory access to any of the following:

- Independently administered, auction-based, day-ahead and real-time wholesale markets for the sale of energy and wholesale markets for long-term sales of capacity and energy
- Transmission and interconnection services provided by a FERC-approved regional transmission entity and administered pursuant to an open access transmission tariff that affords nondiscriminatory treatment to all customers and competitive wholesale markets that provide a meaningful opportunity to sell long-term and short-term capacity and long-term, short-term, and real-time energy to buyers other than the host utility to which the QF is interconnected
- Wholesale markets for the sale of capacity and energy that are at a minimum of comparable quality to the markets just described

The obligation of the utility to sell to the QF terminates for new contracts if FERC finds that competing retail electric suppliers are willing and able to sell and deliver energy to the QF and the electric utility is nor required by state law to sell energy in its service area.

<u>Redefinition of Qualifying Facilities</u>

FERC is required to issue a rule that any new QF seeking to sell electric energy pursuant to PURPA Section 210 not be a so-called “PURPA machine.” PURPA machines fit the technical definition of QFs, but they were designed primarily to sell electricity to a utility. Their primary or fundamental output was not for an industrial, commercial, or institutional purpose. An example of a

PURPA machine is a power generation facility where the waste heat is used in a greenhouse. Now, the electrical, thermal, and chemical output of a new qualifying cogeneration facility must be used fundamentally for industrial, commercial, or institutional purposes rather than the sale of energy to an electric utility. Ownership limitations for QFs are also eliminated, which will allow utilities to have a majority equity interest in QFs.

EPAct 2005 repeals the requirement that utilities purchase electricity from QFs at the utility's avoided cost rate for new contracts as well as new QFs that have access to competitive wholesale electricity markets.

On Oct. 11, 2005, FERC promulgated a NOPR on rules to implement this section of the Act.

State Action

None required.

Issues for States to Address

Involvement in FERC Proceedings

Because the determination of whether there are adequate wholesale markets to allow the repeal of the mandatory purchase obligation is made by FERC, state commissions will want to be very involved in such FERC proceedings. State commissions will have special insights to share with FERC as to the availability of retail electric suppliers and the requirements of state law and thus special knowledge as to whether or not a utility's obligation to sell to a QF should be discontinued.

Monitoring Competition

Many state commissions will find it advisable to closely monitor the competitiveness of wholesale markets to assure that purchase obligations, whether imposed by statute or entered into by contract, are the results of competitive wholesale markets. This is particularly important as there will no longer be ownership restrictions on QFs and such purchases might be at less than arm's length. (Normally there is no presumption of prudence for affiliate transactions.) Further, state commissions may apply to FERC for an order reinstating the host utility's obligation to purchase at the host utility's avoided cost if the conditions of an adequately competitive wholesale market no longer exist.

Automatic Pass-Through

The requirement that a utility recover prudently incurred costs of purchases from a QF may result in a guarantee of automatic pass through of such purchases. This is a significant change. It could impact state purchase power adjustment clauses. State commissions might petition FERC in its rulemaking to provide for the potential of a prudence review to assure that purchases from a QF are prudently incurred, particularly in the case where the purchase is an affiliate transaction. While FERC is relatively inexperienced in conducting such prudence reviews, state commissions are well versed in them. A prudence review of such a purchase can properly balance the need to assure the utility of proper cost recovery and the need to protect the utility's retail ratepayer from imprudently incurred costs, for example from abusive affiliate transactions.

The requirement that a utility recover prudently incurred costs of purchases may result in a guaranteed pass-through.

Section 1211 will strengthen the systemization, applicability, and enforcibility of standards to improve the reliability, of the nation's power grid.

To speed up establishment of mandatory reliability standards, FERC proposes that the applicant ERO submit proposed standards at the same time it applies.

Deadlines

FERC rule disqualifying so-called "PURPA machines" from being QFs – Feb. 4, 2006

ELECTRIC RELIABILITY STANDARDS

Statutory Provisions

The Act establishes an Electric Reliability Organization (ERO) under FERC's jurisdiction. Section 1211:

- Gives the ERO the authority to set and enforce mandatory reliability standards for all users, owners, and operators of the bulk power system
- Requires the ERO to file proposed standards with FERC for its approval
- Preserves the authority of a state to ensure safety, adequacy, and reliability of electric service, so long as the state reliability standards are not inconsistent with the ERO's standards
- Requires that FERC rules establishing the ERO include, among other matters:
    - Procedures governing delegation of authority to a "regional entity" for the purpose of proposing reliability standards and enforcement of compliance
    - Procedures to establish "regional advisory bodies" of governors' appointees to advise the ERO, regional entities, and FERC on regional issues

Background

As part of the movement to create functioning wholesale electricity markets, support for mandatory reliability standards for operating the transmission grid grew over the last several Congresses. The support grew even stronger after utilities' failures to abide by voluntary reliability standards contributed to the widespread blackout in the Midwest and Northeast in August 2003. NARUC has supported mandatory standards.

Federal Action

FERC issued a NOPR on Sept. 1, 2005, on certification of the ERO and procedures for the establishment, approval, and enforcement of electric reliability standards. Several states and NARUC filed comments prior to the Oct. 7, 2005, deadline. The Act provides for a two-step process: establishment of an ERO followed by setting mandatory reliability standards. The NOPR, however, allows ERO applicants to simultaneously submit proposed reliability standards which, in FERC's view, would accelerate the establishment of reliability standards.

DOE and the Federal-Provincial-Territorial Electricity Working Group of Canada have jointly developed and endorsed bilateral principles upon which they say the establishment and functioning of the ERO should be based for the latter to effectively function across the border.

Implications

Stronger Reliability Standards

Section 1211 will strengthen the systemization, applicability, and enforceability of reliability standards to improve the reliability of the nation's power grid. The standards apply to all users, owners, and operators of the bulk power system, that is, the facilities and systems operating as part of the country's interconnected transmission network, excluding Alaska and Hawaii. New York is permitted to establish its own reliability rules as long as they do not lessen reliability outside the state. The ERO standards applying to cross-border regions would also require recognition by Canadian or Mexican authorities and would therefore require harmonization through bilateral consultations. The ERO will be governed by an independent board with due representation of stakeholders. All reliability standards proposed by the ERO must be approved by FERC before they can take effect.

