JONES DAY

AUGUST 2005

ENERGY POLICY ACT OF 2005: NEW LAW TO PRODUCE SIGNIFICANT CHANGES IN ELECTRIC SECTOR

President Bush signed the Energy Policy Act of 2005—the long-awaited energy bill—on August 8, 2005. Like the similarly named Energy Policy Act of 1992, the law is expected to result in significant changes in the electric sector. The new law ("2005 Act") requires the Federal Energy Regulatory Commission ("FERC"), the U.S. Department of Energy (through the Secretary of Energy) ("DOE"), and other federal or state agencies to issue rules to implement the 2005 Act. As they are proposed and finalized over the next several months, the new regulations likely will answer some questions and raise yet others. FERC has created a new page on its web site for issues related to the 2005 Act (http://www.ferc.gov/legal/maj-ord-reg/fed-sta/ene-pol-act.asp) and provided a list of its required rulemaking ("Implementation Overview") at http://www.ferc.gov/legal/maj-ord-reg/fed-sta/08-08-05-overview.pdf.

Among other things, the 2005 Act amends the Federal Power Act ("FPA") and the Public Utility Regulatory Policies Act of 1978 ("PURPA"). The 2005 Act also repeals the Public Utility Holding Company Act of 1935 ("1935 Act") but transfers to FERC certain oversight and record-keeping provisions affecting holding companies that are currently subject to the 1935 Act.

The principal provisions of the 2005 Act addressing regulation of electric utilities appear in Title XII. Title XIII contains new tax incentives (such as tax credits or accelerated depreciation) for various activities, some of which will also be of interest to electric utilities. The full text of the 2005 Act can be found at http://energy.senate.gov/public/_files/ConferenceReport0.pdf.

EXECUTIVE SUMMARY

The 2005 Act enacts most of the energy provisions that have been discussed in Congress over the past several years. Of particular note are the repeal of the 1935 Act, adoption of mandatory electric reliability rules as a response to the Northeast blackout of 2003, measures designed to improve the interstate transmission grid that were viewed as necessary to enhance the markets for wholesale electricity sales, and general electricity market protection reforms, such as transparency in pricing information and anti-market manipulation provisions. The Energy Policy Act of 1992 provided a solid beginning for the creation of interstate electric wholesale markets. As evidenced most spectacularly by the collapse of Enron, however, the market structure that evolved following that law was flawed. The 2005 Act will provide a stronger regulatory platform to provide the necessary ground rules so that more robust, and fair, markets will develop.

Repeal of the 1935 Act, which becomes effective February 8, 2006, may be the single most noteworthy provision of the legislation. Long sought by the electric industry, repeal was touted as necessary to spur additional investment in the sector. The 1935 Act stood as an impediment, but not an insurmountable barrier, to investment in the electric business by non-U.S. interests, financial investors, and other "energy" concerns. This impediment is gone, but numerous regulatory hurdles remain for the nontraditional investor, as well as for future mergers of existing utility companies.

While FERC merger authority is changed, as noted below, FERC approval is not likely to be the major issue for electric utility M&A in the near future. The most challenging approval for this type of deal has always been the state utility regulatory commissions, and recent developments suggest that state vigilance will become even greater with the repeal of the 1935 Act. Expansion of multistate "transmission only" companies, development of merchant transmission, and investment in transmission by financial players and others constitute the most likely immediate results of repeal of the 1935 Act.

As mentioned, 1935 Act repeal was coupled with revised merger authority for FERC. FERC now has clear statutory jurisdiction over the merger of one utility holding company with another (although FERC has asserted this jurisdiction for many years). The 2005 Act closes a small loophole by giving FERC a new jurisdictional hook to approve an acquisition of "generation only" facilities. A few recent generation asset sales escaped FERC jurisdiction by specifically excluding from the sale any FERC jurisdictional assets such as step-up transformers or energy contracts. The new law provides a *de minimis* exception so that a transaction involving assets of under $10 million will not need FERC approval. Given that the exclusion was only $50,000 under the old law, this may be useful for small transactions.

Reforms to improve the transmission grid constitute the bulk of the electricity provisions of the 2005 Act. Under the mandatory reliability provisions, FERC will approve a new entity—the Electric Reliability Organization, or ERO (likely to be the North American Electric Reliability Council)—that will have the power to develop, with FERC participation, reliability standards. All transmission-providing entities, including those generally exempt from FERC authority such as municipalities, will have to comply with the rules or suffer penalties imposed by the ERO or FERC. For the first time, FERC will have authority to approve the siting of transmission lines and provide eminent domain authority to allow the acquisition of needed rights of way. The authority is a limited, "backstop" power and will be available only in a "national interest electric transmission corridor" as determined by the DOE. The 2005 Act represents a compromise on the "participant funding" debate between independent generators and vertically integrated utilities as to who should bear the cost of transmission upgrades necessitated by new generation development. FERC is authorized to approve a participant funding plan that allocates costs related to transmission upgrades or new generator interconnection, without regard to whether an applicant is a member of a FERC-approved transmission organization.

The new law also reduces the patchwork of supervision over the grid by extending FERC jurisdiction over municipal, cooperative, and federal government utilities by allowing FERC to mandate that these entities offer open-access transmission service over their transmission facilities. In a bow to political concerns from the Southeast and Northwest, however, FERC must honor native load service obligations in its regulation of the transmission grid. Transmission investment is enhanced by requiring FERC to implement incentive rate mechanisms, applicable to all transmission providers within its jurisdiction, including governmental utilities that join a FERC-approved transmission organization, to encourage capital improvements and additions to the grid.

In response to the California energy crisis and the Enron collapse, the 2005 Act has added a number of market protection tools to FERC's enforcement powers. Coupled with a significant increase in its general authority to impose penalties and higher fines, FERC will have more flexibility to shape markets to be efficient and fair. FERC has new authority to ensure accurate reporting of energy transaction prices and punish those who file false information, including the authority to bar them from acting as energy traders or officers or directors of a public utility. There is a new sweeping anti-manipulation provision. It is now unlawful for anyone to employ any manipulative or deceptive device or contrivance in connection with the purchase or sale of electric energy or the purchase or sale of transmission services subject to FERC's jurisdiction. The new provision is modeled on longstanding federal securities-law fraud provisions, but allows only FERC, not individual plaintiffs, to enforce the measure.

The 2005 Act amends PURPA to eliminate prospectively the requirement for a public utility to purchase output of a "qualifying facility" if the QF has access to competitive markets, while preserving the mandatory purchase obligation under existing QF contracts. The revised PURPA also repeals the restriction on utility ownership of QFs and further requires state utility commissions and governmental utilities to consider adoption of new standards regarding net metering, fuel source diversity, fossil fuel generation efficiency, and smart metering. The law now requires utilities to provide an interconnection to the transmission grid to customers owning self-generation.

