8.0. CURRENT ELECTRIC INDUSTRY REGULATORY SYSTEM IN SPECIFIC STATES.

The degree to which the traditional approach (summarized in Section 7.0 above) to regulation of the electric industry applies varies from state to state. Most states have retained a more traditional approach with vertically integrated, monopoly companies providing electricity generation, transmission, and distribution (but with an increased role for merchant generators) and state PUCs setting rates using cost-based ratemaking. This approach exists along side the approach taken by the FERC of promoting competition in wholesale electricity sales. However, some states have started, or are well along in the process of, separating (functionally within a company or structurally among separate companies) electricity generation from transmission and distribution, promoting competition in retail electricity generation and sales, and allowing the competitive market to determine retail sale prices for electricity. Whether or not the separation is by function or structure, electricity distribution continues to be provided, and regulated, as a monopoly service.

Below are discussed the electric industry regulatory systems in several sample states. Five states with significant coal reserves and production (Indiana, Kentucky, New Mexico, Ohio, and Texas) were selected as sample states because states with significant coal reserves and production are more likely to be interested in encouraging local construction of new IGCC plants in order to promote economic development.[162] These five states also provide a spectrum of electric industry regulation, ranging from states following a more traditional approach (Indiana, Kentucky, and New Mexico) to states following a competitive approach (Ohio and Texas).[163]

For Indiana, Kentucky, and New Mexico, the existing regulatory system is described, with particular emphasis on: state PUC jurisdiction and designation of service areas; submission and treatment of rate change requests; determination of test period and cost of service; determination of rate base and treatment of cancelled plant and construction work in progress; use of adjustment clauses; and coal- or other fuel-related provisions. New Mexico's now-repealed retail electric competition provisions are also discussed. For Ohio and Texas, the pre-retail-competition regulatory system is described, focusing on the same matters as for the more traditional states. Then the provisions under retail competition are described, with particular focus on: restructuring through separation of retail electricity generation and sales from transmission and distribution; imposition of

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[162] The states with significant coal reserves and production (defined, for purposes of this paper, as states with estimated recoverable reserves of at least 2,500 million short tons and annual production of at least 15,000 thousand short tons) are, grouped by region: Kentucky, Pennsylvania, and West Virginia; Indiana, Ohio, and Illinois; Texas and Alabama; and New Mexico, Colorado, Montana, North Dakota, Utah, and Wyoming. See http://www.eia.doe.gov/cnea/coal/page/acr/table1.html and http://www.eia.doe.gov/cneaf/coal/page/acr/table15.html.

[163] Of the states with significant coal reserves and production, all except the following have retained a more traditional approach to electric industry regulation: Ohio, Texas, Illinois, and Pennsylvania. See http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html.

nonbypassable wires charges; and provider-of-last-resort requirements. In addition to the detailed discussion of the regulatory systems in the five states, certain coal-related regulatory provisions for several other states (i.e., Colorado, Illinois, Minnesota, Pennsylvania, and West Virginia) are cited. It should be noted that often the official name of the state PUC in a state discussed below has changed over time; this paper refers to the state PUCs by their most current, official names.

8.1. States with a more traditional electric industry regulatory system.

8.11. Indiana.

Jurisdiction.

Indiana has largely retained a more traditional approach to electric industry regulation. Indiana statute grants the Indiana Utility Regulatory Commission (IURC) jurisdiction over "public utilities," which is defined to include every corporation, partnership, or company that owns, manages, or controls any plant or equipment within the State for "production, transmission, delivery, or furnishing of heat, light, water, or power." Indiana Code (IC) 8-1-2-1(a)(2). For some (but not all) purposes, the definition of "public utility" excludes municipally owned utilities, and the IURC's jurisdiction over municipally owned utilities is not as broad as its jurisdiction over other public utilities. Compare IC 8-1-2-1(a) (defining "public utility" to exclude municipal utilities in connection with rate regulation) and IC 8-1-8.5-1(a) (defining "public utility" to include municipal utilities in connection with power plant construction). Rural electric cooperatives are not excluded from IURC jurisdiction. Further, the IURC may decline to exercise jurisdiction over an "energy utility" or over "retail energy service" of an "energy utility." IC 8-1-2.5-5(a). The IURC has used this authority to decline jurisdiction over merchant plants. See, e.g., Hammond Energy L.L.C., 2002 WL 32091044 (IURC Nov. 26, 2002) (declining jurisdiction over qualifying facility/merchant plant); see also Citizens Action Coalition of Indiana v. Indiana Statewide Association of Rural Electric Cooperatives, 693 N.E.2d 1324 (Ind. Ct. App.1998) (discussing authority under IC 8-1-2.5-5)

Each "electricity supplier" (i.e., each company that "furnishes retail electric service to the public" (IC 8-1-2.3-2(b)) has an "assigned service area." IC 8-1-2.3-3. The assigned service areas cannot be changed, except under limited circumstances involving, e.g., mutual agreement of affected utilities or certain annexations by a municipality with a municipal utility. IC 8-1-2.3-3(h) and 8-1-2.3-6. So long as adequate service is provided, the electricity supplier has the sole right to furnish retail electric service in its assigned service area. IC 8-1-2.3-4(a). See also IC 8-1-2-86(a) (limiting operation of more than one utility in a municipality); and Indiana Gas Co. v. Office of Utility Consumer Counselor, 575 N.E.2d 1044, 1046 (Ind. Ct. App. 1991) (stating that utility regulation "arises out of a 'bargain' struck between the utilities and the state" under which utilities

are regulated to ensure provision of the best possible service as "a quid pro quo for being granted a monopoly in a geographical area" for the service).

Ratemaking process: rate changes; test period; rate base; and rate of return.

Under Indiana statute, a public utility's rates must be "reasonable and just" (IC 8-1-2-4), and "unnecessary or excessive" costs cannot be considered in setting such rates (IC 8-1-2-48(a)). The rates must be reflected in rate schedules filed with the IURC (IC 8-1-2-38), and no changes may be made to the rate schedules unless the public utility provides 30 days' notice to the IURC (or such shorter notice as the IURC allows) and the IURC approves the changes (IC 8-1-2-42(a)). A public utility cannot file a request for a general rate increase within 15 months of its prior general rate increase request. Id. However, the IURC may order a "more timely increase" if the increase is for a different type of service, if the "utility's financial integrity or service reliability is threatened" (IC 8-1-2-42(a)(2)) or if the increase is based on a "rate structure previously approved" or on orders of federal courts or regulatory agencies (IC 8-1-2-42(a)(3)).

The IURC must generally review public utilities' "basic rates and charges" at least every 4 years. IC 8-1-2-42.5. If the IURC finds that any rates are unjust or unreasonable, the IURC must determine just and reasonable rates to be charged in the future. IC 8-1-2-68.

The IURC has some flexibility in setting rates in that it may approve rates based on "market or average prices, price caps, index based prices," or performance based prices. IC 8-1-2.5-6(a)(2). However, the IURC has followed a more traditional approach of cost-based ratemaking.

In particular, the IURC generally uses the following approach to set rates. The IURC's primary objective in a rate case is to establish rates that are "sufficient to permit the utility to meet its operating expenses plus a return on investment which will compensate its investors." L.S. Ayers & Co. v. Indianapolis Power & Light Co., 351 N.E.2d 814, 819 (Ind. Ct. App. 1976) (citing FPC v. Hope). This usually involves an initial determination of the utility's future revenue requirement based on the operating results of a test year, which is generally the most recent year for which complete data are available.

The IURC may adjust the test year results in order to disallow excessive or imprudent expenditures or to correct for any unrepresentative operating results. Id. at 819-20; see also City of Evansville v. Southern Indiana Gas and Electric Co., 339 N.E.2d 562, 569-71 (Ind. Ct. App. 1975) (stating that IURC has discretion to disallow costs and adjust test period costs to make them representative of normal operation in the test period and of future operation); and Indiana Gas, 675 N.E.2d at 745 (stating that rates can not be based on "hypothetical" expenses). The IURC may also disallow expenditures that are not sufficiently related to the provision of utility service. Indiana Gas, 675 N.E. at 744 (holding that operating costs must have a "connection" to utility service and upholding disallowance of costs of cleanup of hazardous wastes produced before utility ownership of sites because connection of costs to utility service was "too tenuous").

In addition, the IURC must determine the "fair value" of a public utility's property that is "actually used and useful for the convenience of the public." IC 8-1-2-6. Used and useful property is property "actually devoted to" and "reasonabl[y] necessary to" providing utility service. Citizens Action Coalition of Indiana Inc. v. Northern Indiana Public Service Co., 472 N.E.2d 938, 941 (Ind. Ct. App. 1984), aff'd, 485 N.E.2d 610 (Ind. 1985), cert. den., 476 U.S. 1137 (1986). In making the "fair value" determination, the IURC must consider both the original cost and the reproduction cost of the property (e.g., an electricity generating plant) and must balance this evidence along with other relevant factors to reach a figure that is "fair and equitable to both investor and consumer." Capital Improvement Board of Managers of Marion County v. Public Service Commission of Indiana, 375 N.E.2d 616, 631 (Ind. Ct. App. 1978); see also Indianapolis Water Co. v. Public Service Commission of Indiana, 484 N.E.2d 635, 638-40 (Ind. Ct. App. 1985) (holding that IURC cannot ignore "inflation" in determining "fair value" of property). Since utility property must be used and useful to be included in rate base, return on capital during construction accrues as AFUDC and is added to rate base when the plant goes into service. However, the IURC considers on a case-by-case basis the financial consequences of such an approach and may allow AFUDC to continue to accrue until new rates that include the plant costs go into effect. See, e.g., Northern Indiana Public Service Co., 71 PUR4th 462, 464-65 (IURC Nov. 27, 1985).

Except as modified by certain statutory provisions adopted in the 1980s in response to nuclear plant cancellations (and discussed below), the fair value of used and useful utility property is the rate base for which the IURC must set a rate of return, which must meet the requirements in Bluefield Water Works & Improvement. L.S. Ayers, 351 N.E.2d at 821. The company's return on capital is determined by considering the amount and cost of each component (debt, preferred stock, and common stock) of the company's capital structure. City of Evansville, 339 N.E.2d at 569-70. In setting rate of return the IURC may consider various factors including "the ability to attract new capital, a comparison with return in other industries, production efficiency, and credit ratings." Office of Utility Consumer Counselor v. Public Service Co. of Indiana, 449 N.E.2d 604, 609 (Ind. Ct. App. 1983). However, the IURC must set a rate of return based on the "impact of known circumstances," and not on "speculation" concerning, e.g., the impact of possible legislation not yet enacted. Citizens Action Coalition of Indiana v. Public Service Co. of Indiana, 612 N.E.2d 199, 201 (Ind. Ct. App. 1993).

The above-described ratemaking approach was applied to several nuclear plants in Indiana whose construction was commenced but which were cancelled in the 1980s prior to completion. The IURC's reviews of the cancelled plants, like the review of completed plants, were conducted after the fact, i.e., after construction was completed or terminated.

For example, a public utility began construction of a nuclear plant in 1970 but cancelled the project in 1981 due to litigation, opposition to licensing, and escalating costs. Determining that the decision to build the plant was prudent when construction began, the IURC allowed the utility to amortize, and thereby recover in its rates, about $191 million

out of a total of about $206 million invested in the project. No return on the capital was allowed. On review, the Indiana Supreme Court reversed the IURC's decision on the ground that the cancelled plant was not used and useful. Citizens Action Coalition of Indiana, 485 N.E.2d at 614. As the Court explained, the ratepayers cannot be required to "replenish lost capital which had never become 'used and useful' property or, in other words be required to act..., as insurer of the investor's risk, unless the consumers received an interest in return which provided an opportunity to earn a return on the capital supplied." Id. at 615. The Court distinguished between plant that was used and useful and so could be amortized after retirement and plant that never became used and useful and so could not be amortized. Subsequently, the Court clarified that even "planning, analysis, and investigation expenses" associated with the cancelled plant were not recoverable. Northern Indiana Public Service Co. v. Citizens Action Coalition of Indiana, 548 N.E.2d 153, 156 (Ind. 1989). See also National Rural Utilities Cooperative Finance Corp. v. Public Service Commission of Indiana, 528 N.E.2d 95, 103 (Ind. Ct. App. 1988), aff'd, 552 N.E.2d 23 (Ind. 1990) (upholding denial of recovery of costs of cancelled nuclear plant as not "used and useful," even though owner was insolvent).

In light of the Court's 1985 Citizens Action Coalition of Indiana decision, the IURC took a different approach concerning recovery of costs incurred by another public utility for another cancelled nuclear plant. That public utility began construction of a nuclear plant but cancelled the project in light of construction delays, cost escalations, and a task force report recommending cancellation. Consistent with Citizens Action Coalition of Indiana, the IURC did not allow recover of the costs of the cancelled plant. However, in setting the utility's rates, the IURC added a risk premium to the rate of return on the utility's rate base (which did not include the nuclear plant costs). Upon review of the IURC's decision, the Court upheld the approval of a risk premium to reflect the utility's increased risks of lack of access to capital markets, cash flow deficiency, inflated equity cost, and insolvency as a result of the writing off of the utility's investment in the cancelled nuclear plant. Citizens Action Coalition of Indiana Inc. v. Public Service Co. of Indiana, 552 N.E.2d 834, 838 (Ind. Ct. App. 1990).

The IURC took further action concerning recovery of the utility's cancelled plant investment. The IURC allowed the utility to recover, as an amortized "regulatory asset," $475 million of federal income tax savings that would be realized from deducting the utility's net loss due to the plant cancellation from the utility's net income. The Court had previously held that such tax savings should be retained by the utility. Id. at 839-40. Although the federal income tax rate was subsequently reduced, the IURC did not reduce the utility's rates to reflect the lower tax benefit. The Court reversed the IURC on the ground that the failure to reduce rates to reflect the reduced tax benefit had an effect analogous to amortizing the cancelled plant, an approach that had been previously rejected. Citizens Action Coalition of Indiana Inc. v. Public Service Co. of Indiana, 582 N.E.2d 330, 336 (Ind. 1990).

After the decisions denying recovery of costs of cancelled nuclear plants, Indiana adopted statutory provisions to allow for recovery of cancelled plant under certain circumstances. Under these provisions, proposed construction of new facilities by a public utility (including a municipal utility) must be approved upfront by the IURC. In particular, the IURC must develop and keep current an analysis of the long-range needs for expansion of facilities for electricity generation in the state. IC 8-1-8.5-3(a). A public utility must not construct, purchase, or lease any "facility for the generation of electricity" (e.g., a new IGCC plant) for use in furnishing public utility service without first obtaining a certificate of public convenience and necessity from the IURC. IC 8-1-8.5-2. In order to obtain such a certificate, the utility must file an estimate of the construction, purchase, or lease cost of the proposed facility. IC 8-1-8.5-5(a). In approving the certificate, the IURC must make a finding on the best estimate of the facility's costs. In addition, the IURC must make findings that, inter alia, the facility is required by the public convenience and necessity and is consistent with the IURC's analysis of long-range needs and with any approved utility-specific proposal as to future needs for serving the state or the utility's service area. IC 8-1-8.5-5(b)(2).

Moreover, the certificate of public convenience and necessity is subject to future review by the IURC. The certificate must be reviewed if the IURC's estimate of future growth in electricity use changes and must be modified or revoked if completion of the facility is no longer in the public interest. IC 8-1-8.5-5.5. In general, absent fraud, concealment, or gross mismanagement, a utility "shall recover" through its rates the actual costs (including capital investment and return on capital) that the utility incurs in reliance on the certificate of public convenience and necessity for the facility. IC 8-1-8.5-6.5. Cost recovery begins once the facility is completed and used and useful or, to the extent allowed, after the facility is cancelled and construction is terminated.

Further, after issuance of the certificate, as construction of the facility proceeds, the IURC must conduct, if requested by the utility, an ongoing review of the construction and the costs and may modify or revoke the certificate if the construction or costs are disapproved. However, utility has the option of electing to have the IURC instead conduct review of construction and costs only subsequent to completion or cancellation of the facility. IC 8-1-8.5-6. The advantage of ongoing review by the IURC is that construction costs approved in the ongoing review (and return on those costs) must be included in the utility's rates without further IURC review. This includes both cases where the facility is completed (IC 8-1-8.5-6.5(1)) and cases where the facility is cancelled due to modification or revocation of the certificate as a result of a change in the IURC's future electricity demand estimates or of the IURC's disapproval of other construction costs in the ongoing review (IC 8-1-8.5-6.5(3)). Another advantage is that the determination that imposes costs on ratepayers is made earlier (i.e., after each ongoing review proceeding), although the actual pass-through of approved costs does not begin until the facility is completed or cancelled. In contrast, if only subsequent review is conducted by the IURC, then construction costs of completed or cancelled plant (and

return on those costs) within the certificate amount are included in the utility's rates unless they result from "inadequate quality control" and costs in excess of the certificate amount are included in rates only if the construction is shown to be "necessary and prudent." IC 8-1-8.5-6.5(2) and (4). Also the determination imposing costs on ratepayers is not made until the after-the-fact-review is conducted. While utilities have requested, and the IURC has approved, certificates for new electricity generating plant, none of these plants have been cancelled and so the provisions concerning recovery of costs of cancelled plant have not as yet been applied.

Indiana adopted similar statutory provisions concerning approval of, and cost recovery for, capital projects associated with compliance requirements for the Acid Rain Program under the Clean Air Act. A utility has the option of submitting an environmental compliance plan (IC 8-1-27-6), which includes the costs of developing and implementing the plan and is reviewed by the IURC (IC 8-1-27-8). In the absence of "fraud, concealment, gross mismanagement, or inadequate quality control" (IC 8-1-27-12(a)), the utility may include in rate base the costs of completed projects consistent with the approved plan if the projects are "used and useful" (IC 8-1-27-12(c)). To the extent such costs exceed the amount in the approved plan, the costs may be recovered if they are "necessary and prudent." IC 8-1-27-12(b). These criteria for recovery also apply, if the plan is modified by the IURC, to costs under the plan that were incurred before such modification. IC 8-1-26-16. If the utility cancels a project due to the IURC's withdrawal of approval of inclusion in the plan, the utility may recover previously incurred costs and associated return (absent fraud, concealment, gross mismanagement, or inadequate quality control) that were previously approved or, for costs in excess of the previously approved plan, that are necessary and prudent. IC 8-1-27-17. The IURC must conduct an ongoing review, if requested by the utility, of the capital project, and recovery of costs approved in such a review cannot be challenged if the project is "used and useful." IC 8-1-27-19.