The new federal enforcement authority is intended to increase the incentive to comply with standards. In order to meet the new standards some existing infrastructure may need to be modified. ERO and FERC do not have the authority to order the construction of new generation or transmission capacity. The standards only give guidance for investment in the processes and facilities that may result in actual improvements in reliability of the grid.

Requirements to Become the ERO

Any person can apply to FERC for certification as ERO within 60 days of the FERC ruling. The ERO applicant must demonstrate that it has: (1) the ability to develop and enforce reliability standards that are adequate for the bulk power system; (2) rules assuring its independence from users, owners, and operators while providing for fair stakeholder representation on its board, committees, and subcommittees to enable balanced decision-making; (3) rules for allocating dues, fees, and charges equitably among end users for all its activities; (4) fair and impartial procedures for enforcement of reliability standards through imposition of monetary and non-monetary sanctions and penalties; (5) rules that provide opportunity and due process for public comment and balance of interests in developing reliability standards; (6) identified the appropriate steps needed to gain recognition in Canada and Mexico after being certified by FERC. FERC would require the ERO to reapply periodically to maintain its certification. The North American Electric Reliability Council (NERC) would appear to meet most of these requirements, but will have to apply to FERC for certification. There is no known competition to NERC.

Consolidation of Organized Markets

The reliability provisions of the Act have the important potential to facilitate further consolidation of control areas and organized markets, which may lead to redrawn regional boundaries encompassing multiple regions within the same interconnection. For example, the Northeast and the Midwest now fall under four regional reliability councils (RRC) – MAAC, MAIN, MRO, and ECAR. Integration into one regional entity is plausible. FERC also expects a greater level of uniformity among reliability standards approved for regional entities not organized on an interconnection-wide basis. Additionally, RTOs operating in multiple regions will seek greater uniformity of reliability standards within an interconnection.

The reliability provisions of the Act may facilitate further consolidation of control areas and organized markets. This could lead to redrawn regional boundaries encompassing multiple areas in the same interconnnection.

Influence of Regional Entities

The regional entities established by Section 1211 may have quite a bit of influence. FERC is required to establish rules to allow the ERO to delegate its authority to regional entities. The selection of the regional entities appears to have been left with the ERO, although the FERC NOPR asks whether it should specify the size, scope, configuration, and authorities of the regional entities as well as their relationships to the ERO. The regional entities will have to meet the same criteria as the ERO, referred to above, and be governed by independent and/or balanced stakeholder boards. Any

The Act may reduce state ability to set and enforce standards in its jurisdiction and place more responsibility with the federal government.

delegation agreement between the ERO and the regional entities must be filed by ERO and approved by FERC before it can take effect. A delegation agreement must demonstrate that it promotes effective and efficient administration of bulk power system reliability. FERC seeks comments on what should constitute "effective and efficient" in this context.

Recognition as a Regional Entity

The NOPR allows any entity seeking a delegation agreement with the ERO but unable to reach one within six months, to apply directly to FERC for the ERO's authority to enforce reliability standards in the region to be assigned to it. Thus, while it is probably more likely that an existing RRC (or combination of RRCs) would receive FERC approval as a regional entity, formation of new entities different from the RRCs is not precluded. However, in order to be approved by FERC, a new regional entity will need to develop all the operating rules and procedures and be able to demonstrate some experience in this area.

Regional Standards

State authority "not inconsistent with" ERO standards is preserved.

The regional entities may propose variations to the ERO standards that do not detrimentally affect the system outside the region. However, those variations, if approved by FERC, would constitute ERO standards applicable to the given region, and not regional entity standards. The standard applied by FERC in reviewing proposed reliability standards is "just, reasonable, not unduly discriminatory or preferential, and in the public interest." The ERO and FERC are to presume (in a legally rebuttable sense) that a regional standard proposal by a regional entity organized on an interconnection-wide basis should be approved. The rules for delegation to a regional entity may provide that FERC can assign the ERO's authority to enforce certain mandatory reliability standards.

Regional Advisory Bodies

In addition, FERC is to establish regional advisory bodies if two-thirds of states in a region that have more than one-half of their load served within the region so request. Members of the boards are appointed by the governors of the relevant states, and are to advise the ERO, FERC, or regional entity on matters such as the applicability of proposed standards, fees, and governance issues. Regional advisory bodies may also perform other functions at FERC's request. FERC says it may give deference to the advice of a regional advisory body if it is organized on an interconnection-wide basis.

Enforcement

The ERO and the regional entities will have the authority to impose monetary and non-monetary penalties for violation of reliability standards. FERC will also have the ability to impose civil penalties on the ERO and the regional entities for violation of the FPA or failure to follow a FERC order. In the NOPR, FERC views the ERO and the regional entity provisions of the EPAct 2005 as modeled on the self-regulatory organization (SRO) provisions of federal securities law, and under those provisions the SEC can also impose monetary and non-monetary penalties on the SRO board members. FERC is seeking comments on whether such provisions should be included in the FERC order.

State Action

There are no required actions. Many states may wish to:

- ***Coordinate and consult with FERC, especially to influence the definition of their oversight authority and the definition of regions that will ultimately determine the role of regional entities***
- ***Seek appointment by their governors to the regional advisory bodies***

Issues for States to Address

Ability to Set Standards

Although Section 1211 has no formal impact on existing state authority, the indirect effect may be to reduce state ability to set and enforce standards within its jurisdiction and place more responsibility at the level of the federal government and organizations that encompass more than one state. This may, however, have the beneficial effect of greater consistency within a given region, leading to greater reliability that states want.

The Act preserves state authority over reliability when it is "not inconsistent with" ERO standards. Upon complaints of inconsistency between a state's action and an ERO standard, FERC is left to determine whether inconsistency exists and may stay the state's action until issuing a final order. It may therefore be necessary to assess any potential conflicts between a state action and an ERO standard and resolve those before the action is taken. State commissions should continue to exercise their authority to ensure safe, adequate, and reliable service.