Finally, the 2005 Act provides a reported $9 billion of the total $11.6 billion of tax subsidies to directly or indirectly benefit electric utilities. Every type of fuel used in electric generation gets some benefit, and other tax provisions will help in industry transformation to more competitive markets.

Some proposals that did not make it into the final bill include opening the Alaska National Wildlife Refuge to exploration and drilling, liability protection for the manufacturers of fuel additive MTBE, a federal mandatory renewable portfolio standard, and granting FERC jurisdiction to approve the acquisition of a gas distribution utility by an electric utility or holding company.

The following is a detailed summary, generally presented in the order in which the sections appear in the 2005 Act.

ELECTRIC RELIABILITY STANDARDS

The 2005 Act requires the creation of an Electric Reliability Organization ("ERO") to oversee and ensure the reliability of the nation's high-voltage bulk power grid (Title XII, Subtitle A). Within 180 days of enactment, FERC must issue new rules establishing the criteria an ERO must meet, and thereafter FERC must approve one ERO to act as the reliability entity for the nation's grid.

Following issuance of the new rule, a person may file an application for certification as an ERO. The applicant must show that it has the ability to develop and enforce reliability standards that provide for an adequate level of reliability of the bulk-power system. The applicant also must show that it has established rules that assure its independence from the users, owners, and operators of the bulk-power system; equitably allocate dues, fees, and other charges among end users for all services provided; establish fair and impartial reliability standards and enforcement penalties; provide for reasonable notice and opportunity for public comment and a balance of interests and openness in developing reliability standards; and provide for obtaining recognition in Canada and Mexico. The North American Electric Reliability Council (NERC) has announced that it is prepared to move quickly to become the ERO envisioned in the bill.

The ERO will develop and file reliability standards with FERC. FERC may approve the standards, by rule or order, if the standards are just and reasonable, not unduly discriminatory or preferential, and in the public interest. The ERO must presume that a proposal from a regional entity organized on an Interconnection-wide basis is just and reasonable for the Interconnection. ("Interconnection" is defined as a geographic area in which the operation of bulk-power system components is synchronized and refers to the Eastern Interconnection, the Western Interconnection, and the Electric Reliability Council of Texas (ERCOT).) FERC is to give "due weight" to the technical expertise of the ERO and that of a regional entity with regard to a reliability standard. However, FERC need not defer to the ERO or the regional entity with regard to standards addressing competition.

Proposed standards will become effective upon FERC approval. If FERC disagrees with the proposal, FERC must remand the proposal to the ERO for further consideration. FERC may, on its own motion or as the result of a complaint, order the ERO to submit a proposed standard to address an issue if FERC determines a new standard is necessary.

The 2005 Act gives FERC jurisdiction to enforce by order the reliability standards against all users, owners, and operators of the bulk-power system, including municipal organizations typically exempt from FERC authority. The 2005 Act defines a reliability standard to include a requirement to provide for the reliable operation of the bulk-power system, including requirements for the operation of existing bulk-power system facilities, including cybersecurity protection and the design of planned additions or modifications to facilities to provide for reliable operation of the bulk-power system. A reliability standard may not include any requirement to enlarge facilities or to construct new transmission or generation capacity.

FERC must by rule create a procedure to address conflicts between a reliability standard and the rules, orders, tariffs, or agreements previously issued or accepted by FERC. A Transmission Organization must continue to follow FERC's existing rules and orders until FERC finds a conflict and directs a change under Section 206 of the FPA. If FERC finds that a reliability standard should be changed, the ERO must file a change. A "Transmission Organization" is a newly defined term meaning a Regional Transmission Organization, Independent System Operator, independent transmission provider, or other transmission organization finally approved by FERC for the operation of transmission facilities.

The ERO will be authorized to impose penalties on any user, owner, or operator of the bulk-power system for violation of a reliability standard. In addition, FERC may impose a penalty on its own motion after notice and an opportunity for a hearing.

To impose a penalty, the ERO, after notice and an opportunity for a hearing, must find that the party violated the standard and must then file the notice and record of the proceeding with FERC. Penalties must bear a reasonable relation to the seriousness of the violation and must take into consideration the violator's efforts to remedy the violation in a timely manner. The penalty will take effect on the 31st day after the notice and record are filed with FERC. The penalized party may challenge the penalty by filing a request for review with FERC within 30 days after the ERO files the notice and record. Filing a challenge does not automatically stay the penalty, but FERC may issue a stay pending its review of the party's appeal. FERC also may review a penalty on its own motion. After notice and an opportunity for a hearing, FERC may either affirm, set aside, reinstate or modify the penalty, or remand the case back to the ERO for further proceedings. FERC must develop expedited review procedures for these proceedings.

The 2005 Act does not authorize the ERO to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for the adequacy or safety of electric facilities or services.

FERC must implement regulations that allow the ERO to delegate to certain regional entities the authority for proposing reliability standards to the ERO. The ERO may delegate such authority to a regional entity if, first, the entity is governed by an independent board, a balanced stakeholder board, or a combination independent and balanced stakeholder board, and second, the delegation promotes efficient operation of the bulk-power system. FERC may modify a delegation. Under this provision, entities such as Regional Transmission Organizations ("RTOs") will be able to address reliability concerns affecting their operations.

FERC may take action against the ERO or a regional entity to ensure compliance with a reliability standard or any order affecting the ERO or a regional entity.

The ERO must file any rules or rule changes with FERC. After notice and an opportunity for hearing, FERC will accept the rule or change if it is just and reasonable, not unduly discriminatory or preferential, and in the public interest. FERC or a party may also propose changes to the ERO's rules.

The 2005 Act requires the ERO to conduct periodic assessments of the reliability and adequacy of the bulk-power system in North America. The 2005 Act contemplates that the ERO will, after the President negotiates agreements with Mexico and Canada, coordinate its reliability efforts with those of entities in those countries.

The 2005 Act specifies that nothing in the reliability provisions is intended to preempt any authority of any state to take action to ensure the safety, adequacy, and reliability of electric service within the state, as long as the action is not inconsistent with any federal reliability standard. Within 90 days of application by the ERO or other affected party, FERC shall, after notice and an opportunity for a hearing, determine whether a state action is inconsistent with a reliability standard, "taking into consideration any recommendation by the ERO." FERC may, after consultation with the ERO and the state, stay the effectiveness of any state action pending FERC's issuance of an order.

FERC is required under the 2005 Act to establish a regional advisory body if asked by at least two-thirds of the states within a region that have more than one-half of their load served within the region. The regional body will be composed of one member from each participating state in the region, appointed by the governor of each state. The body may also include representatives of agencies, states, and provinces outside the U.S. The body may provide advice to the ERO, a regional entity, or FERC regarding the governance of an existing or proposed regional entity within the same region, whether a proposed standard or proposed fees are just and reasonable and not unduly discriminatory and in the public interest, and any other issues requested by FERC. FERC may give deference to the advice of a regional body if the body is organized on an interconnection-wide basis.