Adjustment clauses.

Rates may include a fuel adjustment clause. City of Evansville, 339 N.E.2d at 591-95; see also IC 8-1-2-42(b) (stating that no changes in rates "based on costs" are "effective without the approval" of the IURC) and 8-1-2-42(d) (allowing changes in the fuel charge no more frequently than every three months). The fuel cost charge may be based on the cost of fuel used by the public utility to generate electricity or the cost of fuel included in a utility's purchased power costs. The IURC will approve a requested fuel cost charge if, inter alia: the utility made "every reasonable effort to acquire fuel and generate or purchase power or both" in order to provide electricity "at the lowest fuel cost reasonably possible" (IC 8-1-2-42(d)(1)); increased fuel costs are not offset by other decreased operating costs; and the charge will not result in a return exceeding the utility's allowed return. IC 8-1-2-42(d). The utility must also provide reasonable estimates of future, average fuel costs. Before approving any rate change based on cost of fuel, the IURC

must examine the utility's books and records and hold "a summary hearing on the sole issue of the fuel charge." IC 8-1-2-42(b). The IURC's consumer counselor must review and report to the IURC on any proposed fuel cost charge within 20 days after the request is filed, and the IURC must hold the summary hearing within 20 days after receipt of such report. Id.

Similarly, rates may include other adjustment clauses determined by the IURC to be appropriate. IC 8-1-2-42(a) distinguishes between, and authorizes the IURC to allow, "a general increase in basic rates and charges" (e.g., a rate increase in a general rate case) and "changes in rates related solely to the cost of fuel or to the cost of purchased gas or purchased electricity or adjustments in accordance with tracking provisions approved by" the IURC. In accordance with these provisions, the IURC has approved the inclusion of purchased power demand costs in adjustment clauses because the costs are potentially volatile. See, e.g., PSI Energy, Inc., 210 PUR4th 299, 2001 WL 797974 (IURC May 16, 2001); and PSI Energy Inc. v. Indiana Office of Utility Consumer Counsel, 764 N.E.2d 772 (Ind. Ct. App. 2002), transfer den., 783 N.E.2d 698 (Ind. 2002). The IURC has also allowed inclusion of payments by the owner of the combined cycle portion of an IGCC plant for coal gasification services provided by the owner of the coal gasification portion of the plant because of uncertainty as to the level of payments over time. PSI Energy, Inc., 173 PUR4th 393, 456-58, 1996 WL 767535 (IURC Sept. 27, 1996).

Special provisions for clean coal technology.

Over several years, Indiana has adopted an array of special provisions aimed at encouraging "clean coal technology." The earliest provision, IC 8-1-2-6.6 (initially adopted in 1985), addresses inclusion in rates of certain construction costs associated with "clean coal technology," which is defined as including technology that "directly or indirectly" reduces sulfur or nitrogen based emissions associated with combustion or use of coal and that is "not in general commercial use at the same or greater scale" in the U.S. as of January 1, 1989. IC 8-1-2-6.6(a) (definition of "clean coal technology"). A utility may include in rate base, as construction work in progress or CWIP, the value of air pollution control property where construction began after October 1985 and is ongoing and where the property constitutes clean coal technology approved by the IURC and is designed to "accommodate" burning of Illinois Basin coal. IC 8-1-2-6.6(a) (definition of "qualified pollution control property"). The facility must burn "only Indiana coal as its primary fuel source" (IC 8-1-2-6.6(b)(1)) or show justification for burning "some non-Indiana coal" (IC 8-1-2-6.6(b)(2)).

This provision (along with similar provisions in IC 8-1-27-1, et seq., discussed above) was successfully challenged as contrary to the commerce clause of the U.S. Constitution because of its limitation to controls on facilities designed for and burning Indiana coal. General Motors Corp. v. Indianapolis Power & Light Co., 654 N.E.2d 752, 763-67 (Ind. Ct. App. 1995). A similar provision was adopted (in 1990) that allows rate base treatment of CWIP for air pollution control property whose construction began after March 2002

and is ongoing, but the provision is not limited to facilities designed for and burning Indiana coal. The provision defines, as clean coal technology, technology that reduces mercury (as well as technology that reduces sulfur or nitrogen emissions) and that was not in general commercial use on November 15, 1990. IC 8-1-2-6.8.

Under either IC 8-1-2-6.6 or 8-1-2-6.8, the utility may request rate base treatment to the extent that the qualified air pollution control property has been under construction for at least six months. 170 Indiana Administrative Code (IAC) 4-6-9. The inclusion of a portion of the value of air pollution control property under construction in rate base, for purposes of a general rate case, means that the utility's rates may recover the return on capital associated with that portion of utility's investment in such property. The IURC must approve the use of air pollution control property if, inter alia, the costs are reasonable. Approval is deemed granted if the property is covered by a certification under IC 8-1-8.5-1, et seq. , a certification under analogous provisions (discussed below) in IC 8-1-8.7-1, et seq., or a utility's approved environmental compliance plan under the Clean Air Act under IC 8-1-27-1, et seq. 170 IAC 4-6-4. The IURC must give rate base treatment, during construction, to approved air pollution control property and may do so in a general rate proceeding, in a certification proceeding under IC 8-1-8.5-1, et seq. or IC 8-1-8.7-1, et seq. , or in an environmental-compliance-plan review proceeding under IC 8-1-27-1, et seq. 170 IAC 4-6-11. Rate treatment of air pollution control property when construction is cancelled or indefinitely suspended is governed by the appropriate provisions under IC 8-1-8.5-1, et seq., 8-1-8.7-1, et seq., or 8-1-27-1, et seq.. 170 IAC 4-6-23. After its initial request for rate base treatment of air pollution control property, the utility may request such treatment for additional amounts of such property in six-month intervals. 170 IAC 4-6-18. Assuming that the IURC's handling of such requests takes about four months, this means that a utility may recover, on an ongoing basis, the return on capital for each six-month portion of investment in air pollution control equipment about four to ten months after making that portion of the investment. During the lag period between making the investment and including the return on capital for the investment in the rates, the utility treats the return on capital as allowance for funds during construction (AFUDC). The AFUDC is subsequently treated as part of the value of the investment and is eventually added to rate base, consistent with the appropriate provisions under IC 8-1-8.5-1, et seq., 8-1-8.7-1, et seq., or 8-1-27-1, et seq..

The IURC has applied IC 8-1-6.6 and 8-1-6.8 to projects involving construction of nitrogen oxides emission controls (e.g., selective catalytic reduction control equipment and combustion modifications such as low NOx burners) undertaken by some utilities. See, e.g., PSI Energy, Inc., 2001 WL 401306 at 6 (IURC Feb. 14, 2001). Moreover, in several cases, the IURC held that it has the authority to allow a utility to recover -- through an adjustment clause, rather than in a rate case -- the return on capital for CWIP in such projects during ongoing emission control installation. The IURC stated that it was adopting this approach because: the investment in the projects was substantial; it would be difficult to coordinate initiation of rate cases with investments in ongoing

construction; and the inability to recover return on capital on an ongoing basis would have a significant, adverse impact on the companies involved. See, e.g., Northern Indiana Public Service Co., 2002 WL 32089927 at 9 (IURC Nov. 26, 2002), aff'd, Citizens Action Coalition v. Northern Indiana Public Service Co., 804 N.E.2d 289 (Ind. Ct. App. 2004); and Indianapolis Power & Light Co., 2002 WL 32091040 at 8 (IURC Nov. 14, 2002).

Although the operative terms in IC 8-1-6.6 and 8-1-6.8, "air pollution control property" and "clean coal technology," have been applied to emission controls, it can be argued that the terms are broad enough to include an entire IGCC plant, which integrates coal gasification, synthesis gas cleaning, combined cycle, and emission control technologies to achieve clean use -- with, e.g., reduced sulfur dioxide, nitrogen oxide, and mercury emissions -- of coal to generate electricity. However, it seems more likely that only certain elements (e.g., gasification and synthesis gas cleaning) of the plant will be treated as property subject to these provisions and that other elements (e.g., coal handling equipment and the combined cycle combustion and steam turbines) will not be included in such property.[164]

Indiana statute also includes other special provisions -- similar to the electricity-generating-plant certification provisions under IC 8-1-8.5-2 through 8-1-8.5-6.5 -- concerning approval of, and recovery of costs (including return of and on capital) associated with, clean coal technology. Under IC 8-1-8.7-3(a), a public utility (including a municipal utility) must apply for and obtain a certificate of public convenience and necessity before using clean coal technology at an electricity generating facility. The IURC must issue a certificate if the project offers "substantial potential of reducing sulfur or nitrogen based pollutants in a more efficient manner than conventional technologies in general use as of January 1, 1989." IC 8-1-8.7-3(b). In issuing a certificate, the IURC must make findings on the estimated project costs and on the expected "dispatching priority" for the project (IC 8-1-8.7-3(b)(8)), as well as findings that the public convenience and necessity will be served and that the project will use Indiana coal as the primary fuel or is justified in using non-Indiana coal. IC 8-1-8.7-4(b)(3). The IURC may modify or revoke the certificate in light of changes in the estimate of cost of, or need for,

[164] Indiana statute includes two other provisions (IC 8-1-2-6.1 and 8-1-2-6.7) affecting the timing of recovery of investment in clean coal technology. The IURC is required to allow recovery, "as operating expenses" (IC 8-1-2-6.1(c)), of "preconstruction costs (including design and engineering costs) associated with employing clean coal technology" that is certificated if the project uses and will continue to use Indiana coal as the primary fuel or is justified in using non-Indiana coal (IC 8-1-2-6.1(c)(2)). A utility may seek treatment of such costs as operating costs in a general rate case. 170 IAC 4-6-16. The provision allows these preconstruction costs to be recovered on a more timely basis than would treating them as capital expenditures to be amortized, e.g., over the useful life of the project. Under IC 8-1-2-6.7, clean coal technology is allowed a depreciation period, for rate making purposes, of not less than the lesser of 10 years or the property's useful economic life and not more than 20 years if the facility uses Indiana coal or shows justification for using non-Indiana coal. The provision in effect allows accelerated depreciation of such property. For example, clean coal technology with a useful life between 10 and 20 years may be depreciated over a period that may be as short as 10 years, while such technology with a useful life exceeding 20 years may be depreciated over a period ranging from 10 to 20 years.

clean coal technology. IC 8-1-8.7-5. If the project is cancelled due to modification or revocation of the certificate, the utility may recover its "investment in the technology, along with a reasonable return on the unamortized balance." IC 8-1-8.7-6. However, costs in excess of the approved costs in the certificate may be recovered only if there is a showing that the excess costs were "necessary and prudent" and there was no "fraud, concealment, or gross mismanagement" by the utility. Id.

After certification of the clean coal technology, the IURC must conduct, if requested by the utility, an ongoing review of the construction and costs of the project as construction progresses. IC 8-1-8.7-7(b). The IURC has issued such certificates with ongoing review (under IC 8-1-8.7-7(b)) for nitrogen oxides control equipment, allowed recovery (under IC 8-1-2-6.6) of the return on capital for additional CWIP on such equipment at six-month intervals, and coordinated the ongoing review proceedings with the six-month updates for recovery of return on capital for CWIP. See e.g., Southern Indiana Gas and Electric Co., 2001 WL 1708778 at 14-15 (IURC Aug. 29, 2001) and PSI Energy, Inc., 2003 WL 21004706 (IURC Jan. 29, 2003). Upon approval of construction and costs in the ongoing review, the inclusion in the rate base of that part of the clean coal technology cannot be challenged "on the basis of excessive cost, inadequate quality control, or inability to employ the technology." IC 8-1-8.7-7(c). If construction and costs are disapproved in the ongoing review, the IURC may modify or revoke the certificate. If, as a result, the project is cancelled, the public utility can recover its previously approved investment plus a reasonable return, absent fraud, concealment, or gross mismanagement. IC 8-1-8.7-7(d). The utility has the option of having the IURC review construction and costs only after completion of the project. However, costs exceeding the costs in the certificate may be included in rate base only if shown to be "necessary and prudent," while costs within the certificate amount can be challenged "only on the basis of inadequate quality controls." IC 8-1-8.7-8.

Upon completion of the project, the utility may dispatch it in accordance with the dispatch priority set forth in the certificate, and such dispatching "shall not be considered to be in conflict with" the requirements for recovery of costs through a fuel adjustment clause (under IC 8-1-2-42). IC 8-1-8.7-9. Presumably this means that such dispatching may not be used as a basis for challenging recovery of fuel costs on the ground that the utility failed to make "every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible." IC 8-1-2-42(d)(1).

As noted above, the provisions for certification and cost recovery for clean cost technology (IC 8-1-8.7-3 through 8-1-8.7-9) are similar to the general certification and cost recovery provisions (IC 8-1-8.5-2 through 8-1-8.5-6.5) applicable to all new electricity generating facilities. For electricity generating facilities that will use clean coal technology, both sets of provisions apply. IC 8-1-8.7-10. For example, the Wabash gasification facility was certificated under both IC 8-1-8.5-1, et seq. and 8-1-8.7-1, et seq.. PSI Energy, Inc., 143 PUR4th 521, 542, 1993 WL 328722 (IURC May 26, 1993).

Apparently, no facilities certificated under IC 8-1-8.5-1, et seq. or IC 8-1-8.7-1, et seq. have been terminated and so the provisions concerning recovery of costs for cancelled plant have not yet been applied.

Finally, under two relatively new Indiana statutory provisions, IC 8-1-8.8-11 and 8-1-8.8-12, the IURC has broad, additional authority. Specifically, the IURC must encourage "clean coal and energy projects" by providing certain financial incentives if the projects are "reasonable and necessary."[165] IC 8-1-8.8-11(a). "Clean coal and energy projects" include: new energy generating facilities using clean coal technology, or advanced emission reduction technology for existing energy generating facilities, that are fueled primarily by coal or gas derived from coal from the Illinois Basin; projects for transmission to serve new energy generating facilities; projects using alternative energy sources such as renewables; and the purchase of fuels produced by a coal gasification facility in Indiana. IC 8-1-8.8-2. "Clean coal technology" under this provision includes technology that "directly or indirectly" reduces emissions "associated with the combustion or use of coal" and not in general commercial use at the same or greater scale in the U.S. as of November 15, 1990. IC 8-1-8.8-3(1) and (2). "New energy generating facilities" include new construction, repowering, or capacity expansion begun after July 1, 2002 that is "dedicated primarily to serving Indiana retail customers." IC 8-1-8.8-8(2)(B). The types of financial incentives that the IURC must provide include: timely recovery of construction and operating costs; authorization of up to three additional percentage points on return on equity; incentives (e.g., timely cost recovery and additional return on equity) for purchase of fuels produced by a coal gasification facility in Indiana; and incentives for development of alternative energy sources. IC 8-1-8.8-11(a). If a utility applies for financial incentives under this provision, the IURC must make a determination of eligibility for such incentives within 120 days, unless the utility does not cooperate fully in the proceeding. IC 8-1-8.8-11(d).

The IURC is also required to provide financial incentives for "new energy generating facilities" in the form of "timely recovery" (e.g., through a retail rate adjustment mechanism) of "costs incurred in connection with the construction, repowering, expansion, operation, or maintenance of the facilities." IC 8-1-8.8-12(a). Specifically, the IURC must allow recovery of costs associated with qualified utility system property if "the expected costs...and the schedule for incurring those costs are reasonable and necessary." IC 8-1-8.8-12(d). Similarly, the IURC must allow recovery of costs associated with purchase of fuel produced by a coal gasification facility if the costs are

[165] West Virginia, another coal state using more traditional utility regulation, has a similar provision requiring the West Virginia Public Service Commission (WVPSC) to "authorize rate-making allowances for electric utility investment in clean coal technology facilities or electric utility purchases of power from clean coal technology facilities located in West Virginia" in order to encourage such investment. West Virginia Code (WVC) 24-2-1g(b). Apparently, the provision has not been used. However, West Virginia statute includes a similar provision for investment in alternative fuels. Under the latter provision, the WVPSC has approved "accelerated rate recovery of [natural gas vehicle] investments" (including cost of capital) by gas utilities through a rate surcharge on most customers. Hope Gas, Inc., 160 PUR4th 512, 515, 1995 WL 310052 (WVPSC 1995).

"reasonable and necessary." IC 8-1-8.8-12(e). The term "timely recovery" in IC 8-1-8.8-12(a), as well as in IC 8-1-8.8-11(a), seems to encompass, inter alia, inclusion of construction work in progress in the rate base in order to allow for ongoing recovery of cost of capital for such construction and recovery of these and other costs through an adjustment clause (rather than through a rate case).

The IURC has coordinated its application of IC 8-1-8.7-3 through 8-1-8.7-9 and IC 8-1-8.8-11 and 8-1-8.8-12 in cases involving nitrogen oxides emission controls undertaken by some utilities. As discussed above, the IURC issued certificates of public convenience and necessity for the emission control projects and agreed to conduct ongoing review during construction. Further, the IURC approved not only adjustment-clause recovery of the return on capital during construction of such projects, but also adjustment-clause recovery of depreciation and operation and maintenance costs for the projects once the emission control projects go into service. See, e.g., Southern Indiana Gas and Electric Co., 2003 WL 21048981 at 4-5 (IURC Jan 2, 2003); Northern Indiana Public Service, 2002 WL 32089927 at 4-9; and Indianapolis Power & Light, 2002 WL 32091040 at 3-8. This approach ensures a dedicated stream of revenues covering all costs -- starting with return on capital on construction work in progress and continuing with return of and on capital and operating costs -- of the emission control projects.[166]

It seems that Indiana statute authorizes the IURC to adopt the same approach for new IGCC plants under the 3Party Covenant. Such a plant clearly seems to qualify as a new electricity generating facility and as clean coal technology eligible for certification and ongoing review under IC 8-1-8.5-2 through 8-1-8.5-6.5 and IC 8-1-8.7-3 through 8-1-8.7-9. In addition, such a plant clearly seems to qualify for: inclusion of construction work in progress in rate base; and for adjustment-clause recovery of return on capital during construction and of capital investment, return on capital and operating costs after commencement of plant service, under IC 8-1-2-6.8, 8-1-8.8-11, and 8-1-8.8-12. (The provision in IC 8-1-8.8-2 that Illinois Basin coal must be used for generation facilities under IC 8-1-8.8-11 is likely to be interpreted as unlawful and inapplicable. See General Motors, 654 N.E.2d at 763-67.) This approach will provide an assured revenue stream for full cost recovery for IGCC plants, consistent with the 3Party Covenant. See Sections 8.3, 9.3, and 9.4 below.