Standard Setting

When standards are set too high or the perceived risk of enforcement penalties is too high, utilities may over-invest in new facilities. Although the focus of attention on reliability issues tends to be on too little reliability, the opposite result of over-investing needs to be considered as well. There is a lack of sufficient recent research on the consumer's view of reliability – that is, how much reliability end users really want and how much are they willing to pay. Research on this topic might provide interesting regional variations in the perceived benefits of reliability standards.

Sufficient recent research is lacking on the consumer's view of reliability.

State commissions may also wish to comment on how FERC should operationalize their proposed criteria – "just, reasonable, not unduly discriminatory or preferential, and in the public interest" – in the context of reviewing a proposed reliability standard.

Regional Interests

State commissions will wish to advise and closely monitor development of the new regional entities called for in the Act. These organizations might supplement or perhaps subsume some existing state responsibilities. State commissions should also consider how standardized the delegation agreement between the ERO and a regional entity should be and advise FERC accordingly before the final rule is issued. Having the ability to tailor these agreements to suit each region may be helpful in accommodating regional specifics.

State commissions will wish to advise and closely monitor development of the new regional entities.

Formation and Operation of Regional Advisory Bodies

Regional advisory bodies, if they decide to form as set out in the statute, use the same boundaries as regional entities. That is, the configuration of the newly formed regional entities will determine the composition of the regional advisory bodies. However, if a group of states can demonstrate that a new regional entity configuration will be of significant advantage

States are likely to want strong advocates of their interest appointed to the regional advisory boards.

The Act requires FERC to improve price transparency in wholesale markets.

and there are not yet regional entities in existence, state commissions within a region might early on decide to influence the boundaries of what might become a regional entity. In many cases, regional entities may form along the boundaries of the current regional reliability councils. In reaching the decision to form a regional advisory body, states (ideally state commissions) would need to negotiate in advance the procedures and voting rules of the advisory body. The step-by-step process might be somewhat similar to that used in the formation of the Organization of MISO states. The use of consensus-building procedures might be useful, particularly if a super-majority or unanimity is required to vote.

International Cooperation

States in the cross-border regions may need to consider the implications of a remand of a reliability standard by the Canadian or Mexican authorities that has already been accepted by FERC. The bilateral principles cited above call for extensive consultations and resolution of all issues before revisions are presented to FERC for approval. Cross-border, inter-agency cooperation may be helpful in avoiding such situations.

The bilateral principles call for the separation of the regional entities from the regional transmission system operators such as ISOs and RTOs because of the inherent conflict of interest between the operator and the enforcer. There are two RTOs in the United States – Southwest Power Pool (SPP) and ERCOT – that have also been regional reliability councils. It is very likely that these two entities will also become the newly defined regional entities and ERCOT will also qualify as an interconnection-wide regional entity. The state regulators, because of their local knowledge, are in a better position than FERC to determine how these functions could be separated. NARUC in its comments on the FERC NOPR proposes that the present arrangement used by SPP to separate their reliability council function from the RTO function may be considered an option.

The bilateral principles also specify that membership in the ERO should not be a condition for participation in the ERO's reliability development process. This provision, if included in the FERC rule, might allow greater state and public input in the standard development process.

Participation in Regional Advisory Bodies

States are likely to want to secure appointment of strong advocates of their interests to the regional advisory bodies, particularly since the regional entities (that the regional advisory bodies will advise) will consult with the Secretary of Energy as to what geographic areas should be designated as national interest transmission corridors under Section 1221(a) of the Act (see above). The FERC NOPR leaves the role of the regional advisory bodies somewhat open by defining one of their functions as "any other responsibilities requested by the commission." Thus FERC could allow states within a region greater influence on decisions affecting their region.

Nothing in the Act seems to restrict state agency staff from holding positions on the boards of directors of the ERO and the regional entities. A seat on the board provides greater influence over decisions; however, it could weaken a state's position somewhat in a contested proceeding before FERC concerning a matter between the ERO/regional entity and the state.

Redrawing Regional Boundaries

State regulators should foresee the possibilities of redrawing regional boundaries opened up by the Act and seek the authorities they need should a merger take place. FERC says that it will not defer to the ERO or a regional entity with respect to the effect of a reliability standard on competition. The state regulators will presumably wish to ensure that reliability is the paramount consideration.

Deadlines

- Final FERC rule implementing the new reliability provisions – Feb. 6, 2006
- No timeline for states to petition for the creation of the regional advisory bodies, nor are they under any other timelines under this section

ELECTRICITY MARKET TRANSPARENCY

Statutory Provisions

Section 1281 of the Act requires FERC "to facilitate price transparency" in the wholesale markets. FERC is granted authority *but is not required* to prescribe rules it determines necessary to facilitate price transparency, including the establishment of a wholesale electronic information system.

This section preserves the exclusive jurisdiction of the Commodity Futures Trading Commission (CFTC).

Background

Access to accurate and timely wholesale market data has been an issue of debate for at least the past few years. Generally, state regulators do not have ready access to detailed and/or real-time wholesale market data. The state concern has been that since the operation and prices in the wholesale markets have a direct impact on the operations and prices in the retail markets, access to this data is necessary to carry out the states' obligation to ensure just and reasonable retail electric service and rates.

States do not have ready access to detailed, real-time wholesale market data, but the operation and prices in wholesale markets directly affect retail markets.

Federal Action

FERC has no specific rule requirements, but was directed to execute a Memorandum of Understanding (MOU) with the CFTC relating to information sharing within 180 days of the enactment of the section. That MOU was executed on Oct. 12, 2005. The MOU establishes that through written request FERC may obtain futures, options, and other trading information from CFTC. FERC can only disclose the information obtained from the CFTC in a court proceeding where FERC, CFTC, or the United States is a party or in a FERC proceeding involving compliance of a FERC-regulated entity, and where FERC staff is participating, and which will ultimately lead to a FERC order.

PJM adopted a policy for sharing confidential market information with authorized commission personnel.

On Oct. 13, 2005, FERC on behalf of the interagency Electric Energy Market Competition Task Force released a Notice Requesting Comment on Wholesale and Retail Electricity Competition (Docket no. AD05-17-000). The task force was created by Section 1815 of EPAct. It consists of representatives from FERC, Department of Justice, DOE, the Federal Trade Commission, and the Rural Utility Service. While not directly linked to the market transparency provisions, the notice for comment does present several questions that might elicit market monitoring issues from respondents.