TRANSMISSION INFRASTRUCTURE MODERNIZATION

Siting of Interstate Electric Transmission Facilities. Under the 2005 EPA, FERC for the first time will have some jurisdiction over the siting of electric transmission facilities and will have the ability to grant eminent domain power to facilitate construction in specified areas (Title XII, Subtitle B).

The 2005 Act requires the DOE, in consultation with affected states, to perform a study of electric transmission congestion. The DOE must conduct the study and recommend transmission corridors within one year of enactment of the 2005 Act and every three years thereafter in consultation with any appropriate regional entity. After considering alternatives and recommendations from interested parties, the DOE may designate any geographic area experiencing transmission-capacity constraints or congestion that adversely affects consumers as a "national interest electric transmission corridor."

In determining whether to designate an area as a national interest transmission corridor, the DOE must consider the following factors:

(1) Whether the economic vitality and development of the area or the end markets served in the area may be constrained by lack of reasonably priced electricity.
(2) Whether economic growth or the end markets in the area may be jeopardized by the limited sources of energy.
(3) Whether a diversification of supply is warranted.
(4) Whether the nation's energy independence would be served by the designation.
(5) Whether the designation would be in the interest of national energy policy.
(6) Whether the designation would enhance national defense and homeland security.

The 2005 Act authorizes three or more contiguous states to enter into a regional compact for the purpose of establishing a regional transmission-siting agency. Such agencies will have the authority to review, certify, and permit siting of transmission facilities, including facilities in national interest transmission corridors.

For regions not covered by a regional siting agency, the 2005 Act gives FERC "backstop" authority to permit transmission lines. FERC may, after notice and opportunity for a hearing, issue one or more permits for the construction of transmission facilities in a designated corridor. Before it can exercise this authority, FERC must first find that one of the following conditions exists:

(1) A state in which the facilities are to be constructed does not have the authority to approve the siting of facilities or consider the interstate benefits of such facilities.
(2) The applicant for the permit is a "transmitting utility" under the 2005 Act but does not qualify to file an application in the subject state because it does not serve end-use customers in the state.
(3) The state entity with authority to issue a permit withheld approval for more than one year after an applicant submitted an application or the designation of an area as a corridor (whichever is later).

(4) The state agency conditioned its approval in such a manner that the proposed construction will not significantly reduce transmission congestion in interstate commerce or is economically infeasible.

FERC also must find that the proposed facilities will be used for the transmission of electric energy in interstate commerce, that the proposal is consistent with the public interest, that the proposal will significantly reduce congestion in interstate commerce and protect or benefit consumers, is consistent with sound national energy policy and will enhance energy independence, and will maximize, to the extent reasonable and economical, the transmission capabilities of existing towers and structures.

The 2005 Act gives applicants the right to acquire the right of way over private property by exercise of the power of eminent domain in the U.S. district court for the district in which the property is located, or in the appropriate court of the state in which the property is located. Any right of way acquired under the 2005 Act must be used exclusively for the construction or modification of electric transmission facilities and within a reasonable time after the acquisition. Any property obtained by eminent domain under this section cannot be used for any other purpose, and the right of way will terminate if the authorized use terminates. Any right of-way acquired under this provision is deemed to be a "taking," and the property owner must be compensated for the fair market value of the property taken.

The DOE is authorized to act as the lead agency for purposes of coordinating all federal authorizations and reviews of a transmission facility. The DOE must coordinate its efforts with any affected state, tribe, or multistate entity also involved in permitting and environmental reviews of a facility. The DOE, in consultation with other agencies, will establish deadlines and milestones for the necessary reviews of a proposed facility so that the DOE may ensure that all permit decisions and reviews required under federal law shall be completed within one year or as soon as practicable. The DOE must establish an expedited pre-application process to allow applicants to obtain information prior to filing an application that will indicate the likelihood of approval and key issues of concern to the agencies. The DOE must prepare a single environmental review report that will be used in all decisions under federal law. If any agency has denied an application or fails to act by the required deadline established by the DOE, the applicant or any state in which the facility is located may appeal to the President. The President, in consultation with the affected agency, shall review the denial or failure to act. Within 90 days of the initiation of the appeal, the President may either grant the application with any appropriate conditions or deny the application.

Within 18 months of enactment of the 2005 Act, the DOE must issue regulations to implement these provisions. Within one year of enactment, the DOE and the heads of all federal agencies with authority to issue an authorization must enter into a memorandum of understanding to ensure timely and coordinated reviews of applications. In exercising its responsibilities under this provision, the DOE shall consult regularly with FERC, RTOs, and other FERC-approved transmission entities.

The permitting provisions of the 2005 Act do not apply in ERCOT.

Third-Party Finance. The 2005 Act makes it possible for third parties to contribute funds to upgrade transmission facilities owned by the Western Area Power Administration (WAPA) or the Southwestern Power Administration (SWPA) (Title XII, Subtitle B, Section 1222).

Advanced Transmission and Power Technologies. FERC is required by the 2005 Act to encourage the deployment of advanced transmission system technologies, such as high-temperature lines, underground cables, advanced conductor technology, high-capacity ceramic wire, optimized line configuration, and others (Title XII, Subtitle B, Section 1223 and 1224).

The DOE may establish a program to support the deployment of certain advanced power system technologies and to improve and protect certain critical governmental, industrial, and commercial processes. An appropriation of $10 million per year, for six years, is authorized for this purpose.

TRANSMISSION OPERATION IMPROVEMENTS

Open Access by Unregulated Transmission Providers. The 2005 Act authorizes FERC to require unregulated transmitting utilities (*i.e.*, those otherwise excluded from FERC jurisdiction under Section 201(f) of the FPA, such as municipal and cooperative utilities) to provide open-access transmission services over their facilities at rates that are comparable to the rates that the unregulated entity charges itself and on the other terms and conditions that are comparable to those under which the unregulated entity provides transmission service to itself and that are not unduly discriminatory or preferential (Title XII, Subtitle C, Section 1231). An unregulated entity is exempt from this requirement if it sells under four million megawatt-hours of electricity per year, does not own or operate any transmission facilities necessary for the operation of an interconnected system (or portion thereof), or meets other criteria that FERC deems are warranted and in the public interest. However, FERC may terminate an exemption if it finds after hearing that continuation of the exemption would unreasonably impair the continued reliability of the transmission grid.

While FERC is not authorized to directly approve transmission rates of unregulated transmitting utilities, these entities are subject to FPA Section 205 rate change procedures, under which they would have to file rate changes with FERC so that FERC could determine if the unregulated utility's rates to others were comparable with the rates charged to itself.

The 2005 Act makes clear that the open-access requirement does not apply to facilities used in local distribution. Further, FERC may not require an unregulated transmission entity to transfer control or operational control of its facilities to a Transmission Organization such as an RTO or to take action that would violate certain IRS rules regarding federal tax-exempt bond issuances.