[166] Minnesota, another state using more traditional utility regulation, takes a different approach to encouragement of clean coal technology by entitling an "innovative energy project" (e.g., an IGCC plant proposed for the taconite region of the state) to enter into a long-term power purchase contract with a major utility in the state, with the terms subject to Minnesota Public Utilities Commission (MPUC) review. Minnesota Statutes (MS) 216B.1694(2)(a)(7). See also MS 216B.1694((2)(a)(8) (making project eligible for renewable development grant); and MS 216B.1693(a) and (c) (requiring utility to purchase at least 2 percent of its power supply for retail customers from "clean energy technology" found by the MPUC to be "a least-cost resource" (including the "innovative energy project" unless found to be contrary to the public interest)).

8.12. Kentucky.

Jurisdiction.

Kentucky has largely retained a more traditional approach to electric industry regulation. Kentucky statute provides the Kentucky Public Service Commission (KPSC) with authority to regulate any "utility", i.e., any person (except a municipality) that owns, controls or operates or manages a facility used or to be used for "generation, production, transmission, or distribution of electricity to or for the public, for compensation, for lights, heat, power, or other uses." Kentucky Revised Statutes Annotated (KRSA) 278.010(3)(a). Rural electric cooperatives are not excluded from the KPSC's jurisdiction.

In light of the Kentucky legislature's express determination that it is in the public interest to divide the state into geographic areas with one retail electric supplier for each certified territory (KRSA 278.016), the KPSC is required to set boundaries of the certified territory for each retail electric supplier based on the service areas as of 1972 (KRSA 278.017). Each retail electric supplier has an "exclusive right to furnish retail electric service to all electric consuming facilities" in its certified territory and must not provide service to customers in the certified territory of another retail electric supplier. However, if a supplier fails to provide adequate service to an electric consuming facility, the KPSC may authorize another supplier to provide the service. KRSA 278.018(1).

Further, no person may begin providing utility service "to or for the public" or begin construction of any plant for furnishing utility service without a certificate of public convenience and necessity. KRSA 278.020(1). There is an exception from this requirement for a retail electric supplier for "service connections to electric-consuming facilities" in its certified territory and for "ordinary extension of an existing system in the usual course of business." Id. A determination of public convenience and necessity requires findings of a need for a new facility to meet service requirements and an absence of wasteful duplication and multiplicity of physical properties. In considering an application for a certificate "to construct a base load electric generating facility," the KPSC may "consider the policy of the General Assembly to foster and encourage use of Kentucky coal by electric utilities" serving Kentucky. Id. See Kentucky Utilities Co. v. Public Service Commission of Kentucky, 252 S.W.2d 885, 890 (Ky. App. 1952) and Kentucky Utilities Co. v. Public Service Commission Kentucky, 390 S.W.2d 168 (Ky. App. 1965) (concerning findings necessary for issuance of certificate). A certificate must be exercised within one year in order to remain valid.

Ratemaking process: rate changes; test period; rate base; and rate of return.

A utility must charge "fair, just and reasonable rates" for services (KRSA 278.030(1)), and the rates must be set forth in filed rate schedules (KRSA 278.160). See Stephens v. South Central Bell Telephone Co., 545 S.W.2d 927, 931 (Ky. 1976) (citing FPC v. Hope

in explaining that rates must be just and reasonable). Rates cannot generally be changed by the utility without 30 days notice, but the KPSC may shorten the notice period to 20 days for good cause. KRSA 278.180(1). The KPSC may suspend the effectiveness of the new rates for up to five months from the proposed effective date for the rates if the rates are based on costs from a historical test period and up to six months if the rates are based on projected costs from a forward-looking test period. If the KPSC does not complete its proceeding and issue a decision by the end of five or six months (whichever is applicable), the utility may begin charging the new rates, subject to refund. However, if the KPSC determines that, because of the failure to allow the rates to become effective before the end of the suspension period, the "company's credit or operations will be materially impaired or damaged," then the KPSC may let the rates become effective sooner. KRSA 278.190(2). The KPSC must issue a decision on a proposed rate increase within 10 months of the filing of the proposed increase. KRSA 278.190(3).

The KPSC may investigate any rate upon complaint that the rate is "unreasonable or unjustly discriminatory" or on the KPSC's own motion. KRSA 278.260. If the KPSC finds a rate in unjust or unreasonable, the KPSC must prescribe a just and reasonable rate for the future. KRSA 278.270.

Kentucky statute sets forth basic procedures for setting just and reasonable rates. Rates may be based on costs from a historical test period or a forward-looking test period. For proposed general rate increases, the KPSC must allow a utility to use a historical test period of 12 calendar months before the proposed rate filing or a forward-looking test period of 12 calendar months after the maximum suspension period. KRSA 278.192(1). The historical test period data may be adjusted for "known and measurable changes." 807 Kentucky Administrative Regulations Service (KAR) 5:001 §10(1)(a). A rate filing using a forward-looking period must provide data on nine months before the filing, including at least six months of actual data. KRSA 278.192(2). The KPSC generally bases rates on a historical, rather than a forward-looking, test period. But see Kentucky-American Water Co., 1993 WL 595984 at 18 (KPSC Nov. 19, 1993) (stating that use of a forward-looking test period tend "to decrease the risk that...[a utility] will not earn its allowed return" and taking this into account in setting return on equity).

Further, the KPSC may "ascertain and fix the value of the whole or any part of the property of any utility in so far as the value is material to the exercise of the jurisdiction of the commission." KRSA 278.290(1). The KPSC may make "revaluations from time to time and ascertain the value of all new construction, extension and additions to the property." Id. It is not clear, from the face of the provision, whether revaluations can apply in cases other than new construction, extension, or addition, e.g., to unchanged, existing property. In fixing the value of property, the KPSC must "give due consideration to the history and development of the utility and its property, original cost, cost of reproduction as a going concern, capital structure, and other elements of value recognized by the law of the land for ratemaking purposes." Id. On its face, KRSA 278.290(1) does not limit determinations of rate base to facilities that are used and useful.

On the contrary, the provision has been held to be "broad enough" to allow the KPSC to consider additional factors in the case of a rural electric cooperative with a new coal-fired plant producing more electricity than needed at that time to meet the cooperative's customer load. National-Southwire Aluminum Co. v. Big Rivers Electric Cooperative, 785 S.W.2d 503, 512 (Ky. App. 1990). Although in previous cases the KPSC had limited rate base to facilities that were "used and useful" (see, e.g., Fern Lake Co. v. Public Service Commission, 357 S.W.2d 701 (Ky. App. 1962) and Blue Grass State Telephone Co. v. Public Service Commission of Kentucky, 382 S.W.2d 81 (Ky. App.1964)), the Court upheld in National-Southwire Aluminum consideration by the KPSC of other factors. In particular, the Court held that the KPSC could consider "replacement cost, debt retirement, operating costs, and at least some excess capacity in order to insure continuation of adequate service during periods of high demand and some potential for growth and expansion." National Southwire Aluminum, 785 S.W.2d at 512. The KPSC could also consider "whether expansion investments were prudently or imprudently made, and whether a particular utility is investor owned or a cooperative operation." Id. The Court noted that the coal-fired plant was not like "an incomplete nuclear plant" and was "not a useless facility." Under these circumstances, the Court upheld the KPSC's order setting rates high enough for the rural electric cooperative to pay its debt on the plant under a workout plan, which plan allowed the cooperative to avoid bankruptcy and provided a longer pay-back period and lower interest rate. Id. at 513. As the Court explained, there is "no litmus test" for setting fair, just, and reasonable rates and "no single prescribed method to accomplish the goal." Id.

Once the rate base valuation is determined, the KPSC must set the rate of return on that rate base. See Public Service Commission of Kentucky v. Continental Telephone Co. of Kentucky, 692 S.W.2d 794, 798 (Ky. 1985) (citing Bluefield Water Works & Improvement as standard for determining rate of return). The method for setting rate of return may vary depending on the method used to value the rate base. Citizens Telephone Co. v. Public Service Commission of Kentucky, 247 S.W.2d 510 (Ky. App. 1952) (explaining that, where rate base is valued at reproduction costs, allowed return on capital may be lower than where rate base is valued at original cost).

Adjustment clauses.

Rates may include an automatic adjustment clause for costs of fuel used by the utility and fuel associated with purchased power. The adjustment clause may provide for periodic (monthly) adjustment per kilowatthour of sales equal to changes in fuel costs. Fuel costs under the adjustment clause include: the cost of fuel consumed in the utility's plants or the utility's share of fuel costs at jointly owned or leased plants; the cost of fuel that "would have been used in [such] plants suffering forced generation or transmission outages, but less the cost of fuel related to substitute generation" resulting from such forced outages (807 KAR 5:056 §1(3)(a)); and certain costs of fuel associated with purchased power (807 KAR 5:056 §1(3)(b) and (c)). Every six months, the KPSC

reviews the charges under the adjustment clause to correct for "improper calculation or application of the charges or improper fuel procurement practices." 807 KAR 5:056 §1(11). Every two years the KPSC reviews the past operation of the adjustment clause and may "disallow improper expenses" and reestablish the adjustment clause. 807 KAR 5:056 §1(12).

Moreover, the KPSC offered to adopt for certain electric utilities an optional earnings sharing mechanism (ESM) under which the amount of earnings above or below a specified earnings band is shared (on a 60 percent to 40 percent basis) between investors and ratepayers through an automatic monthly credit or surcharge (as appropriate) that is trued up annually in an expedited proceeding. Costs covered by the fuel adjustment clause (as well as the below-described environmental surcharge) are excluded from the calculations for the earnings sharing mechanism. Kentucky Utilities, 2000 WL 309957 at 20-21 (KPSC Jan. 7, 2000). This approach has been adopted for some utilities in the state. See Kentucky Utilities Co., 2000 WL 872715 at 5-6 (KPSC Jun. 1, 2000) and Louisville Gas and Electric Co., 2000 WL 872716 at 5-6 (KPSC Jun. 1, 2000). The KPSC is currently evaluating whether the earnings sharing mechanism is providing the intended incentives to improved performance. See Kentucky Utilities Co., 2003 WL 23336337 (Nov. 20, 2003) and Louisville Gas and Electric Co., 2003 WL 23336338 (Nov. 20, 2003). Apparently, the earnings sharing mechanism will be discontinued as of 2004.

Special provisions for costs of environmental compliance.

Under legislation enacted in 1992, the KPSC is required (starting January 1, 1993) to allow recovery through a rate surcharge, which is analogous to a fuel adjustment clause, for utilities' costs of complying with certain environmental requirements. Specifically, Kentucky statute provides that, "[n]otwithstanding any other provision of this chapter [278]," a utility "shall be entitled to the current recovery of its costs of complying with the Federal Clean Air Act as amended and those federal, state, or local environmental requirements which apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal" in accordance with a utility's approved compliance plan.[167] KRSA 278.183(1). The compliance costs include "a reasonable

[167] Colorado, another coal state using more traditional utility regulation, has a similar provision stating that a public utility is "entitled to fully recover the air quality improvement costs that it prudently incurs" under a voluntary agreement with the Colorado Department of Public Health and Environment to reduce emissions. Colorado Revised Statutes (CRS) 40-3.2-102(1). The Colorado Public Utilities Commission must determine "an appropriate method of cost recovery that assures full cost recovery." CRS 40-3.2-102(3). See, e.g., Public Service Co. of Colorado, 1999 WL 716478 (Jun. 16, 1999) (recommended decision approving recovery of air quality improvement costs (including capital investment, return on capital, and operating costs) through "Air Quality Improvement Rider," a nonbypassable charge applied to all retail deliveries by utility); and Public Service Co. of Colorado, 2002 WL 32073085 (Dec. 19, 2002) (approving recovery of air quality improvement costs, i.e., early retirement of higher-emitting units and emission controls on other units, through "Air Quality Improvement Rider").

return on construction and other capital expenditures and reasonable operating expenses" (including operation and maintenance, taxes, and depreciation) "for any plant, equipment, property, facility or other action to be used to comply." Id. The costs must not be already reflected in existing rates. KRSA 278.183(2).

A utility may request such recovery through a rate "surcharge" applied starting in the second month after the month in which the costs to be recovered are incurred. At least 30 days in advance of commencing the surcharge, the utility must file a notice of intent to submit a plan for complying with the applicable environmental requirements and must subsequently file the plan. Id. Within six months of the filing, the KPSC must review the compliance plan and the rate surcharge, including the rate of return on the environmental capital expenditures. In addition, each monthly rate surcharge must be filed with the KPSC 10 days before going into effect. The KPSC must review the rate surcharge every six months and make a "temporary adjustment" to disallow any amounts that are "not just and reasonable" and to "reconcile past surcharges with actual costs." KRSA 278.183(3). The KPSC must also conduct review every two years and "disallow improper expenses" and incorporate the surcharge amounts into the utility's general rates. Id. In conducting these reviews, the KPSC does not carry out a full review of the utility's overall financial condition as is required in a general rate case. Instead, the KPSC separately considers the relevant environmental costs, in a manner analogous to the review of fuel costs in a review of a fuel adjustment clause. Kentucky Industrial Utility Customers, Inc. v. Kentucky Utilities Co., 983 S.W.2d 493, 498 (Ky. Sup. Ct. 1998). On appeal, these provisions were upheld, with the Court holding that the Kentucky legislature had a legitimate interest in promoting "the use of Kentucky coal so as to provide jobs and other economic benefits in Kentucky" and to balance investor and ratepayer interests in a way that reflects that interest. Id. at 497; see also Kentucky Utilities Co., 2000 WL 309957 at 25 (KPSC Jan. 7, 2000) (holding that KRSA 278.183 provides a "stand alone cost recovery mechanism" separate from a general rate case).

The KPSC has approved use of this cost recovery mechanism for recovery of rate of return on construction work in progress and plant in service, depreciation, and operating costs for emission controls or waste handling through an environmental surcharge. See, e.g., Kentucky Utilities Co., 2003 WL 21246131 at 3-7 (KPSC Feb. 11, 2003) (allowing surcharge recovery for such costs for sulfur dioxide emission controls, but rejecting surcharge recovery of landfill site costs because costs were too uncertain for KPSC to determine reasonableness and cost-effectiveness of landfill site); and Kentucky Utilities Co., 2003 WL 21246128 at 2-4 (KPSC Feb. 11, 2003) (allowing surcharge recovery for such costs for fly and bottom ash pond dike).

Although the provision for surcharge recovery of the "costs of complying" with environmental requirements has been applied to emission controls or emission disposal property, it may be argued that the entire IGCC plant -- which integrates coal

gasification, synthesis gas cleaning, combined cycle, and combustion emission control technologies to achieve clean use of coal to generate electricity -- is a means of "complying" with environmental requirements. However, it seems more likely that only certain elements (e.g., gasification and synthesis gas cleaning) of the plant will be treated as related to environmental compliance and that the costs of the other elements (e.g., coal handling equipment and combined cycle combustion and steam turbines) will be excluded from surcharge recovery.

The applicability of this provision (KRSA 278.183) is not stated as broadly as the Indiana provisions (e.g., IC 8-1-8.8-11 and 8-1-8.8-12) applying to "clean coal and energy projects" and "new energy generating facilities." While the Indiana provisions clearly cover an entire IGCC plant, the scope of the Kentucky provision is problematic. In addition, the Kentucky provision appears to require allowance of more rapid, but perhaps less certain, cost recovery than the Indiana provisions. Specifically, under KRSA 278.183 the utility may adjust the surcharge each month and pass through costs on an ongoing basis without upfront prudence review by the KPSC, but subject to KPSC review every six months and every two years. It seems that the KPSC can disallow costs and require refund of the pass-through as late as two or more years after the pass-through occurs, since the biennial review proceeding may take a number of months to complete. Further, although Kentucky statute establishes an entitlement to recovery for environmental compliance costs "[n]otwithstanding any other provision of" state utility law (KRSA 278.183(1)), it is not clear to what extent the KPSC will disallow recovery of costs of environmental compliance property that does not operate, or is not used, as intended under the environmental compliance plan. In contrast, the IURC allows the utility to adjust the charge under the adjustment clause every six months and to pass through the costs only after IURC review. It appears that once the IURC approves six-months' worth of capital expenditures, re-evaluation of the reasonableness of the expenditures is generally not allowed, in the absence of "fraud, concealment, or gross mismanagement," even if the facility is not completed. IC 8-1-8.7-7(d). See Sections 8.3, 9.3, and 9.4 below.

8.13. New Mexico

Jurisdiction.

In 1999, New Mexico enacted provisions for deregulating retail electricity generation and sales in 2001. See New Mexico Statutes Annotated (NMSA) 62-3A-1 through 62-3A-23. However, the New Mexico legislature subsequently postponed the commencement date for deregulation until 2007 and then, in a separate action, entirely repealed the deregulation provisions. New Mexico thus continues to retain a more traditional approach to electric industry regulation.