NARUC and the states should immediately encourage FERC to determine whether the PJM model provides adequate market transparency.

Implications

The Act says that FERC can obtain information from "any market participant." It is not clear whether government owned or operated utilities automatically fall in that category.

Furthermore, subsection 220(d) exempts entities that have a "*de minimis*" market presence from complying with reporting requirements. Defining "*de minimis*" could be an issue of contention, similar to the past debates about determining market share in the context of the FERC market-based pricing tests. A wholesale generator has zero market presence when it is not running but may have substantial market power during particular load scenarios.

The Act requires FERC to "rely" on existing price publishers and providers of trade processing services "to the maximum extent possible." These publishers and providers usually carry substantial subscription fees and restrictions on redistribution of information. Even if FERC does subscribe to these services, it is not likely that FERC will be able to then make the information publicly available.

The blatant market manipulation and fraudulent trading practices in the West in 2000-2001 drove a demand for more explicit laws and rules on market practices.

In 2004, PJM in collaboration with its members and some PJM states adopted a policy for sharing confidential market information with authorized state commission personnel. Some states expressed concern that this policy still did not sufficiently address their need for access to detailed, real-time market data.

State Action

None required.

Issues for States to Address

To the degree that the states have concerns with existing levels of wholesale market transparency and state regulators' access to market data, NARUC and the states should immediately begin to collaborate with and encourage FERC to determine whether the PJM confidential information sharing model and existing subscription-based market data provide adequate market transparency to "state commissions, buyers, and sellers of wholesale electric energy, users of transmission services, and the public," as was the intention of Congress.

States intending to respond to the task force questions in the electricity competition study docket should specifically address issues of access to timely and non-aggregated data necessary to measure competition and/or make market adjustments to improve competition.

Deadlines

Responses to the joint task force questions on wholesale and retail competition – Nov. 18, 2005

FALSE STATEMENTS AND MARKET MANIPULATION

Statutory Provisions

Sections 1282 and 1283 amend the FPA expressly to:

- Prohibit any entity knowingly and with intent of fraud from reporting any false information relating to wholesale electric prices or transmission availability to a federal agency (new FPA Section 221)
- Make it illegal to use "any manipulative or deceptive device or contrivance" in connection with the purchase or sale of electricity or transmission services subject to FERC jurisdiction in contravention of such rules and regulations as

FERC "may prescribe as necessary appropriate in the public interest or for the protection of electric ratepayers," (new FPA Section 222).

Background

The blatant market manipulations and fraudulent trading practices in the western U.S. energy markets in 2000-2001 drove a demand for more explicit laws and rules regarding market practices.

Federal Action

No specific actions are required, but FERC has already released the following policy statement and two proposed rulemaking notices:

- A policy statement on enforcement (Docket No. PL06-1-000)
- A NOPR on prohibition of energy market manipulation (Docket No, RM06-3-000)
- A NOPR on extending the FERC financial audit challenge procedures to also include challenging operational audits (Docket No. RM06-2-000)

Implications

While these explicit prohibitions may make prosecution of violations easier, the fraudulent activities were already almost certainly illegal under other more general federal laws.

What might be of interest to the states in this section is the language of new FPA Section 222 that seems to express FERC's authority to pass consumer protection rules. Assuming that the term "electric ratepayers" can mean *retail* ratepayers, there may be some concern with how FERC may or may not view the creation of rules in the interest of protecting ratepayers.

State Action

None required.

Issues for States to Address

It is suggested that states pay special attention to any activity FERC undertakes with regard to establishing consumer protection rules or regulations in its jurisdictional wholesale and transmission service markets.

Since EPAct amendments to the FPA apply to "electric ratepayers" states should pay special attention to FERC action establishing consumer protection rules. "Electric ratepayers" does not rule out retail ratepayers.

Deadlines

None

ECONOMIC DISPATCH

Statutory Provisions

Section 1298 directs FERC to convene regional state-FERC joint boards (pursuant to the requirements of FPA Section 209) to study the issues of security constrained economic dispatch within the various regions.

The sole authority of each board is to make recommendations to the FERC regarding issues relevant to what constitutes "security constrained economic dispatch" and how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the joint board region.

FERC has established four regional joint boards to study security-constrained economic dispatch.

Background

When a transmission constraint is caused by a pending/potential overload resulting from a contingent event elsewhere on the network, it is referred to as a "security constraint." Generally speaking, the operation of transmission systems factors in contingencies such as unplanned loss of

Some of the regions covered by the jont boards contain significantly different market areas, which may make consensus recommendations to FERC more difficult.

If a joint board cannot reach consensus, the weight of states' voices could be diminished.

a line, transformer, or generator. This is known as a "security constrained system."

For purposes of the joint boards' proceedings, in its Sept. 30, 2005, order, FERC adopted the definition of economic dispatch provided in Section 1234(b) of EPAct as the definition of security constrained economic dispatch, *i.e.*, "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."

Federal Action

On Sept. 30, 2005, FERC issued an order establishing four regional joint boards, designating a FERC Commissioner to chair each board, and seeking a representative nomination from that each state. The four regions are:

- The South (Texas and states in the southeast and Southwest Power Pool)
- The West (states in the Western Interconnection)
- The Northeast (New York and the states in New England)
- PJM/MISO (states that are served primarily by PJM and MISO)

The memberships of each joint board were announced Oct. 21, 2005.

Implications

Like the economic dispatch study (Section 1234), this section of the Act will raise the question of whether and how best to advance organized markets. Originally, FERC was considering only three joint boards. NARUC then asked FERC to establish six joint boards to better separate the boards by regional differences (NYISO and ISO-NE region, PJM region, MISO region, South and SPP region, Texas region, and West region).

While four boards are better than three, some of the boards contain significantly different market areas which may make consensus recommendations to FERC more difficult. For example, the concept of economic dispatch is likely to be quite different between a state with a traditionally integrated retail market and significant in-state capacity reserves and a state (in the same joint board region) that has a restructured retail market and relies on a significant amount of imported power. In its Sept. 30, 2005, order, FERC acknowledges that there are significant differences among the regions and directs the joint boards to account for these differences.

State Action

Joint board participation.