Federal Utility Participation in Transmission Organizations. Federal regulatory authorities are authorized to transfer control and use of all or part of the transmission system of a federal utility to a "Transmission Organization" (defined as a Regional Transmission Organization, Independent System Operator, independent transmission provider, or other transmission organization approved by FERC for the operation of transmission facilities) (Title XII, Subtitle C, Section 1232). The agreement under which the federal utility joins a Transmission Organization must include performance standards for operation of the transmission system to ensure recovery of all costs and expenses, be consistent with existing contracts and financing arrangements, and be consistent with the statutory authorities, obligations, and limitations. The agreement must also include provisions for monitoring and oversight of the federal utility by the Transmission Organization's terms and conditions, including a provision for resolution of disputes through arbitration and a provision to allow the federal utility to withdraw from the Transmission Organization.

Native Load Service Obligation. The 2005 Act permits utilities with native load obligations to continue to use their firm transmission rights, or equivalent tradable or financial transmission rights, to deliver the output of purchased energy or other generating facilities to meet native load obligations (Title XII, Subtitle C, Section 1233). To the extent that the service obligation covered by the firm transmission rights is transferred to another load-serving entity, the successor load-serving entity will also be entitled to use the firm transmission rights associated with the transferred obligation to serve native load.

The 2005 Act does not affect any existing or future methodology employed by a Transmission Organization for allocating or auctioning transmission rights if the Transmission Organization was authorized by FERC to allocate or auction financial transmission rights on its system as of January 1, 2005, and FERC determines that any future auction is just and reasonable and not unduly discriminatory or preferential. However, if a Transmission Organization did not allocate financial transmission rights prior to January 1, 2005, then, with respect to any application by the Transmission Organization to change its methodology, FERC is required to exercise its authority in a manner consistent with the 2005 Act and take into account the allocation principles identified above.

FERC is authorized to order load-serving entities to make transmission rights not used to meet a native-load obligation available to other entities in a manner that is just and reasonable and not unduly discriminatory or preferential. FERC may not, however, order a load-serving entity to build transmission or distribution facilities. The 2005 Act does not permit FERC to abrogate any contract or service agreement for firm transmission service or rights in effect as of enactment of the 2005 Act.

The native load provisions do not apply within ERCOT.

Study on the Benefits of Economic Dispatch. The DOE, in coordination with the states, is required to study the procedures currently used by electric utilities to perform economic dispatch (Title XII, Subtitle C, Section 1234). Economic dispatch is defined as the operation of generation facilities to produce energy at the lowest cost to serve consumers reliably, recognizing any operational limits of generation and transmission facilities. The study is to identify possible revisions to economic dispatch procedures to improve the ability of nonutility or merchant generation to offer its output for sale via economic dispatch, as well as the potential benefits to residential, commercial, and industrial customers nationally and in each state if identified improved economic dispatch procedures were implemented. (See also "Economic Dispatch" below on page 14.)

The DOE must complete the first study within 90 days of enactment, and perform a new study each year thereafter. The report, which the DOE must send to Congress and the states, shall include any suggested legislative or regulatory changes.

Protection of Transmission Contracts in the Pacific Northwest. The 2005 Act provides for the protection of certain transmission rights for utilities that serve load in the Pacific Northwest. FERC cannot require an entity that held, as of August 8, 2005, firm transmission rights on transmission facilities located in the Pacific Northwest (most of Oregon, Washington, Idaho, Montana, Wyoming, and Nevada) to convert its firm transmission rights to tradable or financial rights (Title XII, Subtitle C, Section 1235). This provision is designed to ensure that, as the market in the Pacific Northwest evolves, current holders of certain firm transmission rights may retain those firm rights and not be required to convert them to another form of transmission rights.

Sense of Congress Regarding Locational Installed Capacity Mechanism. Responding to controversy about the proposed adoption of a locational installed capacity (LICAP) mechanism in New England, the 2005 Act notes the concerns raised by the New England states and declares that FERC should carefully consider the states' objections (Title XII, Subtitle C, Section 1236). (On August 10, 2005, FERC issued an order delaying final action on the LICAP proposal so it could take oral argument and conduct further proceedings. FERC indicated that the LICAP proposal would not be approved for implementation prior to October 1, 2006.)

TRANSMISSION RATE REFORM

Transmission Infrastructure Investment. Within one year of enactment, FERC is required to issue a rule establishing incentive-based (including performance-based) rate treatment for transmission service by public utilities (Title XII, Subtitle D, Section 1241). The goal of the rule is to benefit consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion. FERC's rule is to promote capital investment in the enlargement, improvement, operation, and maintenance of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership; provide a return on equity that attracts new investment in transmission facilities (including related transmission technologies); encourage deployment of transmission technologies and other measures to increase capacity and efficiency of existing transmission facilities and improve the operation of the facilities; and allow recovery of all prudently incurred investment necessary to comply with mandatory reliability standards and all prudently incurred costs related to transmission infrastructure development.

FERC's rule must provide incentives, to the extent within its jurisdiction, to each transmitting utility or electric utility that joins a Transmission Organization. A "transmitting utility" is any entity that owns or operates facilities for transmission of electric energy in interstate commerce, including entities such as municipalities otherwise exempt under Section 201(f) of the FPA.

Participant Funding for New Interconnections and Transmission Upgrades. The 2005 Act authorizes (but does not mandate) FERC to approve a participant funding plan that allocates costs related to transmission upgrades or new generator interconnection, without regard to whether an applicant is a member of a FERC-approved Transmission Organization, if the plan results in rates that are just and reasonable and not unduly discriminatory, and consistent with Sections 205 and 206 of the FPA (Title XII, Subtitle D, Section 1242).

AMENDMENTS TO PURPA

New Federal Standards. The 2005 Act amends PURPA to add three additional federal standards —involving net metering, fuel source diversity, and fossil fuel generation efficiency—that must be considered by state regulatory commissions and nonregulated electric utilities for adoption. (A "nonregulated electric utility," as defined in PURPA, is any person including a state agency or federal agency that sells electric energy.) (Title XII, Subtitle E, Section 1251). Within two years of enactment of the 2005 Act, each state regulatory commission and each nonregulated electric utility must commence consideration, or set a hearing date for consideration, regarding adoption of the new standards. This consideration must be completed within three years of enactment. If a state commission or nonregulated utility fails to comply with these deadlines, the federal requirements will become effective on the date of enactment of the 2005 Act.

Net Metering. Net metering service means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to local distribution facilities may be used to offset electric energy provided by the electric utility to the consumer during the billing period.

Fuel Source Diversity. Each electric utility will be required to develop a plan to minimize dependence on one fuel source to ensure the utility can rely on a diverse range of fuel sources and technologies, including renewable technologies.

Fossil Fuel Generation Efficiency. Each electric utility must develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation.