New Mexico statute establishes a state policy requiring the "regulation and supervision" of public utilities "to the end that reasonable and proper services shall be available at fair,

just and reasonable rates, and to the end that capital and investment may be encouraged and attracted so as to provide for the construction, development and extension, without unnecessary duplication and economic waste, of proper plants and facilities for the rendition of service to the general public and to industry." NMSA 62-3-1(B). The New Mexico Public Regulation Commission (NMPRC) has jurisdiction over every public utility. "Public utilities" include any individual, firm, partnership, or company "not engaged solely in interstate business" that owns, operates, leases, or controls "any plant, property, or facility for the generation, transmission or distribution, sale or furnishing to or for the public of electricity for light, heat or power or other uses." NMSA 62-3-3(G)(1). However, unless a municipality elects to have its municipal utility regulated by the NMPRC, the municipal utility is excluded from NMPRC rate jurisdiction. NMSA 62-6-5. Further, the NMPRC has jurisdiction to review a rate change made: by rural electric generation or transmission cooperatives only if three or more New Mexico member utilities in the rural electric cooperative object to the rate change (NMSA 62-6-4(D)); and by other rural electric cooperatives if one or more members object (NMSA 62-8-7(G)).

A public utility may not begin construction or operation of "any public utility plant or system or of any extension to any plant or system" without first obtaining from the NMPRC "a certificate that public convenience and necessity require or will require such construction or operation." NMSA 62-9-1. In deciding whether to issue such a certificate, the NMPRC must give due regard to the public convenience and necessity, including, e.g., the avoidance of "unnecessary duplication and economic waste." NMSA 62-9-6. The requirement for a certificate does not apply to any extension that: is within the public utility's service area (as of July 13, 1941) or within or to an area already served by the utility, "necessary in the ordinary course of its business"; or is in a contiguous area not receiving similar service from another public utility. NMSA 62-9-1 See Sandel v. New Mexico Public Utility Commission, 980 P.2d 55, 58 (N.M. 1999) (describing general regulatory approach in New Mexico of giving vertically integrated utilities exclusive control of generation, transmission, and distribution in specific geographic areas and setting their rates).

The NMPRC has "general and exclusive power and jurisdiction to regulate and supervise every public utility in respect to its rates and service regulations and in respect to its securities." NMSA 62-6-4(A). However, the NMPRC regulates the "sale, furnishing or delivery of …electricity" to a public utility for resale and the "sale, furnishing or delivery of coal, uranium or other fuels by any affiliated interest" to a public utility only to the extent necessary for the NMPRC to determine that the cost to the public utility is "reasonable" and the methods of delivery of electricity are "adequate." NMSA 62-6-4(B) and (C).

Ratemaking process: rate changes; test year; rate base; and rate of return.

Every rate charged by a public utility must be "just and reasonable" (NMSA 62-8-1) and filed with the NMPRC (NMSA 62-8-3). A public utility cannot change its rates "except

after thirty day's notice" to the NMPRC. NMSA 62-8-7(B). However, "for good cause shown," the NMPRC may allow a rate change to take effect without such prior notice. Id. The NMPRC must suspend operation of the new rates, if a hearing on the rates is necessary, for nine months after the effective date of the rate change and may extend the suspension for another three months. The NMPRC must "hear and decide cases with reasonable promptness." NMSA 62-8-7(C). In reviewing the rates, the NMPRC may determine "just and reasonable" rates or may require the utility to file new rates "designed" to produce revenues determined by the NMPRC to be just and reasonable. NMSA 62-8-7(D). The NMPRC may investigate a rate upon complaint that the rate is unjust or unreasonable or on its own motion and may issue orders affecting such rates. NMSA 62-10-1.

New Mexico statute does not specify the methodology to be used in setting just and reasonable rates. Otero County Electric Cooperative, Inc. v. New Mexico Public Service Commission, 774 P.2d 1050 (N.M. 1989). However, in setting rates, the NMPRC generally follows "the traditional elements of the ratemaking process and the establishment of the total revenue requirement," i.e., determination of cost of operation, rate base (which is the value of property "owned by the utility rendering service to the public") less depreciation, and rate of return. Hobbs Gas Co. v. New Mexico Public Service Commission, 616 P.2d 1116, 1118 (N.M. 1980); see also PNM Gas Service, 1 P.3d 383, 391 (N.M. 2000) (stating that NMPRC must set rates that are neither "unreasonably high so as to unjustly burden ratepayers with excessive rates nor unreasonably low so as to constitute a taking of property without just compensation or a violation of due process by preventing the utility from earning a reasonable rate of return on its investment"); and Sandel, 980 P.2d at 64 (reversing NMPRC's approval of market-based rates, rather than rates determined through ratemaking process).

With regard to determination of operating costs, the NMPRC evaluates a utility's costs for a historical year and "uses the utility's past experience as a guide to the utility's future revenue requirement." PNM Gas Service, 1 P.3d at 391. The test period may be a historical test year of 12 consecutive months ending not more than 150 days before the filing of new rates (adjusted for annualization and known and measurable changes) or a future test year of 12 consecutive months after the last 12 months of actual experience (adjusted for known and measurable changes and projected changes). New Mexico Administrative Code (NMAC) 17.9.530.7(S)(1) and (2). See, e.g., Gas Co. of New Mexico, 35 PUR4th 106, 127 (NMPRC Feb. 4, 1980) (adjusting historical test period data for known, measurable, and certain changes). The NMPRC generally uses the same time period as the test year for evaluating operating costs, revenues, and capital investment. See, e.g., Public Service Co. of New Mexico, 111 PUR4th 313, 369-70, 1990 WL 488711 (NMPRC Apr. 12, 1990).

In valuing utility property and business in order to determine rate base, the NMPRC must "give due consideration to the history and development of the property and business of the particular public utility, to the original cost thereof, to the cost of reproduction as a

going concern, to the revenues, investment and expenses of the utility in this state and otherwise subject to the commission's jurisdiction and to other elements of value and rate-making formulae and methods recognized by the laws of the land for rate-making purposes." NMSA 62-6-14(A). In making determinations concerning public utility rates or service, the NMPRC may "change its past practices or procedures" if the change is justified by "substantial evidence" in the record. NMSA 62-6-14(C). Thus the NMPRC is not bound to use any specific method of property valuation but cannot rely solely on original cost. Hobbs Gas, 616 P.2d at 1119-20.

In particular, the NMPSC is not required to limit the rate base to property that is used and useful. New Mexico Industrial Energy Consumers v. New Mexico Public Service Commission, 725 P.2d 244, 248-49 (N.M. 1986) (upholding the NMPRC's approach of allowing utilities to establish "inventory" of new electricity generation capacity above 20 percent reserve margin and to include plant plus accrued return on capital in rate base when plant becomes necessary to serve New Mexico customers). However, the Court in New Mexico Industrial Energy Consumers noted that the NMPRC had found that the specific utility decision at issue in that case (i.e., whether to build electricity generation capacity) was prudent and that the NMPRC's approach resulted in new capacity coming into rate base only when the capacity was put into service. Id. at 249; see also Public Service of New Mexico, 111 PUR4th at 318, 1990 WL 488711 (explaining that, under inventory approach, reasonableness and appropriateness of costs of plant could be challenged and, if any costs were disallowed, return on capital associated with disallowed costs would also be disallowed).

Although the NMPRC is not required to include, in rate base, only plant that is used and useful, the NMPRC generally treats the "used and useful" criterion as an important, albeit not dispositive, factor in determining what property to include in rate base. For example, in the case of property held for future use, the NMPRC has allowed such property to be included in rate base and thus in rates either if the property would be put into use shortly after the end of the test period for the rates or if the utility demonstrated that it had a plan to use the property in the foreseeable future and that inclusion in rate base would benefit ratepayers without imposing an undue burden. See, e.g., El Paso Electric Co., 29 PUR4th 427, 429-30 (NMPRC Jun. 8, 1979).

The NMPRC has similarly taken a flexible approach in deciding whether, and to what extent, to include construction work in progress in the rate base. When faced with the question of whether to include CWIP on a nuclear plant in rate base, the NMPRC, at least initially, did not allow inclusion of any such CWIP. See, e.g., El Paso Electric Co., 23 PUR4th 131, 137 (NMPRC Dec. 15, 1977) (denying inclusion of CWIP on nuclear plant not scheduled to go into service for five years, based on company's assurance that ratepayer financing of CWIP was not necessary to complete the plant, but suggesting different result if denial would cause "extensive financial hardship"). Subsequently, the NMPRC elaborated its analysis of rate-base inclusion of CWIP, stating that the factors considered in determining whether to include CWIP in rate base were: whether the

construction program was reasonable; whether the construction could be financed without ratepayer participation before the plant was in service; and whether the construction was financed at the least cost. El Paso Electric, 29 PUR4th at 438-40 (denying inclusion of CWIP on nuclear plant, but approving CWIP on emission controls that would go into service during period that rates reflecting CWIP would be in effect). In El Paso Electric Co., 38 PUR4th 289, 340 (NMPRC July 24, 1980), the NMPRC further explained its criteria for inclusion of CWIP on a new electric generation plant in rate base, requiring an additional showing of "extensive financial hardship" to the utility and its customers without the inclusion of the CWIP in rate base. In that case, the NMPRC allowed in rate base some, but not all, of the CWIP on nuclear plant. In all these cases, the plants whose CWIP was allowed in rate base ultimately were completed and went into service; none of these were plants whose construction was started but was subsequently terminated.

The NMPRC has also taken a flexible approach to the application of the "used and useful" concept when addressing, in after-the-fact review, the extent to which completed excess capacity should be included in rate base. When a utility had a substantial amount of electricity generation capacity in excess of the amount needed to serve its retail customers reliably, the NMPRC rejected the approach of excluding from rate base all excess capacity as not being used and useful. Public Service Co. of New Mexico, 101 PUR4th 126, 169-75, 1989 WL 4185588 (NMPRC April 5, 1989), aff'd sub nom. New Mexico Industrial Energy Consumers v. New Mexico Public Service Commission, 808 P.2d 592 (N.M. 1991). Instead, the NMPRC considered both a flexible "used and useful test" and a "financial health test" to determine what portion of the excess capacity should be treated as "used and useful" and included in the utility's rate base. Public Service of New Mexico, 101 PUR4th at 162-63, 1989 WL 418588. The NMPRC noted that the remedies available for excess capacity range from total inclusion of the capacity in rate base to total exclusion from rate base and that a "fair result" often involves a "sharing of costs" between investors and ratepayers. Public Service of New Mexico, 101 PUR4th at 163, 1989 WL 418588. After considering factors such as what was the amount of excess capacity, how long the capacity would remain excess, whether inclusion of any of the excess capacity in rate base would be just and reasonable, and what would be the economic consequences (e.g., the effect on the utility's financial health) of the rate treatment of the excess capacity, the NMPRC decided to include some, and exclude some, of the excess capacity (which included nuclear plant).[168]

Subsequently, with regard to the utility's nuclear units that the NMPRC allowed to be included in rate base, the NMPRC resolved the issue of the prudence of the utility's investment by approving a settlement disallowing a portion of the return of and on capital for the units. Public Service Co. of New Mexico, 110 PUR4th 69, 90-92, 1990 WL

[168] Under New Mexico statute, a public utility may own or operate an electric generating plant that is not intended to provide retail electric service to New Mexico customers, whose costs are not included in rate base and so are not reflected in New Mexico retail electric rates, and that is not subject to the NMPRC's rate jurisdiction. The NMPRC must ensure that "the regulated business is appropriately credited by any off-system sales made from regulated assets." NMSA 62-6-4.3(A).

488859 (NMPRC Mar. 6, 1990), aff'd sub nom. Attorney General of State of New Mexico v. New Mexico Public Service Commission, 808 P.2d 606 (N.M. 1991). However, in a later case, the NMPRC left open the possibility of additional disallowance of the cost of these units. Specifically, the NMPRC stated that it could "give no more assurances on the future ratemaking treatment" of the nuclear plants than "for any other utility asset in rate base" and, if the units become "wholly or partially unused or unuseful" in the future, additional return of or on capital for the units could be disallowed. Public Service Co. of New Mexico, 157 PUR4th 540, 563-64, 1994 WL 736326 (NMPRC Nov. 28, 1994). But see Public Service of New Mexico, 111 PUR4th at 330, 1990 WL 488711 (stating that utility need not show that these nuclear units warrant continued recovery of and on capital in next rate case); cf. Town of Norwood, Massachusetts v. Federal Energy Regulatory Commission, 80 F.3d 526, 531 (D.C. Cir. 1996) (upholding FERC allowing full recovery of unamortized capital investment, return on capital, and CWIP on nuclear plant that was in service for 31 years and has been prudently shutdown).

In setting the rate of return to be applied to the jurisdictional rate base, the NMPRC considers "current economic conditions, the present cost of capital, the rate of return of other enterprises having corresponding risk, and the principles of law governing the determination of just and reasonable rate for utilities." Southern Union Gas Co. v. New Mexico Public Service Commission, 503 P.2d 310, 313 (N.M. 1972). For example, a reasonable rate of return is one that provides an opportunity to receive just compensation for investment and fulfills the statutory goal in NMSA 62-3-1(B) of enabling a utility to attract capital. PNM Gas Service, 1 P.3d at 391. See also Behles v. New Mexico Public Service Commission, 836 P.2d 73, 80 (N.M. 1992) (stating that, in setting rate of return, there is a significant "zone of reasonableness…between utility confiscation and ratepayer extortion").

Adjustment clauses.

In 1975, the NMPRC adopted, for a major utility in the state, a new ratemaking methodology referred to as "cost-of-service indexing" or "COSI," under which rates were automatically adjusted on a periodic (at first, quarterly) basis when rate of return on the average book value of common equity for the period fell outside a range of 13.5 to 14.4 percent. Construction work in progress on environmental controls on existing plant, but not on new electricity generating plant, was allowed in rate base and thus in the equity portion of the rate base. See Public Service Co. of New Mexico, 8 PUR4th 113, 121-24 (NMPRC Apr. 22, 1975); see also Public Service Co. of New Mexico, 50 PUR4th 416, 418-23 (NMPRC Dec. 30, 1982) (describing history of cost-of-service indexing).

The NMPRC adopted cost-of-service indexing in order to enable the utility to attract new capital for new coal-fired and nuclear plants, which the NMPRC noted were more capital intensive than gas- and oil-fired plants. The NMPRC stated that coal and nuclear fuels had several advantages over gas and oil in terms of cost and reliability. Gas costs were

increasing rapidly as compared to coal, and nuclear generation appeared to be cheaper than any fossil-fuel generation. Further, use of the enormous coal reserves and the uranium reserves in the U.S. would result in greater energy reliability and less dependence on foreign fuel. Public Service of New Mexico, 8 PUR4th at 119; see also Public Service of New Mexico, 101 PUR4th at 175, 1989 WL 418588 (explaining that fuel diversity minimizes risk of adverse changes in price or supply of a particular fuel resulting from unanticipated events, such as an oil embargo or adverse environmental impacts from fuel use). Because traditional cost-based ratemaking could not keep up with ongoing increases in utility costs, capital investment and cost of capital were not being recovered, and new capital investment was being discouraged. Public Service of New Mexico, 8 PUR4th at 119-21. Moreover, the NMPRC found that as the "earning stability and reliability of an energy utility are reduced, the market responds by increasing its cost of capital." Id. at 121.

According to the NMPRC, cost-of-service indexing would reduce risk and regulatory lag by restoring earnings stability and reliability, without reducing the utility's incentive "to resist cost increases and to effect economies." Id. at 132. Although rates were automatically adjusted, the NMPRC retained the right to review the rates using traditional cost-based ratemaking.

In 1979, the NMPRC reviewed the use of cost-of-service indexing. According to the NMPRC, cost-of-service indexing had the positive impacts of reduced cost of common equity and of improved ability to attract capital, but had the negative impacts of inadequate incentives to resist cost increases and effect economies and of reduced regulatory scrutiny due to overburdening of the NMPRC. Public Service of New Mexico, 50 PUR4th at 421-422. The NMPRC therefore changed the adjustment period for cost-of-service indexing from a quarterly to an annual adjustment period and based each new adjustment factor on a period consisting of ten months of actual data and two months of projected data. Further, each new adjustment factor was made subject to refund if an objection to any cost data underlying the calculation of return on common equity was received and accepted for hearing by the NMPRC. In the event of such an objection, the utility had the burden of demonstrating the prudence and reasonableness of each expense item subject to the objection. Id. at 422 and 427.

Finally, in 1982, the NMPRC terminated the use of cost-of-service indexing because the New Mexico legislature adopted a statutory provision (NMSA 62-8-7(E)) that the NMPRC interpreted as barring cost-of-service indexing. Id. at 423. The NMPSC also found that, while capital costs had been reduced, cost-of-service indexing resulted in less regulatory scrutiny and possibly "fueled [the utility's] ability to construct excessive capacity without concern for the long-term risks inherent to ratepayers and shareholders in such an endeavor." Id. at 451.

NMSA 62-8-7(E) provides that: "Except as otherwise provided by law, any increase in rates or charges for the utility commodity based upon cost factors other than taxes or cost of fuel, gas, or purchased power…shall be permitted only after notice and hearing, as

provided by" NMSA 62-8-7(B) and (C) (requiring 30 day's notice and authorizing the NMPRC to suspend operation of new rates pending hearing for up to 12 months). The NMPRC is required to issue regulations "governing the use of tax, fuel, gas or purchased power adjustment clauses" and providing for consideration of several matters. NMSA 62-8-7(E). The matters that must be considered include: whether a particular adjustment clause is consistent with the purposes of utility regulation; what specific mechanism for recovery of such costs is to be used; what costs should be included; what procedures should be used to avoid inclusion of inappropriate costs; what methods should be used by the NMPRC for determining the "propriety" of costs "in a timely manner" (NMSA 62-8-7(E)(3)); and what adjustment period should be used. The NMPRC may eliminate or condition an adjustment clause if this action is consistent with the purposes of utility regulation and "will not place the affected utility at a competitive disadvantage." NMSA 62-8-7(F). The NMPRC must provide for "variances" and "separate examination of a utility's adjustment clause based upon that utility's particular operating characteristics." Id.