Issues for States to Address

Managing the differences within a joint board region may be more difficult than managing the differences between existing market (or RTO) regions. One concern might be that if a joint board cannot reach a consensus, or make recommendations based on unanimity or at least majority agreement, the weight of the states' voices will be diminished as federal decisions are made regarding economic dispatch and organized markets.

To the degree that significantly different market conditions exist in the joint board regions (especially the PJM/MISO and South joint board regions), earlier discussion of the issues and understanding of agreements and disagreements between the states in the region is important.

Deadlines

- First meeting of each joint board – November 2005
- Final joint board reports and recommendations due to FERC – May 2, 2006
- FERC report to Congress – Aug. 7, 2006

SITING OF LIQUEFIED NATURAL GAS TERMINALS

Statutory Provisions

Section 311 of the Act gives FERC the exclusive authority to approve a permit for a liquefied natural gas (LNG) terminal. The Act:

- Requires FERC to consult with state/ local representatives on safety and environmental issues
- Constrains the state and local representatives to complete their review of an applicant's request within a specified time period

Background

Probably the most controversial natural gas provision in the Act, at least from the perspective of the coastal states, relates to the siting of liquefied natural gas (LNG) terminals. As in other sections of the Act, the LNG siting provision is a response to a perceived "Nimby" (not-in-my-backyard) syndrome that allegedly has blocked or delayed the development of new energy facilities that may be in the national interest. Overall, the new FERC certification process is depicted by its proponents as both comprehensive and streamlined. Most analyses have shown that LNG will be a critical source of natural gas in the U.S. market. Specifically, studies have projected that natural gas prices in the United States over the next 20 years will be significantly influenced by the amount of LNG imports, with LNG being an especially critical source of new gas supply in the mid and long term.

Federal Action

FERC's authority is conditioned on the applicant meeting statutory requirements for various aspects of the proposed terminal or terminal expansion. Of initial concern to FERC was the promulgation of regulations on the National Environmental Policy Act of 1969 (NEPA) pre-filing process for LNG terminals. Barely meeting the EPAct Section 311(d) established deadline for such rules, FERC issued a final rule regarding pre-filing procedures for review of LNG terminals and other natural gas facilities on Oct. 7, 2005.

EPAct also requires DOE to hold at least three forums within the next year on LNG in states where LNG terminals are under construction. The Act requires the Department to consult and cooperate with different federal agencies in addition to the governors of the states within which LNG terminals are being proposed. The major intent of the forums is "to foster dialogue among federal, state, and local officials, the general public, independent experts, and industry representatives." This dialogue is intended to "identify and develop best practices for addressing the issues and challenges associated with [LNG], building on existing cooperative efforts."

Implications

The intent of Section 311 is to accelerate the development of LNG terminals, which, according to most accounts, will help moderate the future price of natural

Probably the most controversial natural gas provision in the Act relates to the siting of liquefied natural gas. The intent is to accelerate the development of LNG terminals.

States will have important input into FERC's siting process.

Three federal forums will offer an opportunity for state input.

Coastal states will have to decide the level of resources they want to dedicate to siting of LNG terminals. Given the level of controversy, it is likely they will devote considerable effort.

gas. To what extent the Act will shorten the time for LNG-terminal certification falls outside the realm of quantification. The Act will allow states to continue having important input into FERC's siting process. For example, as clarified by the Act, states will retain their right to refuse a permit to an LNG applicant pursuant to the Coastal Zone Management Act, the Clean Water Act or the Clean Air Act; states in effect can veto an LNG terminal that does not satisfy these statutory requirements, although the Act in other ways has made it more difficult for a state or local government to block the siting of an LNG terminal. This is illustrated by the Act's requirement that these representatives must complete their review of an applicant's request within the time period set by FERC. In failing to comply, the applicant for a facility (such as an LNG terminal), under Section 7 of the Natural Gas Act, can file an appeal with the U.S. Court of Appeals for the District of Columbia.

State Action

State commissions should consult two excellent reports on LNG.

No required state action is articulated in the Act. Coastal states in which an application is being sought for a new or expanded LNG terminal will, however, want to be actively involved at FERC.

Issues for States to Address

Participation in Certification and Forums

EPAct explicitly allows for state involvement in a critical way in the decision-making process for LNG siting. A major concern of states and local entities centers on how much weight FERC will assign to their input into the certification process.

The three DOE forums offer another opportunity for state input. Again, an appropriate response of the states would be to coordinate the activities of different agencies and other state entities to maximize their effectiveness.

States will have to decide the level of resources they want to dedicate to input into both FERC's certification process for LNG terminals and DOE-led forums on LNG. It is likely that they will devote considerable effort given the high degree of controversy over LNG-terminal sitings that has occurred so far. As discussed above, states will need to develop a strategy that will maximize their effectiveness before the federal government. One idea is for the state commissions to meet with their governors' offices and other state entities to decide on their approach for intervening at FERC and providing information for DOE forums.

At the 2005 Summer NARUC meetings, the DOE/NARUC LNG Partnership released two timely reports on LNG prepared by ICF Consulting. The first report, a white paper, provides an overview of the economics of LNG in addition to siting, safety, and environmental issues. The report also describes the role of LNG in the current and future U.S. natural gas market and presents guidelines for PUCs in considering LNG siting/expansion in their states. The second report emphasizes the importance of effective (1) stakeholder involvement in LNG siting/expansion proposals and (2) communications strategies. It also discusses the lessons learned from recent LNG siting/expansion proposals in various states. These two reports can greatly assist states in understanding the issues associated with LNG siting in addition to developing a strategy for FERC intervention. It is highly recommended that states where the siting of LNG terminals is an issue review these two reports.

Safety

The Act requires the governor of a state where an LNG terminal is being proposed to designate a state agency to consult with FERC on safety issues. State commissions may therefore want to educate their governors about the exact role states will have on LNG siting, including the selection of the state agency.

FERC must also "review and respond specifically" to the safety issues raised by a state agency in an advisory report or some other medium. State entities will need to work together and coordinate their activities to maximize their effectiveness in presenting their case before FERC.

States, along with the U.S. Coast Guard and local agencies, will also provide advice on the development of an emergency response plan, which the Act requires for construction approval. Individual state entities may want to coordinate their activities, as well as to select a lead agency or other entity, in providing this consultation to FERC.