Smart Metering. Within 18 months of the enactment of the 2005 Act, state regulatory commissions and nonregulated electric utilities must consider for adoption rules under which, within 18 months of enactment, each such utility will offer each of its customer classes, and provide to individual customers on request, a time-based rate schedule under which the rate charge for electric energy varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level (Title XII, Subtitle E, Section 1252). The time-based rates should enable customers to manage energy use through advanced metering and communications technology. The time-based rates that a utility may offer include time-of-use pricing, critical peak pricing, real-time pricing, and credits for consumers with large loads that enter into load reduction agreements.

In a state that allows third-party marketers to sell electric energy to retail electric consumers, those consumers must be entitled to the use of the same time-based metering and communications devices available to the utility's retail consumers.

The DOE is responsible for promoting demand response initiatives. Within 180 days of enactment, the DOE must submit a report to Congress that quantifies and identifies the national benefits of demand response and makes a recommendation for achieving specific levels of benefits by January 1, 2007. Within one year of enactment, FERC must publish an annual report showing by region an assessment of demand response programs and steps taken to implement demand response initiatives.

Cogeneration and Small Power Production Purchase and Sale Requirements. The 2005 Act changes the obligations that utilities have under PURPA to buy electric energy from, and to sell electric energy to, qualifying cogeneration and small power production facilities ("QFs") (Title XII, Subtitle E, Section 1253).

Effective August 8, 2005, electric utilities are no longer required to enter into a new contract or obligation to purchase electric energy from a QF if such QF has access to one of the following:

(1) Independently administered, auction-based day-ahead and real-time wholesale markets for the sale of electric energy and wholesale markets for long-term sales of capacity and electric energy.
(2) Transmission and interconnection services that are provided by a FERC-approved regional transmission entity and administered by an open-access transmission tariff that affords nondiscriminatory treatment to all customers and access to competitive wholesale markets that provide a meaningful opportunity to sell capacity to buyers other than the utility to which the QF is connected.
(3) Wholesale markets for the sale of capacity and electric energy that are as competitive as those described under the first two conditions.

When the conditions described above allowing termination of QF contracts are met with respect to QF agreements entered into after August 8, 2005, an electric utility may request approval from FERC to be relieved of its purchase obligation on a service territory-wide basis. FERC must issue an order within 90 days of the filing of the application. However, any QF, state agency, or other affected person subsequently may apply to FERC to have the purchase obligation reinstated because the above criteria are no longer met. FERC will have 90 days to rule on such applications.

Also upon enactment of the 2005 Act, an electric utility will no longer be required to buy electric energy from, or sell electric energy to, a new cogeneration facility unless the cogeneration facility can demonstrate to FERC that the thermal energy output is used in a productive and beneficial manner and also that the electrical, chemical, and thermal output of the facility will be used fundamentally for industrial or commercial purposes rather than by an electric utility. Within 180 days of enactment, FERC must issue new rules establishing these standards and also ensuring the continuing progress in the development of efficient electric energy generating technology. Only qualifying cogeneration facilities that seek to obligate a utility to purchase its power will be subject to the new rules.

Effective August 8, 2005, no utility will be required to enter into a new contract or obligation to sell electric energy to a QF if FERC finds that competing retail electric suppliers are willing and able to sell and deliver electric energy to the QF, and the electric utility is not required by state law to sell electric energy in its service territory.

The elimination of QF purchase and sale obligations does not apply to any contract or obligation in effect, or that was pending approval before a state regulatory authority, on August 8, 2005.

The 2005 Act requires FERC to issue new rules as necessary to ensure that an electric utility that purchases electric energy from a qualifying cogeneration or small power production facility in accordance with any legally enforceable obligation recovers all prudently incurred costs associated with the purchase.

The 2005 Act changes the ownership restrictions previously imposed on QFs by eliminating the prohibition on an electric utility owning more than 50 percent of the facility.

Interconnection. The 2005 Act amends PURPA to require electric utilities to make available upon request "interconnection service" to any electric consumer that the electric utility serves (Title XII, Subtitle E, Section 1254). "Interconnection service" means service to an electric consumer under which an on-site generating facility on the consumer's premises must be connected to the local distribution facilities. Within two years of enactment, state regulatory authorities and non-regulated utilities must adopt interconnection standards. The 2005 Act does not apply where a state regulatory agency adopted standards or commenced a proceeding to address standards prior to August 8, 2005.

REPEAL OF PUHCA

The 2005 Act enacts a new law, the Public Utility Holding Company Act of 2005 (the "2005 PUHCA"), that provides, among other things, for the repeal of the 1935 Act, to be effective February 8, 2006 (six months after the legislation was signed into law by the president) (Title XII, Subtitle F).

Currently, there are 29 public utility holding company systems registered, and subject to regulation, under the 1935 Act. Under the 1935 Act, the Securities and Exchange Commission ("SEC") has regulated a broad array of transactions by registered holding companies and their subsidiaries. The 1935 Act has governed, among other things, the acquisition of securities (including securities of public utility companies) and utility assets, the issuance of securities, intercompany financings, and affiliate transactions.

Of particular note is the requirement of the 1935 Act that the operations of the holding-company system be limited to "a single integrated public-utility system, and to such other businesses as are reasonably incidental, or economically necessary or appropriate to the operations of such integrated public-utility system." The requirement of an "integrated public utility system" has limited a holding company system to a single coordinated system confined in its operations to a single area or region. It has also limited the operations of a registered holding company system to energy-related businesses. Thus, registered holding companies have not been able to engage in industrial or commercial enterprises.

Because of its restrictions, the 1935 Act has limited the participants in the public utility industry. An acquiror of a public utility has become subject to the 1935 Act and its restrictions, unless an exemption was available. The requirement that the operations of the holding company and its subsidiaries be limited to energy-related activities has imposed an effective barrier to entry. Companies whose businesses are diversified generally have not been willing to become subject to the limitations of the 1935 Act and the requirement to divest nonconforming operations.

Further, the 1935 Act effectively limited the geographic spread of existing holding companies. Although the interpretation of a "single integrated public-utility system" has been expanded in recent years, it nonetheless has imposed an effective constraint on acquisitions by existing holding company systems. As a result, the public utility industry remains generally fragmented, with utilities being confined to a limited geographic area, as the 1935 Act intended.

The repeal of the 1935 Act will remove these geographic and business restrictions on holding companies. Besides the obvious relief from the requirement to obtain SEC approval for acquisitions of new utility assets and utility mergers as well as routine operational matters, such as financing and intercompany service agreements, the repeal of the 1935 Act removes restrictions on the types of investments—whether utility, energy-related, or otherwise—that can be made by holding companies. Further, the repeal of the 1935 Act removes constraints on companies in other businesses acquiring utilities and/or holding companies.