The NMPRC issued regulations implementing the adjustment clause provisions in NMSA 62-8-7(E). When making an initial application for a fuel and purchased power adjustment clause, a utility must show that: the cost of fuel and purchased power is a "significant percentage of the total cost of service" (NMAC 17.9.550.17(A)(1)); the cost "periodically fluctuates and cannot be precisely determined in a rate case" (NMAC 17.9.550.17(A)(2)); and the utility's policies and practices are designed to assure electricity is generated and purchased "at the lowest reasonable cost" (NMAC 17.9.550.17(A)(3)). In addition, the utility must show that the proposed adjustment clause is consistent with the goals of "adequate regulatory review" (NMAC 17.9.550.6(A)), "stability of utility earnings" when costs rise and "prompt credits" to customers when costs decline (NMAC 17.9.550.6(B)), and assurance of collection of "actually expended" costs (NMAC 17.9.550.6(C)). See NMAC 17.9.550.17(A) (requiring showing of consistency with purposes of rule). After approval of an adjustment clause, the utility must file every two years for continuation of the adjustment clause. The adjustment clause is deemed approved 30 days after the continuation filing unless the adjustment clause is suspended by the NMPRC. NMAC 17.9.550.18.

Prior to passage of NMSA 62-8-7(E), the NMPRC had allowed fuel and purchased power adjustment clauses in order to allow utilities to keep up with rapidly rising fuel costs, without repeated filings for increased rates and jeopardizing of cash flow. See ,e.g., Southwestern Public Service Co., 27 PUR4th 302, 320-21 (NMPRC Dec. 5, 1978). In applying the new statutory provisions, the NMPRC has allowed some, but not all, utilities to use fuel and purchased power adjustment clauses. For example, for one utility, the NMPRC eliminated entirely the fuel adjustment clause, and the accompanying credits for revenues from off-system electricity sales, that had previously been in effect. Public Service Co. of New Mexico, 157 PUR4th 579, 583, 1994 WL 736329 (NMPRC Nov. 28, 1994). The NMPRC explained that it considers the trade-off between "earnings stability"

and “incentives” to minimize costs in determining whether to approve fuel adjustment clauses. Id. at 586. Because of the decline in inflation and the fact that fuel cost increases were more in line with inflation, the NMPRC terminated the utility’s adjustment clause.

Other utilities that demonstrated continued, rapid increases in fuel or purchased power costs or the potential for such increases have been allowed to use fuel and purchased power adjustment clauses. See, e.g., Texas-New Mexico Power Co., 2000 WL 1425094 at 8 (NMPRC Aug. 15, 2000) (approving fuel and purchased power adjustment clause with limitation on month-to-month fluctuations).

Retail electric competition: restructuring; nonbypassable charges; and provider of last resort.

Until New Mexico’s repeal of the utility deregulation legislation, the state’s more traditional approach to utility regulation (described above) was to be replaced by an approach requiring competitive retail electric generation and sales. The repealed legislation and implementing regulations are summarized below.

Under the repealed legislation, each public utility had to divide into at least two corporations in order to separate: “supply service and energy-related service consisting of generation and power supply facilities, operations and services and energy-related facilities,” to be made available to the public “on a competitive unregulated basis”; and transmission and distribution services “to be made available on a regulated basis.” NMSA 62-3A-8(B). Corporate separation could be accomplished by creating separate affiliated companies or separate unaffiliated companies or by selling assets to third parties. Unregulated service could not be provided by a regulated company. NMSA 62-3A-8(C). A utility was not required to “divest itself of any of its assets” that it owned or leased as of the effective date of the retail-electric-competition legislation. NMSA 62-3A-8(A).

Each public utility had to file a “transition plan” to implement deregulation of retail electric sales service. NMSA 62-3A-6. The transition plan had to include, inter alia: separation of “supply service and energy-related assets” from distribution and transmission assets consistent with NMSA 62-3A-8 (NMSA 62-3A-6(A)(1)); unbundled cost of service (NMSA 62-3A-6(A)(2)); projected “stranded costs” and “transition costs” (NMSA 62-3A-6(A)(8)); and “non-bypassable wires charges” for recovery of stranded and transition costs (NMSA 62-3A-6(A)(9)). “Stranded costs” were the difference between the net present value of generation-related “regulated revenue requirements” as of the commencement of retail sales competition that were recoverable in rates and the revenues “that could be earned from selling the same generation-related services” at competitive rates. NMSA 62-3A-3(Z). “Transition costs” were defined as the remaining costs of restructuring that were reasonable, prudent, and nonmitigable. NMSA 62-3A-3(CC).

The NMPRC was required to provide for recovery by a public utility of 50% of the company's stranded costs. However, recovery of up to 100% could be provided, but only if the NMPRC found that recovery exceeding 50% was in the "public interest" (NMSA 62-3A-6(B)(1)), "necessary to maintain financial integrity of the public utility" (NMSA 62-3A-6(B)(2)), and "necessary to continue adequate and reliable service" (NMSA 62-3A-6(B)(3)) and would not increase residential or small business rates during the stranded-cost recovery period (NMSA 62-3A-6(B)(4)).

The NMPRC had to set the nonbypassable wires charges for recovery of stranded and transition costs. With regard to stranded costs, the wires charges could be imposed for up to five years (or longer for nuclear decommissioning costs) and had to be "equitably designed in a competitively neutral manner." NMSA 62-3A-7(B)(3). With regard to transition costs, the wires charges could be modified in order to achieve full recovery, with crediting to customers for any overcollection. NMSA 62-3A-7(D). The wires charges would be imposed on every customer of a public utility, but only for system benefits for customers of rural electric distribution cooperatives or municipal utilities. NMSA 62-3A-14(A).

The public utility's transition plan also had to include: "standard offer service tariffs" for residential and small business customers that did not select a power supplier (NMSA 62-3A-6(A)(5)); and a proposed "procurement process or other process for selection of power supply for standard offer service" and rate setting procedures (NMSA 62-3A-6(A)(6)). A public utility had to design its electricity procurement to assure supply at the "lowest, reasonable price consistent with reliability, availability and portfolio requirements balancing local economic and environmental impacts." NMAC 17.9.591.10(A). Competitive bidding had to be used to produce supply for standard offer service unless the utility demonstrated that "another means [was] in the public interest." NMAC 17.9.591.10(B). Costs under the standard service offer had to be recovered through a purchased power adjustment clause. NMAC 17.9.591.9(C).

Special provisions for renewal-energy electric generation.

New Mexico recently passed a statute (Renewable Energy Act, Chapter 65, Laws of 2004) (REA) adopting a renewable portfolio standard for electric generation in the state. Underlying the statute are findings by the state legislature that, inter alia, use of renewable energy provides opportunities to "promote energy self-sufficiency, preserve the state's natural resources and pursue an improved environment in New Mexico" (REA Section 2.A(1)) and that public utilities should recover their "reasonable costs" of meeting the requirements of the statute (REA Section 2.A(4)). Within certain cost thresholds, each public utility's retail sales in New Mexico are required to comprise an increasing percentage, over time, of renewable energy: by 2006, five percent must be renewable energy, increasing one percent per year to ten percent in 2011 and thereafter. REA Section 4.A. The NMPRC must establish a system of renewable energy certificates that can be used to show compliance with such renewable portfolio requirements.

Certificates are generally owned by the generator of renewable energy and may be traded, sold, or otherwise transferred. Certificates are retired when used to meet a utility's renewable portfolio requirements and, if unused, may be carried forward for up to four years. REA Section 5. A public utility must "recover, through the rate-making process, the reasonable costs of complying with the renewable portfolio standard." REA Section 6.A. Each utility must submit an annual procurement plan for the next year, and costs consistent with an approved plan are deemed reasonable. REA Section 4.D and 6.A.

Unlike Indiana and Kentucky, New Mexico does not have provisions for ongoing review, approval, and recovery of capital expenditures, return on capital, and operating costs for new generation-related plant or equipment. Moreover, New Mexico statute and NMPRC precedent include certain provisions or policies that seem to be inconsistent with the provision of an assured revenue stream for new IGCC plants under the 3Party Covenant. These provisions or policies include: a statutory prohibition of the use of adjustment clauses, except for fuel, purchased power, and taxes; NMPRC precedent for re-evaluation of past "used and useful" determinations for electricity generating plant; and NMPRC precedent strictly limiting inclusion of CWIP in rate base. See Sections 8.3, 9.3, and 9.4 below.

8.2. States with competitive retail electricity generation and sales.

8.21. Ohio.

Jurisdiction.

Until January 1, 2001 when the Public Utilities Commission of Ohio (PUCO) began to implement "competitive retail electric service" under the state's utility deregulation statute, Ohio followed a more traditional approach of regulating electric utilities as vertically integrated monopolies with designated service areas. The PUCO is granted "power and jurisdiction to supervise and regulate public utilities." Ohio Revised Code Annotated (ORCA) 4905.04(A). Ohio statute defines "public utility" as including any "electric light company, when engaged in the business of supplying electricity for light, heat, or power purposes to consumers" (ORCA 4905.03(4)), with exceptions for municipal utilities and non-profit electric light companies, and utilities owned and operated exclusively by and for their customers (e.g., rural electric cooperatives) (ORCA 4905.02). An electric light company (also referred to as an "electric supplier") has a "certified territory" in which the company has the "exclusive right to furnish electric service to all electric load centers." ORCA 4933.83(A). In general, an electric light company's "certified territory" is its service area as of 1978. See ORCA 4933.82(B). The company may not extend electric service to load centers in another company's certified territory. ORCA 4933.83(A). (Under the regulatory system in place until 2001, "electric service" included retail electric generation, which starting in 2001, was exempted from "electric service." See ORCA 4933.81(F).) However, municipalities retain the right to

generate, transmit, distribute, or sell electricity. ORCA 4933.87; see Toledo Edison Co. v. City of Bryan, 737 N.E.2d 529, 533 (Ohio 2000) (holding that municipalities may generate or purchase electricity for residents but not for the purpose of selling outside municipal boundaries).

Before construction of a "major utility facility," including any electricity generating plant of 50 MW or more (ORCA 4906.01), can commence, a certificate must be issued for the facility by the PUCO's power siting board. ORCA 4906.04. There is an exception for the certificate requirement for replacement of an existing facility "with a like facility." Id. In issuing a certificate, the board must make findings on the need for the facility and the nature of the facility's probable environmental impact and on whether the facility will serve the "public interest, convenience, and necessity." ORCA 4906.10(A)(6).

Ratemaking process: rate changes; test period; rate base; and rate of return.

The PUCO determines "just and reasonable rates" for public utility service (which until 2001 included retail electric service). ORCA 4905.22 and 4909.15(A). A public utility must file an application to establish or change any rate. ORCA 4909.18. When the PUCO fails to issue a final order on a proposed rate increase within 275 days, the rate goes into effect subject to refund, if the utility provides an "undertaking" payable to the PUCO in order to ensure refunds will be made as appropriate. If the PUCO does not issue a final order within 545 days, the utility has no refund requirement for amounts collected after the latter deadline. ORCA 4909.42. The PUCO may determine that a rate being charged or proposed to be charged is unjust or unreasonable and set the just and reasonable rate to be charged. ORCA 4909.15(D).

In determining just and reasonable rates for a public utility, the PUCO must determine: a "fair and reasonable rate of return" on the value of public utility property (ORCA 4909.15(A)(2)); and the "cost to the utility of rendering the public utility service" for a test period (ORCA 4909.15(A)(4)). Determination of a "fair and reasonable rate of return" is "prospective" and must be based on current, not historical, data. Babbit v. Public Utility Commission of Ohio, 391 N.E.2d 1376, 1383 (Ohio 1979). The test period for determining a public utility's cost of service is generally a 12-month period starting six months before the application for rates or a rate change is filed and not ending more than nine months after such filing. The PUCO can order use of a different test period. ORCA 4909.15(C). Generally, test year revenues and expenses may not be adjusted in order to set rates. Dayton Power & Light Co. v. Public Utility Commission of Ohio, 447 N.E.2d 733, 736-37 (Ohio 1983). The exception is where adjustment is necessary to prevent "an anomaly in the ratemaking equation, making the test year unrepresentative for ratemaking purposes." Board of Commissioners of Montgomery County v. Public Utility Commission of Ohio, 438 N.E.2d 111, 113 (Ohio 1982).

The property value on which rates are based is generally the value of the property that is "used and useful for the service and convenience of the public." ORCA 4909.04(A). The property value must be determined as the original cost (ORCA 4909.05(C) through (G)),

less depreciation and contributions of capital (ORCA 4909.05(H) and (I)), of property used and useful as of "the date certain determined by" the PUCO. ORCA 4909.15(A)(1). See, e.g., Office of Consumers' Counsel v. Public Utility Commission of Ohio, 391 N.E.2d 311 (Ohio 1979) (rejecting inclusion in rate base of investment in nuclear plant that was not providing beneficial service to ratepayers as of the date on which utility property was valued for rate purposes, although the plant provided beneficial service as of a later date). These provisions were applied to deny or limit recovery of capital investment and return on capital for cancelled nuclear plants. See, e.g., Office of Consumers' Counsel v. Public Utility Commission of Ohio, 423 N.E.2d 820, 827 (Ohio 1981) (holding that PUCO lacks statutory authority to treat expenditures for cancelled nuclear plant as amortized operating costs because, even though investment decision and decision to cancel were prudent when made, expenditures were "an investment that never provided any service whatsoever to the utility's customers"); Dayton Power & Light, 447 N.E.2d at 740-45 and Cleveland Electric Illuminating Co. v. Public Utilities Commission of Ohio, 447 N.E.2d 746 (Ohio 1983), cert. den., 464 U.S. 802 (1983) (affirming PUCO's denial of cancelled nuclear plant expenditures as amortized costs); and City of Cincinnati, 620 N.E.2d 826 (explaining that, where uncompleted nuclear plant was converted to coal-fired plant, PUCO disallowed recovery of non-used-and-useful portion of capital investment in nuclear plant and allowed recovery of remainder of capital investment as associated with coal plant). In setting return on equity, the PUCO can take into account the increased risk to investors that results from the inability to recover costs of cancelled plant. Office of Consumers' Counsel v. Public Utilities Commission of Ohio, 447 N.E.2d 749, 753-54 (Ohio 1983).

However, the PUCO can include in rates an "allowance for construction work in progress" up to 10 percent of the total valuation of the project involved. The project must be at least 75 percent completed before the allowance can be included in rates. ORCA 4909.15(A)(1). A provision, repealed effective January 1, 2000, increased the allowance under this provision to 20 percent of the total valuation if the project was for pollution control equipment.[169] [170] The PUCO has "broad discretion" in applying this provision,

[169] Illinois, another coal state that has now deregulated retail electricity sales, has a similar provision for recovery of return on capital for construction work in progress for "pollution control devices for the control of sulfur dioxide emissions." 220 Illinois Compiled Statutes (ICS) 5/9-214(f).

[170] Pennsylvania, another coal state that has now deregulated retail electricity sales, has provisions favoring the use of coal, e.g., a provision for inclusion in rate base of CWIP for up to 50% of the cost of increasing the capacity to use coal in existing coal-fired plants. 66 Pennsylvania Consolidated Statutes (PCS) 514(c). In addition, the Pennsylvania Public Utility Commission (PPUC) must issue regulations requiring utilities to increase their generating capacity through increased capacity to use coal at existing coal-fired facilities where "economically feasible" and "beneficial to ratepayers" and establishing a "special cost recovery and shared benefits procedure" as an incentive for such capacity increases. 66 PCS 514(a) and (b). The PPUC also must order conversion of existing oil- or gas-fired units to coal or coal-derived fuel, unless conversion is not feasible, the converted unit cannot meet environmental requirements, or the converted unit would be more costly to ratepayers. Reasonable and prudent costs of a required conversion are recoverable, even if the conversion or operation of the converted unit is "ultimately prevented by factors beyond the utility's control," and can be included in rate base during construction. 66 PCS 517(a) and (d). Finally, a utility can construct a new nuclear or oil- or gas-fired unit only with PPUC approval. The PPUC can approve this only

which, for example, is not subject to any test period restriction. Columbus & Southern Ohio Electric Co. v. Public Utilities Commission of Ohio, 460 N.E.2d at 1111 (Ohio 1984). The allowance may be included in rates for no more than 48 months, with the possibility of an extension of up to 12 more months for good cause. If the project is cancelled, abandoned, or terminated, then the allowance must be excluded from rates "immediately" and offset against future revenues. ORCA 4909.15(A)(1). See Columbus & Southern Ohio Electric, 460 N.E.2d 1108 (upholding PUCO order reversing inclusion of construction work in progress in rate base in light of indefinite suspension of plant construction).

Before its repeal effective January 1, 2001, ORCA 4913.05 provided another exception to a strict "used and useful" requirement. If the PUCO approved a plan for compliance with certain requirements of the Acid Rain Program under Title IV of the Clean Air Act, the utility incurred costs for emissions control equipment under the plan, and the PUCO subsequently withdrew approval of the plan due to "substantial or extraordinary changes in circumstances," then the PUCO could approve recovery of "reasonably incurred" costs for the equipment.[171] ORCA 4913.05(G) (repealed effective Jan. 1, 2001). Return on capital for construction work in progress for such equipment could be recovered through a surcharge on the utility's rates. ORCA 4090.19.2 (repealed effective Jan. 1, 2001). The provision in ORCA 4913.05(G) was apparently never applied.

Adjustment clauses.

Prior to repeal effective January 1, 2001 of the statutory adjustment-clause provisions discussed in this section, the PUCO could allow pass-through of costs of fuel used by the utility and fuel associated with purchased power in a fuel adjustment clause. See ORCA 4905.01(G) (definition of "fuel component"; repealed effective Jan.1, 2001) and 4909.15.9 (limiting purchased power costs in fuel adjustment clause to fuel used for generation; repealed effective Jan. 1, 2001); see also Montgomery Count Board of Commissioners v. Public Utilities Commission of Ohio, 503 N.E.2d 167 (Ohio 1986) (barring inclusion, in fuel adjustment clause, of non-fuel costs not expressly authorized for such recovery in statute); and Cleveland Electric Illuminating Co., 154 PUR4th 418, 428, 1994 WL 526118 (PUCO Aug. 10, 1994) (rejecting inclusion of demand-side management costs in fuel adjustment clause because of insufficient "nexus" between demand-side management programs and reduction in per unit fuel costs and explaining

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if no sites are reasonably available for a comparable unit using coal or coal-derived fuel in compliance with environmental requirements or if such comparable unit would be more costly for ratepayers. 66 PCS 519 and 521.