States will have the option (which they previously did not) of conducting safety inspections upon written notice to FERC, pursuant to federal regulations and guidelines, of an operating LNG terminal. States will not, however, have the authority to impose sanctions for alleged safety violations. These violations will be reported to the Office of Pipeline Safety for further review and determination of action. States with LNG terminals will have to decide whether they want to assume the responsibility of carrying out safety inspections.

Deadlines

FERC promulgation of regulations, on the NEPA pre-filing process for LNG terminals – Oct. 8, 2005

NATIVE LOAD SERVICE OBLIGATION

Statutory Provisions

Section 1233:

- Entitles load-serving entities (distribution utilities or other electric utilities with a service obligation) to use firm transmission rights to deliver energy to meet native load service obligations
- Requires FERC to issue rules on long-term firm transmission rights in organized markets
- Requires implementation of the native load provision in certain markets
- Exempts ERCOT and FERC-authorized existing or future transmission allocations, auctions, or methods employed by a transmission organization on or before Jan. 1, 2005

The Act entitles load serving entities to use firm transmission rights to deliver energy to meet native load service obligations.

Background

Since the supply of electricity on the transmission grid must be constantly adjusted in real time to meet a constantly fluctuating demand, it is difficult for market participants to anticipate how much other activity will be on the grid. Congestion of the grid is a frequent occurrence. Wholesale buyers pay significant congestion costs when they cannot obtain power from the lowest-cost generator. Firm transmission rights guarantee the holder uninterruptible access to transmission on a set schedule, often with a fixed price.

Native load refers to the electric power demands of the retail customers that an electric utility is obligated to serve under statute, regulatory requirement, or contract. This section entitles utilities with a service obligation to use firm transmission rights (or equivalent tradable

Commissioner Jimmy Ervin of North Carolina notes that the provision "does circumscribe FERC's ability to treat the native load priority as unduly discriminatory.

The incentive-based rates established by EPAct are troubling to states since all incentives would be flowed through to load-serving entities and ratepayers without state review.

or financial transmission rights) in order to deliver output or purchased energy to meet their native load service obligations. If a utility transfers the service obligation to another load-serving entity, the successor is entitled to the use of firm transition rights or equivalent tradable rights. The ERCOT area is exempted.

Federal Action

Not later than Aug. 7, 2006, FERC is to issue an order or rule on long-term transmission rights in any organized market to facilitate the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy their service obligation.

In a Notice of Inquiry (NOI) Sept. 16, 2005, FERC asked whether the native load preference established in FERC Order 888 is the same as that required by Section 1233 of the Act.

Implications

Nothing in this section authorizes FERC to take any action not otherwise within FERC's jurisdiction. FERC's proposed standard market design (SMD), which many states opposed, would have undermined the idea of native load. FERC terminated its SMD proceedings in July 2005.

State Action

None required.

Issues for States to Address

NARUC generally supports guaranteeing firm transmission rights for native load service obligations as a way for utilities to fulfill their regulated requirements to provide reliable service to customers at reasonable rates. The native load protection provision of EPAct 2005 poses issues for states, particularly those with traditional regulation. As stated by Commissioner Jimmy Ervin, Chair of NARUC's Electricity Committee, "While it is true that the native load provision does not expand FERC's authority to take any otherwise impermissible action, it does circumscribe FERC's ability to treat the native load priority as unduly discriminatory." State commissions might use the opportunity of the FERC NOI on long-term firm transmission rights, in organized markets to clarify that providing native load priority on existing transmission facilities to a load serving entity is not unduly discriminatory.

Deadlines

FERC rule or order to facilitate utilities' securing firm transmission rights – Aug. 7, 2006

INCENTIVE-BASED TRANSMISSION RATES

Statutory Provisions

Section 1241 amends the FPA to establish incentive-based (including performance-based) rate treatments for interstate transmission.

Background

An open transmission system is necessary for functional electricity markets, but, as noted above, investment in new transmission has lagged behind the amount of new generation being sent across transmission grids. Substantial costs are incurred by the increasing congestion. The intent behind the requirement for incentive-based rate treatments is to increase the level of investment in new transmission capacity and thereby increase reliability and reduce the cost of delivered power by mitigating transmission congestion.

Federal Action

FERC is required to establish the incentive-based rates.

Implications

The rule can provide a higher return on equity to attract new investment. It can also provide for automatic recovery of all prudently incurred costs necessary to comply with mandatory reliability standards and all prudently incurred costs related to transmission infrastructure development.

State Action

None required.

Issues for States to Address

The incentive-based rates are very troublesome for states as all incentives would be flowed through to load-serving entities and retail ratepayers without state regulatory review. The filed rate doctrine would allow utilities to flow through any charges that FERC determines are prudently incurred. But FERC does not have a record of conducting prudence reviews of utility investment expenditures. This is new territory for FERC. State commissions should also be concerned because incentive rates, on their face, might apply to bundled as well as unbundled transmission service.

It is not an absolute guarantee that incentive-based rates will lead to significant amounts of new transmission, or that investments will be aimed at the most needy congestion points. Congestion rents not only drive prices up for buyers, but for sellers as well. Furthermore, congestion whether real or inappropriately manufactured can be an unwanted obstacle or a comforting shield depending on a market participant's place in and view of the market. Other pricing signals and incentives which were intended to encourage wholesale energy market investments have had less than hoped for results. The issue of concern is to be sure that these incentives do not simply become new cost and revenue streams without contributing to the desired purpose. A worst case scenario might be the approval of multiple incentive-based rates and allowed recoveries for transmission additions that appear upon filing to have a prudent intent to reduce congestion in a particular market and thereby ease costs, but upon operation fail to meet that goal through what could appear to be unforeseeable conditions. Thus, costs would be ultimately passed onto the ratepayers without any benefits.

Deadlines

FERC rules for incentive-based rates for transmission by public utilities – Aug. 8, 2006

PARTICIPANT FUNDING FOR TRANSMISSION UPGRADES

Statutory Provisions

Section 1242 permits, but does not require, FERC to approve a participant funding plan that allocates cost related to transmission upgrades or new generator interconnection without regard to whether an applicant is a member of a regional transmission organization.

Transmission congestion can be an unwanted obstacle or a comforting shield depending on a market participant's position and view.