With the repeal of the 1935 Act, there may be a consolidation of the industry—geographically distant utilities will not be barred by federal law from merging. The need to satisfy state concerns and the Wall Street requirement of achieving a merger that makes good business sense, however, will still constrain utility consolidation. The entry of new players into the industry could be of particular significance. Because of the elimination of the geographical limits of the 1935 Act, expansion of multistate "transmission only" companies will now be easier and development of merchant transmission and investment in transmission by financial players and others may expand. See "Merger Review Reform" below on page 13 regarding revised FERC authority over utility mergers.

The 2005 PUHCA also clarifies and expands the authority of FERC over affiliate transactions. Generally, the 2005 PUHCA provides that each utility holding company and any affiliate thereof must provide to FERC such books and records as FERC determines are relevant to costs incurred by an electric public utility or natural gas company within such holding-company system and necessary or appropriate for the protection of utility customers with respect to FERC jurisdictional rates. Under the 2005 PUHCA, FERC must issue rules not later than 90 days after the effective date of the 2005 Act to exempt from these access requirements any person that is a holding company solely with respect to QFs or "exempt wholesale generators" or "foreign utility companies" (each as defined in the 1935 Act), and FERC shall further exempt a person or transaction from such requirements if FERC finds that the books and records of such person or transaction are not relevant to the jurisdictional rates of an electric public utility or natural gas company. "Natural gas company" in this context means any person engaged in the transportation or sale of natural gas in interstate commerce.

The 2005 PUHCA also grants to state regulatory commissions authority to obtain access to books and records of a holding company and its affiliate companies if the state commission determines such books and records are relevant to costs incurred by the electric or gas distribution utility it regulates and access is necessary for the effective discharge by that state commission of its responsibilities. This provision does not preempt any state law or other law under which the state commission may otherwise have such access.

The 2005 PUHCA further confirms that nothing therein affects the authority of FERC to require that jurisdictional rates are just and reasonable, including the ability to deny or approve the pass-through of costs and the prevention of cross-subsidization. FERC is directed to issue regulations and submit to Congress recommendations on technical and conforming amendments to federal law within four months of enactment of the 2005 Act.

The 2005 PUHCA also authorizes FERC, at the election of a holding company system or an applicable state commission, to review and authorize the allocation of costs for non-power goods or administrative or management services provided by a service company to a public utility company in the same holding company system. Within four months of enactment of the 2005 Act, FERC must issue rules to exempt from these provisions any company in a holding-company system whose public utility operations are confined to a single state and any other transactions that FERC finds are not relevant to FERC jurisdictional rates of a public utility.

The 2005 PUHCA has a savings provision designed to allow currently registered holding companies to continue to operate under existing SEC rules, regulations or orders during the transition period between the date of enactment of the 2005 Act and the effective date of repeal of the 1935 Act, even if such order otherwise expires or terminates. In what appears to be an oversight, the savings provisions are not included in those sections of the 2005 PUHCA that become effective prior to the date of repeal of the 1935 Act. The intent to preserve existing approvals during the transition period will be frustrated if this savings provision is narrowly construed. The savings provision also preserves the favorable tax provisions of Section 1081 of the Internal Revenue Code, allowing deferral of gain or loss in certain cases on disposition of assets ordered by the SEC in order to ensure compliance with the 1935 Act, in the case of any such order entered before the effectiveness of repeal.

MARKET TRANSPARENCY, ENFORCEMENT, AND CONSUMER PROTECTION

Transparency. The 2005 Act requires FERC to facilitate price transparency in transmission and energy markets (Title XII, Subtitle G, Section 1281). FERC may issue rules as necessary and appropriate to facilitate transparency. The 2005 Act gives FERC authority to obtain pricing from any market participant and to rely on other entities as well. FERC must rely on established publishers of price information as much as possible but may establish its own electronic information system if it determines it necessary. FERC may not require entities with a *de minimis* market presence to comply with these new reporting requirements.

The new law generally imposes a three-year statute of limitations on violations. No penalty may be assessed for violations occurring more than three years prior to notice of the proposed penalty unless FERC finds that a seller has engaged in fraudulent market manipulation activities materially affecting a contract.

These market transparency provisions do not apply to transactions in ERCOT.

Within 180 days of enactment of the 2005 Act, FERC must enter into a memorandum of understanding with the Commodities Futures Trading Commission relating to information sharing.

False Statements. No entity (including unregulated entities exempt from the FPA under Section 201(f)) shall willfully and knowingly report to a federal agency any information related to the price of electricity sold at wholesale or the availability of transmission capacity, which the person or any other entity knew to be false at the time of reporting with the intent to fraudulently affect the data being compiled by a federal agency (Title XII, Subtitle G, Section 1282).

Market Manipulation. The 2005 Act makes it unlawful for any entity (including entities exempt from the FPA under Section 201(f)) directly or indirectly to use or employ in connection with the purchase or sale of electric energy or the purchase or sale of transmission services subject to FERC's jurisdiction any manipulative or deceptive device or contrivance (as those terms are used in Section 10(b) of the Securities Exchange Act of 1934) in contravention of such rules and regulations as FERC may prescribe in the public interest or for the protection of electric ratepayers (Title XII, Subtitle G, Section 1283). Penalties for violations are summarized in the following section, "Enforcement."

Section 10(b) of the Securities Exchange Act of 1934 is the basis for anti-fraud suits by the SEC or shareholders against corporations for material misstatements of fact or material omissions in information provided in connection with the purchase or sale of securities. This has been a powerful tool in regulating the integrity of the securities markets, and giving similar power to FERC may have significant effects on energy markets. Unlike the case with securities litigation, where private plaintiffs may bring suit based on material misstatements or omissions, the 2005 Act does not create a private right of action. Thus, only FERC will have the power to enforce the anti-manipulation rules.

Enforcement. The 2005 Act increases the criminal penalties for violations of the FPA from a maximum of $5,000 to a maximum of $1 million and the maximum jail time from two years to five years. The criminal penalties for violations of FERC's rules, orders, regulations, restrictions, conditions, or order are increased from $500 per day of violation to $25,000 per day (Title XII, Subtitle G, Section 1284).

FERC's ability to impose civil penalties is increased from a maximum of $10,000 to a maximum of $1 million. Also, the 2005 Act expands the civil penalty provisions to cover violations of any provision of the FPA, and not just certain sections (*i.e.*, Sections 211 through 214), as was previously the case. Several of the new provisions described in this summary are included as new sections of the FPA and will therefore be subject to these penalty provisions.

Refund Effective Date. The 2005 Act provides that a refund effective date may commence upon the date a complaint or a proceeding is instituted and not 60 days thereafter. Previously, if FERC found that rates were not just and reasonable, it could not order refunds of the unjust rates collected during the first 60 days following the institution of the complaint or proceeding (Title XII, Subtitle G, Section 1285).