[171] Pennsylvania similarly has a provision for PPUC review and approval of each utility's plan, upon request by the utility, to bring coal-fired units into compliance with the Acid Rain Program. 66 PCS 530(a) and (b). Upon approval of the plant, reasonable and prudent compliance costs for "desulfurization devices, clean coal technologies, or similar facilities designed to maintain or promote" (66 PCS 530(d)(2)(ii)) coal use are "recoverable costs of service" (66 PCS 530(d)(2)). Such costs qualify as "nonrevenue-producing investments" that are not required, under 66 PCS 1315, to be "used and useful" in order to be included in rate base or otherwise included in rates. 66 PCS 530(d)(3).

that without such a "connection" requirement any equipment that increased fuel efficiency could be included in fuel adjustment clause).

The fuel component was calculated based on base period fuel costs and purchased power costs (i.e., fuel used to generate purchased power or total purchased power costs for power not exceeding the utility's incremental fuel cost for its own generation). Ohio Administrative Code (OAC) 4901:1-11-01(I) (definition of "economic power") and 4901:1-11-04(B) through (D). A reconciliation procedure was used to correct any over- or under-recovery of costs. OAC 4901:1-11-06.

The PUCO required electric utilities to make a showing every six months, in an expedited hearing, that the fuel costs were "fair, just, and reasonable." OAC 4901:1-11-11(B). The PUCO could defer inclusion of costs in the fuel component if their appropriateness was "questionable," pending submission of evidence that they were "properly includable." OAC 4901:1-11-08(B). The PUCO was required to review the fuel component at least annually, or upon request, if changes in acquisition and delivery costs or in system operations caused or could cause at least a 20 percent change in the fuel component. ORCA 4905.30.1 (repealed effective Jan. 1, 2001). The electric utility had to charge its most recently approved fuel component until the PUCO changed the fuel component. OAC 4901:1-11-12.

Ohio coal research and development costs could also be included in the fuel component.[172] ORCA 4905.30.1 and 4909.19.1(B) (repealed effective January 1, 2001); see also OAC 4901:1-11-03(B). The Ohio Coal Development Office is charged with encouraging, promoting, and supporting "siting, financing, construction, and operation of commercially available or scaled facilities and technologies, including, without limitation, commercial-scale demonstration facilities and, when necessary or appropriate to demonstrate the commercial acceptability of a specific technology, up to three installations within this state utilizing the specific technology, to more efficiently produce, beneficiate, market, or use Ohio coal." ORCA 1551.32(A)(1). Priority is to be given to technologies that "enable maximum use of Ohio coal in an environmentally acceptable, cost-effective manner." ORCA 1551.32(B). The Ohio Coal Development Office reviews proposals for coal research and development projects to be supported by a state loans, load guarantees, or grants and may recommend recovery of the costs of such a project through the utility rates. While, on the face of the statute, the recovery through utility rates seems to be limited to projects undertaken by a gas or natural gas company (ORCA 4905.30.4), the costs could be recovered by an electric utility as well through its fuel component. See OAC 4901-11-05. In one case, a gas utility was allowed to recover its share of costs associated with emission controls under a coal research and

[172] Illinois similarly has fuel adjustment clause provisions favoring the use of coal. Specifically, Illinois allows inclusion as a fuel cost, recoverable in a fuel adjustment clause, "any fees paid by the utility for the implementation and operation of a process for desulfurization of the flue gas when burning high sulfur coal at any location" in Illinois. 220 ICS 5/9-220(a).

development project at an electricity generating plant. See East Ohio Gas Co., 1994 WL 73500 at 2 (PUCO Feb. 3, 1994) (approving recovery of gas utility's costs in gas reburn and sulfur dioxide and nitrogen oxide control projects at electricity generating plant as coal research and development costs included in adjustment clause).

Retail electric competition: restructuring; and nonbypassable charges for transition costs.

Ohio's retail electric competition statute makes the above-described regulatory system inapplicable to retail electric generation and sales starting in 2001 and requires functional unbundling of electricity distribution from electricity generation and transmission. The Ohio statute declares that it is state policy to, inter alia: "[e]nsure the availability to consumers of adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service" (ORCA 4928.02(A)); "[e]ncourage innovation and market access for cost-effective supply- and demand-side retail electric service" (ORCA 4928.02(D)); and "[e]nsure effective competition in the provision of retail electric service by avoiding anti-competitive subsidies" (ORCA 4928.02(G)). The shift to deregulated retail electric service is phased in, with a five-year transition period ("market development period") in which costs associated with deregulation may be recovered.

"Retail electric service" is defined as any service "involved in supplying or arranging for the supply of electricity to ultimate consumers" in Ohio, from "the point of generation to the point of consumption." ORCA 4928.01(A)(27). This includes generation, aggregation, power marketing, power brokerage, transmission, distribution, ancillary service, metering, and billing and collection. Id. Of these components of retail electric service, the portion that is required by statute to be "competitive" includes "retail electric generation, aggregation, power marketing, and power brokerage services." ORCA 4928.03. The PUCO may determine that additional components of retail electric service must also be competitive. ORCA 4928.04.

Starting January 1, 2001, "competitive retail electric service" is not subject to "supervision or regulation" by the PUCO under ORCA 4901 through ORCA 4909 (which are the provisions establishing the above-described, more traditional regulatory system) with limited exceptions concerning, e.g., discriminatory rates and conditions, certified territories, and service reliability and public safety. Control of transmission facilities in Ohio must be transferred to qualifying independent transmission entities. ORCA 4928.12. Further, each electric utility (e.g., each electric light company engaged in both competitive and noncompetitive retail electric service) must implement a "corporate separation plan" approved by the PUCO. ORCA 4928.17(A). The plan must: include the provision of competitive retail electric service through a "fully separated affiliate" (ORCA 4928.17(A)(1)); satisfy the public interest in "preventing unfair competitive advantage and…abuse of market power" (ORCA 4928.17(A)(2)); and ensure that the company will not extend "undue preference or advantage" to any affiliate, division, or part of its business that supplies competitive retail electric service (ORCA

4928.17(A)(3)). The PUCO may, for good cause, shown, approve "for an interim period" a plan that does not provide for a fully separated affiliate but that complies with "functional separation requirements." ORCA 4928.17(C).

Ohio statute requires that, after a transition period, each electric distribution utility (i.e., each electric utility that provides retail electric distribution service) provide "a market-based standard service offer of competitive retail electric services" within its certified territory (ORCA 4928.14(A)) and the option to purchase such services through a "competitive bidding process" (ORCA 4928.14(B)). The PUCO must ensure that competitive retail electric service is provided at "compensatory, fair, and nondiscriminatory" prices, terms, and conditions if the PUCO determines that there is a "decline or loss of effective competition" for such service provided by an electric utility. ORCA 4928.06(B). Further, the PUCO is authorized to "resolve abuses of market power by any electric utility that interfere with effective competition." ORCA 4928.06(E)(1). In particular, the PUCO may take measures to ensure that retail electric generation service is provided "at reasonable rates" in a "transmission constrained area" in a utility's certified territory if the PUCO finds that the utility engaged in "abuse of market power" that is "not adequately mitigated" by any "independent transmission entity controlling the transmission facilities." ORCA 4928.06(E)(2).

Each electric utility must submit for approval by the PUCO a "utility transition plan." ORCA 4928.31(A). The plan includes the major components for the transition to competitive retail electric service. First, the plan must include a plan for unbundling utility rates, as well as the above-described corporate separation plan. The electric utility is required to file separate (i.e., "unbundled") rate components for electricity generation, transmission, and distribution to be charged during the market development period. ORCA 4928.34. During the market development period, the utility functions as the provider of last resort in that the utility is required to make available to all retail customers in the utility's certified territory "a standard service offer of all competitive retail electric services necessary to maintain essential electric service to consumers including a firm supply of electric generation service." ORCA 4928.35(D). If another supplier fails to provide service, the suppliers' retail customers default to the standard service offer until the customers chose another supplier. Id. In order for the unbundled rates to be approved, the total revenue from all unbundled rates must be capped and equal the total revenues from the utility's most recent bundled rates. ORCA 4928.34(A)(6).

Second, the utility transition plan may include an application for the opportunity to receive revenues for transition costs. During the market development period, the electric utility receives such revenues from competitive retail electric service in its certified territory through: the approved, unbundled rates paid by its customers for retail electric generation; and an approved, "nonbypassable and competitively neutral transition charge" paid, per kilowatthour purchased, by those customers in its certified territory who obtain retail electric generation from another company. ORCA 4928.37(A)(1)(b). The transition charge is not payable on electricity supplied by a municipal utility to retail

customers if the municipal utility provides transmission or distribution through its facilities and was operating as of January 1, 1999. The charge is also not payable on electricity produced and consumed in Ohio by a self-generator (i.e., a facility producing electricity "primarily for the owner's consumption" (ORCA 4928.01(33))). ORCA 4928.37(A)(2)(b).

In essence, the utility is allowed to impose, as a nonbypassable charge, a charge for access to the wires by retail customers. The only costs that may be included in the transition charge are the "just and reasonable transition costs" that: were "prudently incurred"; are "legitimate, net, verifiable, and directly assignable or allocable to retail electric generation service" in Ohio; and are "unrecoverable in a competitive market" but otherwise recoverable by the utility. ORCA 4928.39(A) through (D). These costs include the costs of "regulatory assets," which are unamortized, non-recurring expenses whose recovery was deferred by the PUCO (e.g., deferred taxes and employee benefit and retirement costs), as well as stranded generation assets. ORCA 4928.39. The transition charge includes "shopping incentives" to encourage the development of effective competition in retail electric generation service, e.g., sufficient incentives to induce shifting to a company other than the electric utility by at least 20 percent of the retail electric service load by the end of 2003. ORCA 4928.40(A). The transition charges may be reviewed and adjusted no more often than annually. ORCA 4928.40(B)(1). The portions of the charge that are based on regulatory assets are subject to adjustment only prospectively and generally only after December 31, 2004. ORCA 4928.39.

The nonbypassable charge provides an opportunity for the utility to recover transition costs, but actual revenues from the charge may be more or less than these costs. AK Steel Corp. v. Public Utilities Commission of Ohio, 765 N.E.2d 862, 866 (Ohio Ct. App. 2002). The electric utility is "wholly responsible" for "how to use" transition revenues and for "whether it is in a competitive position" after the market development period. ORCA 4928.38. However, the PUCO may impose requirements to ensure that the revenues are used to "eliminate the allowable transition costs" during the market development period and are not available for use to achieve undue competitive advantage by the electric utility. ORCA 4928.39.

Third, the utility transition plan may include a plan for transferring control of the electric utility's transmission facilities to an independent entity. ORCA 49028.31(A). In the absence of an approved independent transmission plan, the PUCO must order transfer of the transmission facilities to an independent entity to be operational by the end of 2003. ORCA 4928.35(G).

The PUCO has approved utility transition plans for a number of electric utilities. Under these approved plans, the utilities were generally allowed to retain ownership of their electricity generating plants, transfer control of their transmission facilities, and recover transition costs through a nonbypassable transition charge. See, e.g., Monongahela Power Co., 2000 WL 1873291 at 2 (PUCO Oct. 5, 2000), reh'g den., 2000 WL 33175454 (PUCO Nov. 21, 2000) (approving utility transition plan with transfer of operational

control of transmission assets and with transition charge for regulatory assets); Columbus Southern Power Co., 2000 WL 1873290 at 5-6 and 21-22 (PUCO Sept. 28, 2000), clarified, 2000 WL 33191552 (PUCO Nov. 21, 2000), stay den., Columbus Southern Power Co., v. Public Utility Commission of Ohio, 745 N.E.2d 1052 (Ohio 2001) (approving utility transition plan with transfer of operational control of transmission assets and future transfer of ownership of transmission and distribution assets to new affiliates and with transition charge for regulatory assets and (except for switching customers) stranded generation assets)); Dayton Power and Light Co., 2000 WL 1751554 at 5-9 and 12-13 (PUCO Sept. 21, 2000), reh'g den., 2000 WL 33118630 (PUCO Nov. 30, 2000) (approving utility transition plan with transfer of operational control of transmission assets and future transfer of ownership of transmission and generation assets to affiliates and with transition charge for regulatory assets); Cincinnati Gas & Electric Co., 2000 WL 1751385 at 4, 7-8, and 38-40 (PUCO Aug. 31, 2000), reh'g den., 2000 WL 1876395 (PUCO Oct. 18, 2000) (approving utility transition plan with transfer of operational control of transmission assets, with conduct of competitive retail service through affiliate and future transfer of ownership of generation assets, and with transition charge for regulatory assets (including future purchased power costs)); and FirstEnergy Corp., 203 PUR4th 102, 113 and 121-26, 2000 WL 1791792 (PUCO Jul. 19, 2000), reh'g den., 2000 WL 1876876 (PUCO Sept. 13, 2000) (approving utility transition plan with transfer of operational control of generation assets to business unit and future division of ownership of company assets among generation, transmission and distribution, and support services affiliates and with transition charge for regulatory assets and stranded generation assets). See also Ohio Edison Co., 233 PUR4th 349, 2004 WL 1493955 (Jun. 9, 2004) (indicating need for additional filing by utility concerning corporate separation). Although the utility transition plans provided, in the future, for ownership of generation assets by a separate company from the company owning transmission or distribution assets, only one of the utilities has completed such a corporate separation, and it is not clear when such corporate separations will take place.

After the market development period (which terminates by the end of 2005 or sooner, if approved by the PUCO), the electric utility will no longer receive "transition revenues" or "equivalent revenues." ORCA 4928.38. However, the PUCO may allow recovery of revenue requirements for regulatory assets through December 31, 2010. ORCA 4928.40(A).

Retail electric competition: provider of last resort and related nonbypassable charges.

Also after the market development period, each electric utility must provide, "on a comparable and nondiscriminatory basis within its certified territory, a market-based standard service offer of all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of electric generation service" (ORCA 4928.14(A)) and the option to purchase competitive retail electric service at a price determined through a "competitive bidding process" in which any

generation supplier may participate (ORCA 4928.14(B)). However, the PUCO recently indicated that a competitive retail generation market will likely not be "fully mature and robust" in Ohio by the end of 2005 and approved negotiated standard-service-offer rates for a utility for 2006-2008. Ohio Edison Co., 233 PUR4th 349, 2004 WL 1493955. See also Dayton Power and Light Co., 227 PUR4th 1, 18-19 and 23-25, 2003 WL 22142843 (PUCO Sept. 2, 2003), rehg. den. in relevant part, 2003 WL 22964799 (PUCO Oct. 22, 2003) (noting that PUCO had approved ending market development period on December 31, 2003, but extending period to December 31, 2005 due to lack of effective competition and approving negotiated standard-service-offer rates for 2006-2008). The electric utility is the provider of last resort in that, for its certified territory, if another supplier fails to provide electricity generation service for retail customers, service must be provided under the electric utility's standard service offer. There is no time limit on the requirement to function as the provider of last resort. See ORCA 4928.14(C). An electric distribution utility may require, pursuant to an approved tariff, a retail electric generation service provider to "issue and maintain a financial instrument" to protect against default in the provision of retail electric generation service. OAC 4901:1-24-08(A).

The PUCO has interpreted the provider-of-last resort requirement as providing a basis for imposing certain costs related to an electric utility's electricity generating plants on all retail electric generation customers, including those customers served by other electricity suppliers. Dayton Power and Light, 2003 WL 22964799 at 5 (stating that utility has "costs that are associated with the possible return of customers" and should be "compensated for these costs"). The costs (in that case, costs reflecting fuel price increases, compliance with environmental and tax requirements, and physical security and cyber-security) were allowed to be recovered up to a capped amount, through a rider (i.e., a "rate stabilization surcharge"). Id. The PUCO stated that, while it was not finding that these costs were provider-of-last resort costs, "the existence of [provider-of-last-resort] costs makes it reasonable to apply the [surcharge] to all customers." Dayton Power and Light, 227 PUR4th 1, 26, 2003 WL 22142843. See also Ohio Edison Co., 233 PUR4th 349, 2004 WL 1493955 (approving rate stabilization charge for all customers covering utility's risk (and not based on utility's costs) in providing provider-of-last-resort service at fixed rate during 2006-2008).

One electric utility has argued before the PUCO that the company should be able to pass through, in a nonbypassable charge, the costs of investment in electricity generating plant necessary to maintain a specified generation reserve margin. According to the utility, this charge will compensate for the company's statutory obligation, as the provider of last resort, to stand ready at all times to serve all retail load in its certified service territory. Initial Comments of the Cincinnati Gas & Electric Company, Case No. 03-93-EL-ATA at 8-16 (Mar. 4, 2003). The PUCO has not yet ruled on the utility's request.

The PUCO may also establish riders on the rates for retail electric distribution service. The riders may cover costs for assistance to low income customers or consumer education or costs for an energy efficient revolving loan fund. ORCA 4928.52; and

ORCA 4928.61. Like the nonbypassable charge for transition costs, the riders are wires access charges paid by retail customers. Ohio statute does not appear to currently authorize nonbypassable wires charges for any other types of cost.

In contrast with the more traditional electric industry regulatory systems in Indiana, Kentucky, and New Mexico, retail electric competition in Ohio generally puts the full risk of new electricity generating plant on investors and makes investors' recovery of costs subject to the operation of the electricity market. In general, this approach is inconsistent with the provision of an assured stream of revenues for new IGCC plants under the 3Party Covenant. See Sections 8.3, 9.3, and 9.4 below.

8.22. Texas.

Jurisdiction.