A worst case scenario might be the approval of multiple incentive-based rates that appear prudent but fail to reduce congestion and result in costs passed on to ratepayers.

Participant funding is intended to avoid having native load customers pay for transmission upgrades from which they do not benefit.

The Sense of Congress is that FERC should carefully consider objections of New England states to the proposed LICAP mechanism.

Background

Participant funding is intended to avoid having native load customers pay for transmission upgrades that do not benefit them. Participant funding allocates the costs for new transmission projects among those who are deemed to benefit from the new transmission infrastructure.

Federal Action

None required. FERC is permitted, but not required, to approve participant funding plans, including the cost allocation approach that should be used, without regard to whether the applicant is a member or a FERC-approved RTO.

Implications

FERC might still refuse to allow participant funding if the cost allocation plan results in rates that are unduly discriminatory or preferential. FERC might use such grounds to encourage RTO membership. Alternatively, FERC might allow participant funding for Independent Transmission System Administrators, such as through the Independent Coordinator of Transmission proposed by Entergy.

The overall thrust of EPAct is towards national and regional governance of bulk power grids and wholesale trading markets.

State Action

None required.

Issues for States to Address

Some states have been generally supportive of participant funding; others have been staunchly in favor of socialized funding. Some states favoring participant funding may find objectionable FERC's use of participant funding to encourage RTO membership. State commissions that desire participant funding might consider whether other alternatives, such as independent transmission system administrators, would be acceptable to FERC.

Deadlines

None

LOCATIONAL INSTALLED CAPACITY MECHANISM

In Section 1236, EPAct states the Sense of the Congress regarding the locational installed capacity mechanism in New England. It finds that the governors of the states have objected to the proposed mechanism, arguing that LICAP will not provide adequate assurance that necessary electric generation capacity or reliability will be provided, would impose a high cost on consumers, and would have a significant negative economic impact. The Sense of the Congress is that FERC should carefully consider the states' objections in the proceeding currently before it involving the New England Independent System Operator (ISO-NE).

Capacity markets allow for the buying (typically, by retail load serving entities) and selling of capacity credits, typically by generators (see NRRI primer on capacity markets). The markets are intended to create incentives for new generation capacity to keep pace with new demand. ISO-NE proposed the use of a variation of capacity markets (LICAP) that specifically incorporates transmission congestion into the calculations of needed capacity levels. Opponents say that this LICAP system simply amounts to a subsidy paid to generators that has no real effect on improving the reserve capacity and reliability of the electric markets. This section of the Act puts FERC on notice to pay close attention to concerns raised in New England. The Act does not provide any direct guidance affecting states outside of ISO-NE that employ capacity markets and may include or be considering the inclusion of LICAP type variations, but the issues and concerns raised in New England are not entirely isolated to the ISO-NE market.

SUMMARY

National and Regional Infrastructure Investment

The overall thrust of EPAct 2005 is towards national and regional governance of the operation of the bulk power grids and wholesale trading markets. Prior NRRI research reports on regional regulation and jurisdictional disputes on transmission are helpful for understanding some of the issues raised for states.

Reliability

Improved reliability is a major goal of the sections of the Act that are of interest to state regulators. EPAct calls for more certain and enforceable standards executed at the federal level. The new federal enforcement authority increases utility incentives to comply, as well as providing for penalties for noncompliance.

Transmission Siting

EPAct expedites transmission siting with an aim to improve reliability and open up bottlenecks that limit the ability to meet the demand of growing areas of the country. Under the Act, the federal government can step in when a state does not approve transmission siting in a designated congested corridor in a timely fashion. This represents an erosion of state authority to some degree, but with an overriding national interest in mind. States might find themselves more able to consider national concerns in their own proceedings with a federal backstop behind them. Nonetheless, proceedings, whether state, regional, or at FERC, will be no less controversial than before since they challenge existing land use and rights of way, and some benefits of new transmission lines will likely often apply disproportionately to affected states.

One area where states can chalk up a victory is firm transmission rights.

LNG Terminal Siting

The Act assumes that with continued jurisdictional fragmentation LNG terminals either will not be built or will meet with extended delays. Though the Act gives FERC exclusive authority for permitting LNG terminals, states do have some residual authority and influence. Under the Act, FERC must consult with state and local representatives on safety and environmental issues.

National and International Markets

Repeal of the PUHCA of 1935

The Act repeals PUHCA of 1935 to promote vital national energy and business interests in the United States and across the globe. Removal of the PUHCA of 1935 barrier has even in the few months since passage of the Act resulted in new utility diversification. At the same time, without PUHCA it becomes more difficult to pin down and penalize corporate behavior that has often in the past included inappropriate cross-subsidies and other abuses that harm the rate-paying public.

By strengthening federal oversight of wholesale electricity markets, EPAct shifts regulatory influence to the national level.

Market Transparency

EPAct authorizes FERC to prescribe rules to facilitate price transparency, including using a wholesale electronic information section. It explicitly prohibits utilities from making false statements and manipulating the market.

Native Load Obligation

One area where states can chalk up a victory for their ability to protect jurisdictional customers is in the section on firm transmission rights. The Act guarantees firm transmission rights for native load service obligations, which NARUC has supported as a way for utilities to fulfill their regulated requirements to provide reliable service to customers at reasonable rates. Some states, particularly in regions with traditional regulation and that have opposed prior federal efforts at "standard market design," will be especially pleased that, although the native load provision does not expand FERC's authority to take any otherwise impermissible action, it does appear to circumscribe FERC's ability to treat the native load priority as unduly discriminatory.

Regionalism is a pervasive theme of EPAct.

Retail Customers

Cost Recovery

FERC Commissioner Joseph Kelliher, speaking at the NARUC/NRRI Commissioners Only Summit early in 2005, reminded state regulators that tensions have always existed between the states and the federal government and that the overall balance of responsibilities shifts back and forth over time. Regulation of wholesale electricity is the FERC's responsibility; retail, the states'. Nonetheless, what happens in the wholesale market intimately affects retail customers. By strengthening federal oversight in the wholesale arena, EPAct shifts regulatory influence to the national level and challenges states to continue to carefully review costs that utilities wish to pass on to their customers. New transmission projects, new incentives to meet reliability standards, and new environmental requirements may all increase requests for cost recovery.