Refund Authority. The 2005 Act imposes refund obligations on municipal and other state agencies that are otherwise exempt from the FPA when those entities voluntarily make short-term sales (31 days or fewer, excluding monthly contracts subject to automatic renewal) through an organized market in which the rates are established by a FERC-approved tariff and the sale violates the terms of the tariff (Title XII, Subtitle G, Section 1286). An entity that sells less than eight million megawatt-hours of electricity per year or that is an electric cooperative is exempt from the refund obligation. This provision is the result of the meltdown of the California market in 2000 and 2001 and will ensure that FERC will have jurisdiction over all sellers in an organized market.

Consumer Privacy and Unfair Trade Practices. The 2005 Act authorizes the Federal Trade Commission to issue rules protecting electric consumers from disclosure of personal information in connection with the sale or delivery of electricity (Title XII, Subtitle G, Section 1287).

Authority of Court to Prohibit Individuals From Serving as Officers, Directors, and Energy Traders. The 2005 Act amends the FPA to make clear that a court may prohibit, conditionally or otherwise, any individual who is engaged in or has engaged in providing false information (see "False Statements" above on page 12) from acting as an officer or director of an electric utility or from purchasing or selling electric energy or transmission services that are subject to FERC's jurisdiction (Title XII, Subtitle G, Section 1288).

Merger Review Reform. FERC authority to review mergers, dispositions of facilities, and acquisitions of existing generation facilities is revised and, in certain respects, expanded (Title XII, Subtitle G, Section 1289). The authority of FERC under Section 203(a) of the FPA to review dispositions of facilities by public utilities or acquisitions of securities of another public utility by public utilities is limited to transactions with a value in excess of $10 million (previously only $50,000). FERC authority is expanded, however, to include the review of the purchase, lease or other acquisition of an existing generation facility that has a value in excess of $10 million and is used in connection with interstate wholesale sales and over which FERC has jurisdiction for ratemaking purposes. Under prior law, FERC did not have jurisdiction over a transaction involving only generating facilities, unless the transaction also included jurisdictional facilities such as step-up transformers or contracts for the sale of electricity.

FERC is further granted authority to review any transaction by which a holding company system that includes a transmitting utility or an electric utility purchases or acquires any security with a value in excess of $10 million of, or merges or consolidates with, a transmitting utility, an electric utility, or a holding company system that includes a transmitting utility or an electric utility company with a value in excess of $10 million. This provision, in conjunction with existing Section 204 of the FPA governing securities issuances, may give FERC increased authority over intercompany lending transactions in holding company systems, such as money pool transactions.

The 2005 Act amends the FPA to add that FERC must consider, in addition to whether the transaction is consistent with the public interest, whether the transfer will result in cross-subsidization of a nonutility associate company or the pledge or encumbrance of utility assets for the benefit of any associate company in the holding company system.

FERC must issue a rule to establish procedures it will follow for the expeditious consideration of Section 203 applications. The rule must classify transactions into categories that may easily meet the approval standards and then expedite review of such applications. For other transactions, FERC must act within 180 days of the date of filing. If FERC does not act within 180 days, the application shall be deemed granted unless FERC finds, based on good cause, that further consideration is required to determine whether the proposed transaction meets the public interest and does not result in a cross-subsidization. If FERC finds more time is necessary, it may issue an order tolling the time to act on the application for an additional 180 days, at the end of which FERC must grant or deny the application.

The changes to the merger review procedures become effective six months after the date of enactment. However, the changes will not apply to any application that was filed on or before the date of enactment.

ECONOMIC DISPATCH

FERC must convene joint boards on a regional basis to study security constrained economic dispatch (Title XII, Subtitle J; see also "Study on the Benefits of Economic Dispatch" above on page 8). FERC must request each state to nominate a representative for the appropriate regional joint board and will designate a member of FERC to serve as chair.

The sole authority of each joint board will be to consider 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 region and to make recommendations to FERC regarding such issues.

Within one year of enactment, FERC is to issue a report and submit it to Congress regarding the recommendations of the joint boards.

NUCLEAR PROVISIONS

The 2005 Act contains a number of provisions that benefit the nuclear power industry (Title VI). These include (i) up to $2 billion of federal "risk insurance" for up to six new advanced nuclear plants, covering certain costs incurred from delays in achieving commercial operation, (ii) a measure authorizing federal loan guarantees for up to 80 percent of the cost of "innovative technologies" that reduce air pollutants or greenhouse gas emissions, which would include new advanced nuclear plants, (iii) a production tax credit (1.8 cents per kilowatt-hour for eight years) for the first 6,000 megawatts of certain advanced nuclear plants, (iv) authorization for the DOE to spend $1.25 billion on the development of a next-generation nuclear reactor, (v) another $2.7 billion in authorized spending for other nuclear research and development initiatives, (vi) $100 million in authorized spending to demonstrate hydrogen production at two existing nuclear plants, and (vii) extension of the Price-Anderson Act through 2025 (without a "subrogation" provision that increased potential liabilities for contractors). See "Tax Provisions" below on page 16 for additional nuclear-related tax changes.

COAL-RELATED PROVISIONS

A number of provisions relating to coal, most of which are intended to encourage the development and use of clean coal technologies, are included in the 2005 Act (Title IV). These provisions include (i) authorizing $1.8 billion of funding for clean coal power projects, (ii) federal loan guarantees for new technologies (such as coal gasification) that reduce pollutants or greenhouse gas emissions from electric generation, (iii) three new investment tax credits related to new clean coal facilities certified by the government (capped at 7,500 megawatts), (iv) accelerated (seven-year) depreciation of pollution-control equipment installed at coal-burning power plants after 1975, and (v) easing limitations on coal leases on federal lands. See "Tax Provisions" below on page 16 for additional information on coal-related tax changes.

RENEWABLE ENERGY PROVISIONS

The 2005 Act contains general provisions enhancing the viability of renewable energy use as well as additional provisions on geothermal and hydroelectric energy production (Title II). The new law requires the DOE to publish a detailed inventory describing the available amount and characteristics of renewable energy resources within the United States, sets targets for renewable energy consumption by the federal government, and provides incentives and grants for renewable energy use. The geothermal provisions amend existing leasing and lease procedures for geothermal resource purposes, as well as the royalty system for federal lands, in order to encourage the use of geothermal resources.

The 2005 Act amends Section 4(e) of the FPA, which governs the licensing for construction of dams, conduits, and reservoirs, and gives to the Departments of Agriculture and the Interior the power to condition such licenses as relates to federal reservations. FERC is required to accept such conditions. The new language states that an applicant or other party to a licensing proceeding is entitled to an agency trial-type hearing of not more than 90 days on any disputed issues of material fact with respect to license conditions conducted by the agency proposing such conditions.

Section 18 of the FPA, which governs the authority of the Secretaries of Commerce and the Interior to prescribe the installation of fish passage facilities at a licensed project, is also amended to require an agency trial-type hearing of no more than 90 days on any disputed issue of material fact with respect to such fishways.