Until January 1, 2002 when the Public Utility Commission of Texas (TPUC) began implementing retail electric competition in most of the state under the state's utility deregulation statute, Texas followed a more traditional approach of regulating electric utilities as vertically integrated monopolies with designated service areas. The TPUC is granted "general power to regulate and supervise the business of each public utility," including each electric utility (Texas Utilities Code Annotated (TUCA) 14.001), and specifically has jurisdiction over "rates, operations, and services" of an electric utility (TUCA 32.001(a)). The term "electric utility" is defined generally as any person that "owns or operates for compensation in this state equipment or facilities to produce, generate, transmit, distribute, sell, or furnish electricity in this state." TUCA 31.002(6). However, there are several exceptions to the general definition, including a municipality, a qualifying facility, an exempt wholesale generator, a power marketer (i.e., a person who owns electricity for wholesale sale but owns no generation, transmission, or distribution facilities in the state and has no certificated service areas), a rural electric cooperative,[173] and a person owning or operating equipment "used primarily to produce and generate" electricity for his own consumption (TUCA 31.002(6)(J)(ii)). (As discussed below, the state's utility deregulation statute amended the definition of "electric utility" to add exclusions for a "retail electric provider" and a "power generation company.") Each municipality regulates local utility service within the municipality, with the TPUC exercising a review function, but municipalities may elect to have the TPUC exercise original jurisdiction over such utility service. TUCA 32.001(a)(2), 33.002, and 33.052.

An electric utility may not provide service to the public "under a franchise or permit" unless the company first obtains a certificate of convenience and necessity. TUCA 37.051(a). The TPUC may issue a certificate for a service area (or a facility) only if "necessary for the service, accommodation, convenience, or safety of the public." 16

[173] Before 1997, under certain circumstances, the TPUC could review the rates of rural electric cooperatives providing retail service. See TUCA 36.251 and 36.307.

Texas Administrative Code (TAC) 25.101(b). A certificate or certificate amendment is required for, inter alia, a change in service area or a new electricity generating unit "constructed, owned, or operated by a bundled electric utility." TAC 25.101(b)(2). Further, a "retail electric utility" may not provide service to an area where another "retail electric utility" is lawfully providing service unless the former company first obtains a certificate of convenience and necessity. TUCA 37.051(b). The TPUC may not grant a certificate if that would result in an area being "multiply certificated" unless the certificate holder is not, and is not capable of, providing adequate service. TUCA 37.060(h).

Until the provisions were repealed effective September 1, 1999, Texas statute required each electric utility to submit a preliminary, ten-year integrated resource plan including a forecast of demand and necessary supply. TUCA 34.021 and 34.022. After the plan was approved, the electric utility had to solicit bids in accordance with the plan and could receive bids from affiliates and request a certificate of "convenience and necessity" for "new rate-based generating plant." TUCA 34.051(b)(3). If bid solicitation and negotiation did not result in the resources necessary to meet supply-side needs under the plan, the utility could apply for a certificate of public convenience and necessity for a "utility-owned resource addition" not in the plan. TUCA 34.056.

After completion of the solicitation and negotiation process, the electric utility had to submit a proposed, final integrated resource plan for review by the TPUC. TUCA 34.103. Once a supply-side or demand-side contract was certified by the TPUC as part of the final plan, the TPUC had to treat payments under the contract as a "reasonable and necessary operating expense" for purposes of setting rates and could provide for "monthly recovery" of costs under the contract "as those costs [were] incurred." TUCA 34.104(e).

Ratemaking process: rate changes; test period; rate base; and rate of return.

The TPUC must ensure that the rates of an electric utility are "just and reasonable." TUCA 36.003(a). An electric utility must give notice of a proposed rate change at least 35 days before the effective date of the new rate. TUCA 36.102(a). The TPUC may suspend the rate change for up to 150 days after the date that the rate change would otherwise be effective. Thereafter, the rate may go into effect subject to refund if the electric utility provides a surety bond payable to the TPUC. TUCA 36.108(a)(2) and 36.110(a). Unless a hearing is in progress, if the TPUC fails to make a final determination before expiration of the suspension period, the TPUC is "considered to have approved the [rate] change." TUCA 36.108(c). For good cause shown, the TPUC may allow a rate change that increases revenues by the greater of $100,000 or two and one-half percent to go into effect before the end of the 35-day notice period. TUCA 36.101 and 36.104. In addition, if, on its own motion or on complaint, the TPUC finds that existing rates of a utility are "unreasonable or in violation of law", the TPUC must set just and reasonable rates to be charged in the future. TUCA 36.151(a).

The TPUC must approve rates that provide "overall revenues at an amount that will permit the utility a reasonable opportunity to earn a reasonable return on the utility's invested capital used and useful in providing service to the public in excess of the utility's reasonable and necessary operating expenses." TUCA 36.051. The TPUC bases its rate determinations on the cost of providing service in a historical test year, adjusted for "known and measurable" changes. 16 TAC 25.231(a). See Suburban Utility Corp. v. Public Utility Commission of Texas, 652 S.W.2d 358, 365 (Tex. 1983) (stating that TPUC may make adjustments to test period data to make them representative of future costs). Further, the TPUC may disallow operating costs that are not reasonable and necessary. For example, the TPUC considered whether a utility's entering into a contract with a 100 percent take-or-pay payment for capacity (i.e., a requirement to pay all capacity costs whether or not capacity was taken) was prudent. Determining that the utility did not need any of the capacity and could have purchased electricity from other sources without any capacity charges, the TPUC disallowed the capacity charges. Gulf States Utilities, 841 S.W.2d at 471-72. The TPUC may not allow, as an expense or capital costs, any payment to an affiliate unless the TPUC finds, inter alia, that the price is not higher than the price charged by the affiliate to another affiliate or to a nonaffiliate for the same item. TUCA 36.058(c)(2).

In addition, rates must be based on the "original cost, less depreciation, of property used by and useful to the utility in providing service." TUCA 36.053(a); see also 16 TAC 25.231(c)(2)(A). Generally, plant is not considered used and useful until it is completed. City of El Paso v. Public Utility Commission of Texas, 839 S.W.2d 895, 911-12 (Tex. App. 1992), rev. in part, 883 S.W.2d 179 (Tex. 1994). Consequently, determinations concerning inclusion of plant in rate base are made after plant construction is completed or terminated. However, there are some exceptions to this approach for setting rate base, e.g., for plant not under construction but held for future use and for construction work in progress. See Cities for Fair Utility Rates, 924 S.W.2d at 937-42 (upholding inclusion in rate base of usable portion of costs of uncompleted plant held for future use, where utility had specific plans to use the plant within ten years and where nonusable portion was excluded from rate base and amortized, in order to provide incentive for utility to avoid higher future plant acquisition costs through advance planning and acquisition). CWIP may be included in rate base, but such inclusion is treated as an "exceptional form of rate relief" that the TPUC may allow "only if the utility demonstrates that inclusion is necessary to the utility's financial integrity." TUCA 36.054(a). Inclusion of CWIP in the rate base cannot be used for a "major project" to the extent the project has been "inefficiently or imprudently planned or managed." TUCA 36.054(b). See Texas Utilities Electric Co. v. Public Utility Commission of Texas, 881 S.W.2d 387, 410-411 (Tex. App. 1994), aff'd in relevant part, 935 S.W.2d 109 (Tex. 1996) (upholding inclusion of CWIP in rate base as necessary "to save [utility's] financial integrity"); and 16 TAC 25.232(c)(2)(D).

With regard to completed plant, the TPUC may consider, in an after-the-fact prudence review proceeding, whether costs associated with the plant were prudent and may exclude plant costs from rate base to the extent imprudence is found. See, e.g., City of El Paso v. Public Utility Commission of Texas, 883 S.W.2d 179, 185-86 (Tex. 1994) (upholding exclusion from rate base of portion of capital investment in nuclear plant due to errors in utility decision-making process in deciding what share of plant to own and whether to maintain that ownership share); and Texas Utilities Electric, 881 S.W.2d at 402-09 (upholding exclusion of portion of capital investment in nuclear plant due to utility imprudence).

With regard to cancelled plant, the TPUC also may consider, in an after-the-fact proceeding, the prudence of plant costs. For example, the TPUC reviewed the cancellation of a nuclear plant and determined the date on which the plant would prudently have been cancelled. The TPUC then allowed a ten-year amortization of the investment in the plant up to that date and disallowed recovery of any subsequent investment. Public Utility Commission of Texas v. Houston Lighting & Power Co., 748 S.W.2d 439,440-42 (Tex. Sup. Ct. 1987) (requiring tax savings from write-off of disallowed investment to be retained by ratepayers).

In setting rates, the TPUC must consider the electric utility's cost of capital, which comprises the actual cost of debt, the actual cost of preferred common stock, and, for common stock, a "fair return on its market value." 16 TAC 25.231(c) (1)(C)(ii)(I). See Central Power and Light Co. v. Public Utility Commission of Texas, 36 S.W.3d 547, 553 (Tex. App. 2000). In establishing a "reasonable return on invested capital" (TUCA 36.52), the TPUC must also consider: "efforts and achievements of the utility in conserving resources" (TUCA 36.052(1)); "quality of the utility's service" (TUCA 36.052(2); "efficiency of the utility's operations" (TUCA 36.052(3)); and "quality of the utility's management" (TUCA 36.052(4)).

Adjustment clauses.

The TPUC can allow rates to include adjustment clauses, but only for certain types of costs. TUCA 36.201 states that, except as provided in TUCA 36.204, the TPUC "may not establish a rate or tariff that authorizes an electric utility to automatically adjust and pass through to the utility's customers a change in the utility's fuel or other costs." Under TUCA 36.204(1), the TPUC may allow "timely recovery" of reasonable purchased power costs. See also TUCA 36.205(b) (stating the TPUC may use "any appropriate method" to adjust purchased power costs already approved by TPUC or FERC); and TUCA 36.206 and 36.207 (allowing, only if necessary for the utility's financial integrity, inclusion of markups for cost of purchasing, financial risk of purchased power obligation, and value added in making power available). Further, TUCA 36.203(a) states that TUCA 36.201 does not prohibit the TPUC "from reviewing and providing for adjustments of a utility's fuel factor" in its rates, which may be done without a hearing.

An electric utility can file a petition to update the charge under the fuel adjustment clause as often as every six months (or in the event of emergency) but must show that the fuel costs and electricity sales on which the proposed fuel charge is based are reasonable estimates. 16 TAC 25.237(a)(2) and (c). The TPUC must issue an order on a fuel-charge petition within 60 days, if no hearing is requested within 30 days of the filing, or 90 days, if a hearing is timely requested. 16 TAC 25.237(e) and (f). Every one to three years, the electric utility must file a petition for reconciliation of fuel expenses and show that the fuel expenses are "reasonable and necessary expenses incurred to provide reliable electric service." 16 TAC 25.236(d)(1)(A). See Texas Utilities Electric, 881 S.W.2d at 411-14 (upholding disallowance of unreasonable fuel costs passed through in fuel adjustment clause).

Retail electric competition: restructuring; and nonbypassable charges for transition and securitization of charges.

In 1999, Texas statute was amended to provide for retail electric competition ("customer choice") starting January 1, 2002 in most of the state. See TUCA 39.001(a) and (b) (legislative findings that electricity production and sale are not a monopoly and that "customer choice" is in the public interest). A later start date for retail electric competition was provided for some areas (TUCA 39.102(c); and TUCA 39.401 and 39.402), and the TPUC was authorized to delay the start date for a power region (i.e., NERC region) "unable to offer fair competition and reliable service to all retail customer classes on January 1, 2002" (TUCA 39.103). As a result of these provisions and the TPUC's exercise of its authority under TUCA 39.103, some portions of the state, (essentially the non-ERCOT portions, e.g., areas served by El Paso Electric, Entergy Gulf States, Inc., Mutual Energy-Southwestern Electric Power Co., and Xcel Energy) continue to be subject to Texas's more traditional regulatory system described above until the commencement of customer choice in those areas. See, e.g., Southwest Power Pool, 2003 WL 23101078 (TPUC May 9, 2003) and 2002 WL 31958980 (TPUC Feb. 1, 2002); and Southeastern Reliability Council, 2001 WL 34061563 (TPUC Dec. 20, 2001). In addition, municipalities and rural electric cooperatives may opt, but are not required, to be covered by retail electric competition.

For areas under retail electric competition, Texas statute exempts companies providing electric generation or retail electric service from the requirements of the more traditional regulatory system by adding exemptions to the definition of "electric utility" for a "retail electric provider" (i.e., a person who sells electricity to retail customers and does not own or operate generation assets (TUCA 31.002(17)) and "a power generation company" (i.e., a person who generates electricity for wholesale sale, does not own transmission or distribution facilities, and does not have a certificated service area (TUCA 31.002(10)). TUCA 31.002(6).

Each electric utility is required to separate its business activities into a power generation company, a retail electric provider, and a transmission and distribution company by

January 1, 2002. This can be done by creating affiliate or nonaffiliate companies or by selling assets to third parties. The TPUC must review each electric utility's plan for business separation. TUCA 39.051. A person "that owns generation facilities may not own transmission or distribution facilities" in Texas, except where necessary to interconnect generation with a transmission or distribution system, a facility not dedicated to public use, or a facility that is not an electric utility. TUCA 39.157(b). A power-generation-company affiliate of a transmission or distribution utility may own generation facilities. Id.; see, e.g., Texas-New Mexico Power Co., 2001 WL 1946229 (TPUC Nov. 9, 2001) (approving separation plan creating separate power generation company, transmission and distribution company, and retail electric provider as subsidiaries of existing holding company); TXU Electric Co., 2001 WL 1946230 (TPUC Nov. 9, 2001) (approving plan creating separate transmission and distribution company and company with unregulated businesses as subsidiaries of intermediate holding company); West Texas Utilities Co., 2001 WL 1898427 at 21 (Oct. 25, 2001), aff'd, City of Abiline v. Public Utility Commission of Texas, 2003 WL 549297 (Tex. App. Feb. 27, 2003) (approving plan creating legally separate power generation company, transmission and distribution company, and retail electric provider); and Reliant Energy, Inc., 2001 WL 1448538 (May 29, 2001) (approving division of utility into two separate corporations, one owning transmission and distribution company and power generation company and other owning retail electric provider with option to buy power generation company). Underpinning Texas' decision to restructure the electric industry is the state legislature's finding that "regulation was no longer warranted, except for regulation of transmission and distribution services and regulation of the recovery of stranded costs." City of Corpus Christi v. Public Utility Commission of Texas, 51 S.W.3d 231, 237 (Tex. 2001).

There are additional, statutory requirements aimed at promoting competition in retail electricity generation and sales. Each electric utility is required to sell, by auction, entitlement to at least 15 percent of the utility's installed generation capacity in Texas. The requirement to sell the entitlements continues until the earlier of five years after commencement of consumer choice or the date that nonaffiliated retail electric providers supply 40 percent of the amount of electricity consumed by residential and small commercial customers in the affiliated transmission and distribution company's certificated service area before the commencement of customer choice. Only entities not affiliated with the electric utility and authorized to sell electricity in Texas may buy the entitlements. TUCA 39.153.

In addition, a power generation company may not own or control (directly or through an affiliate) more than 20 percent of "installed generation capacity located in, or capable of delivering electricity to," a NERC region. TUCA 39.154(a). Excluded from the generation capacity owned or controlled is capacity made available for auction under TUCA 39.153. Included in the NERC region's installed generation capacity is any "potentially marketable electric generation capacity," e.g., any capacity for self-

generation and any capacity interconnected with a transmission or distribution system. TUCA 39.154(d). An electric utility or power generation company whose share of installed generation capacity exceeds the 20 percent limit must file a market power mitigation plan for meeting the limit. The TPUC must approve, modify, or reject the plan within 180 days but may not require "divestiture." TUCA 39.156(f). The TPUC must monitor companies' shares of installed generation capacity in order to ensure that the percentage limit is not exceeded. TUCA 39.157(c).

Starting January 1, 2002 in most portions of the state, each retail electric customer in the state must have "customer choice" with unregulated retail electric rates, except for customers of rural electric cooperatives and municipal utilities that do not opt for "customer choice." TUCA 39.102(a). An affiliated retail electric provider of an electric utility serving a retail customer on December 31, 2001 may continue to serve that customer until the customer chooses a different provider. TUCA 39.102(b). During the period 2002-2006, an affiliated retail electric provider must offer, to residential and small commercial customers of its affiliated transmission and distribution company, rates (referred to as "price to beat") that are 6 percent less than the rates as of January 1, 1999. TUCA 39.202(a).

Texas statute establishes a mechanism for electric utilities to recover, through nonbypassable charges, stranded costs that result from deregulation of retail electric service. Specifically, an electric utility "is allowed to recover all of its net, verifiable, nonmitigable stranded costs incurred in purchasing power and providing electric generation service." TUCA 39.252(a). See City of Corpus Christi , 51 S.W.3d 231, 241-46 (upholding constitutionality of allowing recovery of stranded costs through transition charges). "Stranded costs" are defined as the "positive excess of the net book value of generation assets over the market value of the assets" and certain "deferred debits" (e.g., generation-related regulatory assets). TUCA 39.251(7). Book value is determined as of the earlier of December 31, 2001 or the date on which the market value of generation assets is established using a market-based methodology (under TUCA 39.262(h)). An electric utility using the stranded cost recovery mechanism must take action to reduce the amount of such costs. TUCA 39.254. An electric utility with no stranded costs must use revenues in excess of costs for capital expenditures to improve or expand transmission or distribution or to improve air quality. TUCA 39.255(a).

By April 1, 2000, each electric utility must submit rates for transmission and distribution service. In particular, the electric utility must develop a nonbypassable delivery charge that is the sum of: a transmission and distribution charge based on a "forecasted 2002 test year" (TUCA 39.201(b)(1)); a "system benefit fund fee" (TUCA 39.201(b)(2)); and an "expected competition transition charge" reflecting stranded costs projected as of December 31, 2001 (TUCA 39.201(b)(3)). The TPUC will determine the period over which stranded costs may be recovered. In order to recover stranded costs, the electric utility may implement a nonbypassable competition transition charge covering up to 100 percent of estimated stranded costs, may implement a transition charge under a

“financing order” of the TPUC that allows the utility to “securitize” up to 75 percent of estimated stranded costs and 100 percent of regulatory assets, or may implement a combination of these approaches. TUCA 39.201(i). Recovery of an electric utility’s stranded costs will come from all existing or future retail customers in the company’s certificated service area as of May 1, 1999. Moreover, if a customer has new (i.e., post 1999) on-site generation greater than 10 MW, available without the use of the electric utility’s transmission or distribution facilities, and from which the customer starts taking electricity that “materially reduces” its purchase of electricity, a competitive transition charge will be paid by the customer based on the output of the on-site generation. TUCA 39.252(b)(2). A “material reduction” in electricity purchases is defined as a reduction of 12.5 percent or more. 16 TAC 25.345(i)(4). There is an exception if a customer’s load was served by a fully operational qualifying facility before September 1, 2001. In that case, the charge will only be imposed in connection with services actually provided by the transmission and distribution utility. TUCA 39.262(k).