Direct administrative costs imposed on the states are relatively low; where states have a choice of level of involvement, they may wish to commit considerable resources.

State Representation and Collaboration

One of the pervasive themes in EPAct 2005 as it affects the states is towards regional bodies or federal or regional consultation of one sort or another. States are likely to want to participate as much as they can in many or all of the consultative and collaborative groups established by the Act so they can adequately represent the interests of their consumers, jurisdictional utilities, and other stakeholders. The national and regional imperatives of the Act also present states with opportunities to enhance their clout through regional collaboration that is not called for directly. EPAct's regional and federal-state deliberations include:

- Consultation with the DOE on its study of corridors of transmission congestion
- Participation in regional bodies advising on electric reliability issues, such as applicability of standards
- Participate in state/FERC joint boards to study security-constrained economic dispatch
- Consultation by a designated state agency with FERC on safety issues of siting LNG terminals
- Consultation with the U.S. Coast Guard and local agencies on response plans for emergencies involving an LNG terminal

Some states may also wish to explore interstate compacts with their neighbors, or at least voluntary regional authorities to carry out transmission siting responsibilities.

Administrative Burden on States

The direct administrative costs imposed on the states by EPAct are relatively low. They must consider several standards under PURPA and decide whether to require jurisdictional utilities to meet them. These are formal proceedings and can be expected to call on the skills of commission economists, attorneys, accountants, and others. Since there are strict deadlines for consideration and determination of the standards and the number and complexity of other proceedings have been increasing, some states may be hard pressed to meet the workload.

Where states have a choice about their level of involvement in EPAct implementation, they are being forced to weigh their level of available resources against the desire make their state interests heard and have weight at the many federal and regional forums. Depending on the level of commitment, these costs could be considerable.

Environmental and Fuel Use Impacts

LNG Siting

The need for new sources of natural gas supplies drives the Act's provisions on LNG siting. The new LNG siting legislation should not jeopardize the environment as states still can veto a new terminal if certain environmental requirements are not met. Under the Act, FERC has lead authority over implementing NEPA, which will require the filing of environmental impact statements. It is hoped that FERC will heed the input of states and local governments, which may include concerns over the safety and environmental aspects of a proposed LNG facility. So far, it seems FERC wants to work closely with the states in certifying new LNG facilities.

PURPA Standards

The PURPA standards contained in EPAct 2005, if adopted and implemented, might encourage greater efficiency, resource adequacy, demand-side conservation, and environment impact improvement. The net metering standard would encourage on-site distributed generation, including solar voltaic power cells. The interconnection standard would encourage distributed generators to interconnect with the grid to sell excess power. The smart metering standard provides for advanced metering, upon request, with time-based rate schedules, also upon request. This standard would also encourage efficient conservation and/or demand-side management, as well as encourage the development of efficient distributed generation. The fuel diversity standard, among other things, encourages the development of renewable energy sources. The fifth standard, fossil generation efficiency, would encourage development of more efficient fossil fuel generation, a development which could cut the amount of fossil fuel per kilowatt-hour produced.

CONCLUSION

Overall, EPAct 2005 takes steps towards a more national and regional approach to governance of the electric power grid and, similarly, eases restraints on corporate structural borders. The most important sections for the states are in Title XII. There is an interrelationship, a woven web, between many of its various subtitles, with an overall thrust of encouraging future investment in the electric infrastructure, both through supply side and demand-side measures. Because federal regulation is more pervasive at the wholesale level, many of the reforms deal with making the wholesale market more robust. For example, the provisions in Subtitle G dealing with market transparency and manipulation are meant to clean up past and prevent future abuses in the wholesale market

The Act creates a woven web of provisions aimed at encouraging investment in the electric infrastructure.

The wholesale market is expected to become more robust.

Further industry consolidation is encouraged by the Act.

Successful implementation requires close coordination of federal regional, and state regulation.

Transmission regulation is an area where the federal government predominates, but states still have a significant role. In Subtitle A, an Electric Reliability Organization (ERO) is established which will supplant the previous functions of the North American Electric Reliability Council. The ERO is allowed to delegate its authority to regional reliability entities. States can participate in such regional reliability entities by establishing regional advisory bodies, which are appointed by state Governors. The regional reliability bodies also designate national interest transmission corridors under Subtitle B, transmission siting.

In order to address both the concerns of transmission siting regulation and apparent lack of financial incentive to build new transmission lines, EPAct 2005 contains Subtitles B and D. Subtitle B instructs the DOE to designate national interest transmission corridors. Subtitle D allows FERC to provide financial incentives to build transmission lines.

To make investment capital available for new transmission and generation, Subtitle E repeals the PUHCA of 1935 and replaces it with the PUHCA of 2005, which merely provides for state and federal access to books and records. Repeal of the 1935 PUHCA will allow for further consolidation of the industry and will also allow diversification of activities, including into nonutility activities. The merger review reform provisions require FERC to provide expedited review of mergers and eases requirements for merger approval. While industry consolidation can lead to large inflows of capital, both state regulators and the FERC must protect wholesale and retail customers from the utility being used as a cash cow, directly or indirectly, with capital flowing out of the industry instead of in. This is perhaps the most challenging area in the act and the area most fraught with danger.

When woven together, the various subtitles in Title XII form a web to improve and reform both the wholesale and retail electricity markets. Successful implementation of the policy goals, however, can only be assured through close coordination between federal, regional, and state regulation, with a high degree of diligence on the part of federal and state regulators to avoid any potential negative impacts of cross-subsidization, financial abuse, or market power that can flow from PUHCA repeal. States have many opportunities to contribute to new regional organizations and collaborative efforts, as well as to contribute to policy making at the federal level.

The National Regulatory Research Institute
1080 Carmack Road
Columbus, Ohio 43210-1002
Phone: 614-292-9404
Fax: 614-292-7196
www.nrri.ohio-state.edu

This report was prepared by the National Regulatory Research Institute (NRRI) with funding provided by the member commissions of the National Association of Regulatory Utility Commissioners (NARUC). The views and opinions of the authors do not necessarily express or reflect the views, opinions or policies of the NRRI, NARUC, or NARUC member commissions.