A person seeking a hydroelectric license may propose alternative conditions if a condition is proposed by the Secretaries of Agriculture or the Interior under Section 4(e) of the FPA for hydro projects lying within any reservation of the United States. As amended, Section 4(e) requires the Secretary of the relevant department to accept the proposed alternative condition and FERC must include the proposed alternative condition in the license if it is determined, based on substantial evidence, that the alternative condition provides for adequate protection and utilization of the reservation, and will either, as compared to the condition initially identified by the Secretary, cost significantly less to implement or result in improved operation of the project's works for electricity production. The Secretary must submit into the public record a written statement explaining the basis for each condition and the reason for not accepting any alternative conditions, giving equal consideration to the effects of the condition adopted and the alternatives not accepted.

The new law establishes incentive payments for generating devices owned or operated by a non-federal entity that generates hydroelectric energy for sale and that are added to an existing dam or conduit. However, the generating device does not qualify for the incentive payment if it necessitates the construction or enlargement of impoundment or diversion structures other than for repair or reconstruction. The incentive payments for any one facility are limited to no more than $750,000 in one calendar year. An incentive payment program is also established for capital improvements at hydro projects that are directly related to improving the efficiency of such facilities by at least 3 percent. The incentive payment is limited to the lesser of 10 percent of the costs of the capital improvement or $750,000 for the particular project.

See "Tax Provisions" below on page 16 for information on renewable-related tax changes.

TAX PROVISIONS

The tax provisions in the 2005 Act include a grab bag of dozens of miscellaneous tax benefits, some of them affecting only a small number of taxpayers (Title XIII). Some observers could characterize the tax provisions as only providing small benefits to each part of the energy industry. Another view is that Congress was trying to provide small but critical incentives for investments in new capacity for production and transmission.

Electric Transmission and Generation. The largest tax benefit to the electric transmission sector appears to be accelerated tax depreciation deductions for new electrical transmission equipment, which can be written off over 15 years instead of 20. To qualify, property must be used in the transmission of electricity for sale at 69kV or more, and the original use of the property must commence with the taxpayer after April 11, 2005. The estimated cost of this provision to the Treasury is $1.239 billion over 10 years.

The largest tax benefit to the electric generation sector appears to be accelerated (an 84-month) tax amortization of the cost of air pollution control facilities used in connection with an electric generation plant that is primarily coal fired and that was not in operation before January 1, 1976. This provision is estimated to cost $1.147 billion. The generation sector may also benefit from the clean coal tax credits discussed below.

In recognition of the losses incurred by some electric utilities in recent years, tax losses of electric utilities in 2003, 2004, and 2005 may be carried back five years (rather than the usual two) to the extent of the utility's investment in electric transmission property or pollution control equipment, thus generating tax refunds. This may offer some planning opportunities to utilities that expect to have a taxable loss in 2005, although some anti-abuse rules will apply. Other provisions of interest to the electric sector include a one-year extension of the rules permitting a spreading over eight years for gain from disposition of certain transmission assets or entities and the relaxation of tax rules governing electric cooperatives (intended to permit greater participation by cooperatives in deregulated markets).

Natural Gas Transmission and Production. New investments in natural gas distribution lines (like new investments in electric transmission equipment) will be entitled to accelerated depreciation deductions, being written off over 15 years instead of 20. To qualify, the new natural gas distribution lines must be placed in service after April 11, 2005, and before January 1, 2011. The estimated cost of this provision to the Treasury is $1.019 billion over 10 years.

The natural gas industry will also be gratified by congressional intervention in its favor in several ongoing tussles with the IRS. Congress confirmed that natural gas gathering lines are depreciable over a seven-year period (rather than 15 years, as the IRS had unsuccessfully claimed in several appeals court cases). Congress also provided a safe-harbor exception from the tax arbitrage rules for prepaid natural gas purchases by municipal utilities and certain other tax-exempt purchasers, which is expected to encourage such arrangements more than existing IRS regulations and rulings.

Natural gas exploration and development should also benefit from new rules permitting two-year amortization of (domestic) geological and geophysical costs, and from a slightly higher production threshold for qualifying as a small refiner that can claim percentage depletion.

Renewable Energy. The "placed in service" deadline for facilities to qualify for tax credits for electricity produced from certain renewable sources under Code Section 45 was extended by two years, to December 31, 2007. The new deadline applies to wind, closed-loop biomass, open-loop biomass, geothermal, small irrigation power, landfill gas, and trash combustion facilities. The deadline was not extended for solar facilities. This two-year extension was a disappointment, since project development cycles can take two years or more for some renewables projects; the industry had hoped for a three-year extension or more. However, this is the first time Congress has acted to extend the Section 45 tax credit before it expired, thus hopefully avoiding a repeat of the "boom and bust" cycles that have long characterized renewable energy development.

The list of sources qualifying for such credits was expanded again to include incremental hydropower, new units at existing trash combustion facilities, coke and coke gas facilities, and coal owned by Indian tribes. Also, previously the credit had applied to electricity produced over the first five or 10 years of production, depending on the type of energy resource; now the credit applies for the first 10 years in almost all cases (but seven for Indian coal and only four for coke and coke gas facilities).

These various changes to the Section 45 credit are expected to cost the Treasury $2.747 billion over 10 years.

In addition, the new law authorizes the issuance before December 31, 2007, of $800 million of tax-credit bonds (*i.e.*, bonds that give tax credits to their holders instead of interest) to support renewable investment (qualified facilities under Section 45) by municipal power authorities, rural cooperatives, and others. There were also a variety of enhancements to the credits for biodiesel and agri-biodiesel, and an expansion in the definition of "small ethanol producer."

Nuclear. The deduction for contributions to a qualified nuclear decommission fund under Code Section 468A was expanded in several key respects and now extends to unregulated merchant producers, to costs for pre-1984 facilities, and to costs in excess of limits specified in earlier private letter rulings. These changes are estimated to cost the Treasury $1.293 billion over 10 years. In addition, a new production tax credit has been provided for a qualifying advanced nuclear facility (1.8 cents per kilowatt-hour for the first eight years after the plant is placed in service). This credit will be allocated by the Treasury among approved projects for up to 6,000 megawatts of capacity and is subject to various other limitations.

Coal. Three new investment tax credits for clean coal facilities are provided: (1) a 20 percent credit for cost of integrated gasification combined-cycle "IGCC" projects (defined to include only investments in property associated with the gasification of coal, including any coal-handling and gas-separation equipment); (2) a 15 percent credit for costs of other advanced coal-based projects that produce electricity; and (3) a 20 percent credit for costs of qualified gasification projects that convert coal into a synthetic gas. However, these credits are available only if the project is certified by the Secretary of the Treasury in consultation with the DOE, and there are caps on the amounts that can be certified under each category (a combined $1.65 billion). Although the details of the certification process are not yet clear, interested parties may need to be ready to move fast.

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