After January 10, 2004, the affiliated power generation company, transmission and distribution utility, and retail electric provider must jointly file final stranded costs and reconcile these costs with the estimated stranded costs used to set the competitive transition charge. TUCA 39.262(c). Based on this filing the TPUC will review the stranded cost estimate and make adjustments to reflect the final costs. The companies will not be permitted to over-recover stranded costs. TUCA 39.262(a). To the extent the estimated costs exceed the final costs, the TPUC may reduce the company’s cost recovery to reflect the difference, e.g., by reducing the competition transition charge to the extent that the costs are not included in a securitized transition charge or reducing the transmission and distribution utility’s rates. TUCA 39.201(l) and 39.262(g). To the extent estimated costs are less than the final costs, the TPUC may increase the nonbypassable delivery charge or extend the period over which it is applied, and the company may securitize the remaining costs. TUCA 39.201(l) and 39.262(c) and (g).

As noted above, Texas statute establishes procedures under which an electric utility may securitize its stranded cost recovery by selling transition bonds supported by such recovery. At the request of an electric utility, the TPUC must issue a “financing order” if the TPUC finds that total revenues to be collected under the financing order are less than the revenue requirement recovered over the remaining life of the stranded assets “using conventional financing methods.” TUCA 39.303(a). The financing order must approve a “transition charge” for stranded costs and regulatory assets that is recoverable in the same manner as the “competitive transition charge” (TUCA 39.303(c)) over a period not exceeding 15 years (TUCA 39.303(b)) and that is “nonbypassable” (TUCA 39.306). There are streamlined and expedited judicial appeal procedures applicable to TPUC financial orders: such orders must be appealed within 15 days to a specified Texas district court, and that court’s decision must be appealed within 15 days to the Texas Supreme Court. TUCA 39.303(f).

Texas has issued a number of financing orders. See, e.g., TXU Electric Co., 1999 WL 33592527 (TPUC Dec. 21, 1999), rev. in part, TXU Electric Co. v. Texas Public Utility Commission, 51 S.W.3d 275 (Tex. 2001); Central Power Light Co., 2000 WL 33529579 (TPUC Mar. 27, 2000); and Reliant Energy Inc., 2000 WL 33529581 (TPUC Jun. 1, 2000) (financing orders approving issuance of transition bonds by wholly owned special purpose entity, imposing transition charges for life of bonds on all existing retail customers of utility as of May 1, 1999 and all future retail customers located in certified service area (including certain customers with new on-site generation), and requiring utility, retail electric providers, and transmission and distribution providers to collect transition charges for special purpose entity). Each financing order states that it is "irrevocable," "final," "not subject to rehearing," and "not subject to review or appeal" except under the streamlined and expedited appeal procedures, and some also state that the order is "binding" on "any successor to the Commission." See, e.g., Central Power Light, 2000 WL 33529579 at 13, 22, and 27. See also TXU Electric Co., 2002 WL 32077783 at 4 (Jun. 20, 2002) (approving issuance of transition bonds as part of settlement).

Once the financing order and the authorized transition charge become final, they are thereafter "irrevocable and not subject to reduction, impairment, or adjustment by further action" of the TPUC, except for an annual true-up. TUCA 39.303(d). Under TUCA 39.307, the TPUC must conduct at least annually a true-up proceeding to correct for any over- or under-collection of the transition charge and to ensure recovery of amounts sufficient to provide timely payments of debt service and other required charges in connection with the transition bonds. But see TXU Electric, 2002 WL 32077783 (holding that true-up proceeding is not required for utility that agreed not to recover any non-regulatory asset stranded costs or other costs otherwise subject to annual true-up).

There is also a series of provisions to ensure that the transition charges are dedicated, and used, to service the transition bonds. For example, the rights and interests of the electric utility under the financing order are "only a contract right" until they are transferred or pledged in connection with the issuance of transition bonds. TUCA 39.304(a). At that time, they become "transition property," i.e., "a present property right for purposes of contracts concerning the sale or pledge of property, even though the imposition and collection of transition charges depends on further acts of the utility or others." TUCA 39.304(b). All revenues from transition charges constitute "proceeds only of the transition property." TUCA 39.304(c). Further, the interest in transition property and the revenues from such property are "not subject to setoff, counterclaim, surcharge, or defense by the electric utility or any other person or in connection with the bankruptcy of the electric utility or any other entity." TUCA 39.305. Moreover, an agreement transferring transition property and stating that the transfer is "a sale or other absolute transfer" means that the transaction is "a true sale" and "not a secured transaction and that title, legal and equitable, has passed to the entity to which the transition property is transferred." TUCA 39.308. In addition, "a valid and enforceable lien and security

interest in transition property" is created only by a financing order and a security agreement in connection with the issuance of transition bonds. TUCA 39.309(b). The lien and security interest attaches upon receipt of value for the bonds, is "continuously perfected" upon the filing of a notice with the Texas Secretary of State, has priority in the order of filing, and takes "precedence over any subsequent judicial or other lien creditor." Id. Finally, Texas pledges not to "take or permit any action that would impair the value of transition property" or to reduce, alter, or impair the transition charge (except for true-up under TUCA 39.307) until the transition bonds are paid in full. TUCA 39.310.

Texas statute provides for an additional nonbypassable charge to retail customers for cost associated with nuclear decommissioning. Those costs "continue to be subject to cost of service rate regulation." TUCA 39.205. A nonbypassable charge is also authorized for the system benefit fund, which may be used only for low-income electric customer assistance, customer education, or school funding losses due to electric restructuring. TUCA 39.903(e). Texas statute does not appear to currently authorize nonbypassable wires charges for any other types of cost.

Retail electric competition: provider of last resort.

The TPUC must designate retail electric providers in customer choice areas as "providers of last resort." TUCA 39.106(a). The provider of last resort must offer, to any requesting customers in its designated area, a "standard retail service package" at a fixed, nondiscountable rate approved by the TPUC. TUCA 39.106(b) and (c). The TPUC must establish procedures and criteria for designating providers of last resort. TUCA 39.106(e). If no retail electric provider applies to be the provider of last resort for a given area on reasonable terms and conditions, the TPUC may require a retail electric provider to take on that function. TUCA 39.106(f). See, e.g., Residential and Small Nonresidential Customers, 2001 WL 34063712 (TPUC Dec. 7, 2001) (approving appointment of providers of last resort, in lieu of failed bidding process, and providing for review and adjustment of provider-of-last-resort rates to ensure there is neither windfall nor net financial loss). Under recently amended regulations, the TPUC will designate providers of last resort through competitive bidding. The TPUC will solicit bids for two-year terms. However, if no eligible bids are received, then the TPUC will select the provider of last resort by lottery. 16 TAC 25.43(g)(2); see Provider of Last Resort Service, 220 PUR4th 1 at 12, 2002 WL 31045264 (Aug. 23, 2002) (explaining that provider-of-last-resort service is a "transitory service that serves as a bridge to alternative offerings in the marketplace" and that providers of last resort should be competitively selected with provider-of-last-resort rates reflecting the costs and risk of the service and not subsidized by users of other services).

As noted above, a provider of last resort must offer a standard retail electric service package with a rate approved by the TPUC. See Residential and Small Nonresidential, 2001 WL 1834071 at 5 (TPUC Aug. 13, 2001) (setting criteria for appointing provider of last resort and holding TPUC has authority to approve reasonable provider-of-last-resort

rate even if no rate is included in proposed standard package). The standard package must include "basic firm service" (16 TAC 25.43(d)(3)), i.e., service that is "not subject to interruption for economic reasons" (16 TAC 25.43(c)(1)). If a customer of another retail electric provider does not receive service by such provider, then the provider of last resort must offer the customer the standard retail electric service package "with no interruption in service to any customer." TUCA 39.106(g). The provider of last resort is responsible for obtaining the resources and services "needed to serve" the customers for which it is responsible. 16 TAC 25.43(n)(4). After its term as the provider of last resort ends, the company may continue to provide retail electric service to such customers who do not choose another provider. 16 TAC 25.43(o)(3)(A).

Special provisions for natural-gas-fired electricity generation and renewable-energy electricity generation.

Texas statute expresses a general preference for natural-gas-fired electric generation. TUCA 39.9044(a) states that it is the intent of the Texas legislature that 50 percent of the generating capacity installed after January 1, 2000 use natural gas. The TPUC is required to establish a program to encourage use of natural gas produced in Texas as "the preferential fuel." Id. In response to this mandate, the TPUC established a program under which a natural gas energy credit is granted for each megawatt of new (i.e., post-January 1, 2000) capacity fueled by natural gas and each power generation company, municipal utility, and rural electric cooperative must hold natural gas energy credits in an amount not less than its new non-gas-fired generating capacity (except for renewable energy projects). 16 TAC 25.172(d). Natural gas energy credits may be traded. 16 TAC 25.172(f). The TPUC will activate the program based on a determination that within three years new capacity fueled "primarily" by natural gas "may fall below 55 percent of all new generating capacity." 16 TAC 25.172(e). The TPUC may accelerate or delay the program if such action is "in the public interest." Id.

Texas statute also sets statewide goals for the use of renewal energy for generation of electricity. The TPCU is required to issue regulations to ensure that an additional 2,000 megawatts of renewable-energy electricity generating capacity is installed in Texas by 2009. TUCA 39.904(a); see 16 TAC 25.173(a). Under the TPUC's implementing regulations, the requirement for new renewable-energy generating capacity applies to competitive retailers, and the amount of required new renewable energy resources increases each year. This annual requirement is allocated among the competitive retailers based on, inter alia, their retail sales. 16 TAC 25.173(h). Renewable energy resource credits are awarded for generation from new renewable energy facilities (i.e, those placed in service on or after September 1, 1999) if, inter alia, their above-market costs are not included in utility rates. 16 TAC 25.173(e)(2). These credits have a three-year life and may be traded or transferred. Each year, each competitive retailer must surrender enough credits to equal its share of the requirement for new renewable-energy resources. 16 TAC 25.173(k)(4).

In contrast with the more traditional electric industry regulatory systems in Indiana, Kentucky, and New Mexico but like the competitive system in Ohio, retail electric competition in Texas generally puts the full risk of new electricity generating plant on investors and makes investors' recovery of costs subject to the operation of the electricity market. In general, this approach is inconsistent with the provision of an assured stream of revenues for new IGCC plants under the 3Party Covenant. See Sections 8.3, 9.3, and 9.4.

8.3. Effect on allocation of electricity generation investment risk.

The approach adopted by a state toward utility regulation has a significant effect on the allocation of investment risk of new electricity generating projects. In particular, for the reasons discussed in Section 7.2 above, the approach in states using more traditional utility regulation tends to put more of the construction, operating, and market risk on ratepayers and require ratepayers to bear such risk earlier, as compared to more competitive approaches to retail electric generation and sale.

As discussed in Section 8.11 above, Indiana has adopted a series of special provisions that modify traditional ratemaking in order to provide for additional sharing of the risk of new electricity generating plant (i.e., a "facility for the generation of electricity" (IC 8-1-8.5-2 through 8-1-8.5-6.5)), "clean coal technology" (IC 8-1-8.7-3 through 8-1-8.7-9), "clean coal and energy projects" (IC 8-1-8.8-11), and "new energy generating facilities" (IC 8-1-8.8-12)) between investors and ratepayers. Under these provisions, the IURC: reviews and certifies proposed new electricity generating plant and clean coal technology; allows for recovery of return on capital for IURC-approved construction work in progress prior to completion of the new plant; provides an assured revenue stream for recovery of IURC-approved capital investment and associated return on capital if the plant is not completed; and provides an assured revenue stream for ongoing recovery of all of the IURC-approved capital investment, return on capital, and operating costs if the plant is completed and operational. Recovery of costs can be through an adjustment clause.

As discussed in Section 8.12 above, Kentucky also has provisions for sharing the risk of new electricity generating plant between investors and ratepayers. However, the Kentucky provisions seem to cover a smaller portion of a new plant, and establish less elaborate procedures providing more rapid but less certain cost recovery, than the Indiana provisions. Kentucky provides for ongoing recovery through an adjustment clause of costs of "complying" with environmental requirements (KRSA 278.183) (e.g., capital investment in, and associated return on capital for, emission controls), as well as costs of fuel and purchased power. Recovery of return on capital can commence during construction.

As discussed in Section 8.13 above, in contrast with Indiana and Kentucky, New Mexico does not have any special statutory provisions aimed at providing a sharing of risk of new

electricity generating plant between investors and ratepayers. However, some current policies of the NMPRC affect the imposition of risk.

In particular, the NMPRC allows inclusion of construction work in progress in the rate base for new electricity generating plant, which puts some risk on ratepayers, but the inclusion of CWIP is treated as extraordinary rate relief. CWIP is included in the rate base (and return on capital is reflected in rates) only to the extent a utility demonstrates: the reasonableness of the project; use of the least cost method for financing the project; and extensive financial hardship and inability to finance without inclusion of CWIP in the rate base. This apparently means that the NMPRC will consider the prudence of ongoing construction and financing in the context of considering the CWIP issue, as well as later in the context of setting rates once the plant is completed and operating.

Another NMPRC policy affecting the sharing of the risk of new electricity generating plant is the NMPRC's approach concerning excess capacity. The NMPRC does not strictly apply a "used and useful" criterion in determining what plant to include in a utility's rate base for purposes of setting rates. Instead, the NMPRC considers both the "used and useful" criterion and the financial health of the utility and determines what is a "fair" result, which generally involves a sharing of risks and thus costs between ratepayers and investors. However, this approach has been applied to electricity generating plants that were operating, not to cancelled plants.

It is not clear whether, or to what extent, NMPRC policy would allow for sharing the costs of cancelled plant between ratepayers and investors and whether construction work in progress allowed in the rate base for cancelled plant would have to be credited back to ratepayers. The NMPRC has stated that, when it finds that utility plant is used and useful and determines what portion of the capital investment is included in rate base, the NMPRC retains the right in the future to find that the plant is no longer used and useful and therefore to disallow some of the capital investment that is currently allowed in rate base. This approach to disallowance of costs of <u>completed, operating</u> plant raises a significant question whether the NMPRC will allow ratepayers to bear some, or any, risk and thus costs of <u>cancelled</u> plant.

Finally, in contrast with Indiana and Kentucky, New Mexico has a statutory provision interpreted as prohibiting the use of adjustment clauses to recover the full panoply of a utility's plant costs (i.e., capital investment, return on capital, and operating costs), as distinguished from an adjustment clause covering only fuel and purchased power costs. This provision does not seem to prevent adjustment-clause recovery of non-fuel plant costs if a utility purchases electricity from a plant owned by a third party. In that case, all of the third party's plant costs apparently may be characterized as purchased power costs for the utility and recovered by the utility through an adjustment clause. However, reflecting past problems with the use of adjustment clauses, NMPRC regulations limit the use of adjustment clauses for fuel and purchased power costs to cases where such costs fluctuate significantly. Despite the NMPRC's authority to approve fuel and purchased power adjustment clauses, the NMPRC has, for at least one utility, required

discontinuation of such adjustment clauses on the grounds that such costs were no longer escalating rapidly and incentives for cost minimization were being reduced. The inability to use an adjustment clause to recover some or all plant costs generally puts more of the risk of recovering such costs on investors.

In Ohio and Texas, one result of utility deregulation legislation is generally to allocate the risk of electricity generating plant to investors, rather than to ratepayers, for companies subject to retail competition. Costs of electricity generating plant are generally to be recovered through rates determined by the electricity market, rather than through cost-based rates determined and imposed by the state PUC. As a result, the risk of cancelled or poorly operating plant, increased plant costs, reduced electricity demand, and declining market electricity prices is generally borne by investors.

However, as discussed in Section 8.2 above, in Ohio and Texas, certain types of plant costs can be recovered through nonbypassable charges set by the state PUC based on costs and paid by all retail customers based generally on their use of the distribution system. In particular, with regard to existing electricity generating plants (i.e., plants as of 2000 in Ohio and as of 2001 in Texas), the portion of capital investment, return on capital, and operating costs that was incurred and deferred for later recovery under the more traditional regulatory system in place before deregulation, but is unlikely to be recovered through market electricity prices, is passed through in nonbypassable wires charges. Depending on the amounts included in the charges, the use of nonbypassable charges can put a portion of the market risk of such existing electricity generating plant on ratepayers.

It should be noted that, if nonbypassable charges can also be used to recover costs of electricity generating plant (whether existing or new) used for provider-of-last-resort service, some construction, operating, and market risk of new plant will be put on ratepayers. In Ohio, each distribution utility must make available, with no time limit, provider-of-last-resort service in its service area, and nonbypassable charges are used to recover certain provider-of-last-resort costs. It is unclear whether or to what extent plant costs (or plant costs reflected in purchased power costs under long-term purchase agreements) will be treated as provider-of-last-resort costs in Ohio. In contrast, in Texas, providers of last resort have two-year terms and are determined through a competitive bidding process or, in the absence of bids, a lottery. Since the TPUC prefers competitive designation of providers of last resort with provider-of-last-resort rates that reflect the costs of provider-of-last-resort service and that are not subsidized by other services, it seems questionable that the TPUC will allow recovery of any provider-of-last-resort costs in nonbypassable charges. Moreover, given the limited term for providers of last resort in Texas, there is a significant question whether plant costs (or plant costs reflected in purchased power costs under long-term purchase agreements) will be treated as provider-of-last-resort costs.