Alabama Public Service Commission

Adjustment Clauses

The base rates for Alabama Power, Alabama Gas, and Mobile Gas Service (MGS) are regulated under Rate Stabilization and Equalization frameworks (see the Alternative Regulation section). The tariffs of the major energy utilities include adjustment provisions to allow for recovery of changes in income taxes, and certain general and local taxes.

An Energy Cost Recovery (ECR) mechanism is in place for Alabama Power. The ECR system is established on the basis of estimates of electric sales, fuel-related costs, and purchased power costs, and reflects accumulated over- or under-recovered amounts. Alabama Power may recover specific costs associated with purchases of natural gas for its electric generating facilities, including the cost of financial tools used for hedging market price risk for up to 75% of the budgeted annual amount of natural gas purchases. The company may not engage in natural gas hedging activities that extend beyond a rolling 42-month window. Also, the premiums paid for natural gas financial options may not exceed 5% of the company's natural gas budget for that year.

The Certificated New Plant (Rate CNP) adjustment clause for Alabama Power provides for: the recovery of costs related to the commercial operation of certified generating facilities; the recovery of the costs (excluding fuel) associated with certified purchased power agreements; and, recovery of costs associated with environmental mandates (see below). Cost recovery by Alabama Power under Rate CNP generally involves a Staff and PSC review process and public meetings. Evidentiary hearings are also held in conjunction with the certification of generating facilities and purchased power agreements.

As noted, Alabama Power may recover costs associated with environmental laws, regulations, or other related mandates through Rate CNP. Such costs are generally subject to a Staff and PSC review, but not a full evidentiary hearing. The mechanism provides for recovery of these costs on an annual basis. Recoverable environmental costs include: (1) applicable O&M expenses; (2) depreciation and a return on capital beginning with 2005 investments; and, (3) a true-up of prior period over/under recovered amounts.

Purchased Gas Adjustment (PGA) riders are in place for Alabama Gas and MGS. The PGA riders reflect virtually all gas cost changes and contain a provision for annual true-up rate adjustments to provide for reconciliation of any excess or deficiency in gas cost recovery. Alabama Gas' PGA (called the Gas Supply Adjustment rider) provides for recovery of: the cost of gas delivered from underground storage, including carrying charges on the month-to-month investment required for stored gas; revenues from capacity-release arrangements made by Alabama Gas under Federal Energy Regulatory Commission (FERC) Order 636; any other costs the FERC allows interstate pipelines to recover; and, the cost of energy-risk-management activities.

Also effective for Alabama Gas and MGS is the Competitive Fuel Clause, which allows the companies to immediately adjust prices in order to compete with any alternate fuel or gas supply source, with no loss of earnings margin for the companies. Alabama Gas and MGS also utilize temperature-based weather normalization mechanisms that mitigate the effect on the companies' earnings of variations from normal weather. (Section updated 6/24/10)

Arizona Corporation Commission

Adjustment Clauses

The ACC eliminated Arizona Public Service's (APS') purchased power and fuel adjustment clause (PPFAC) in 1989, but in 2005 established a Power Supply Adjustor (PSA), a complicated mechanism that permits the deferral and recovery of fuel and purchased power costs. The initially established PSA included restrictions as to the amount of costs that could be deferred and recovered; however, in APS' subsequent rate proceeding (decided in June 2007), the ACC improved the effectiveness of the PSA. The Commission eliminated the cap on total fuel cost recovery, replaced the 4-mil lifetime cap on increases in the PSA with a 4-mil annual cap, and eliminated the filing requirement when the deferred balance reaches $100 million. While the ACC maintained the 90%/10% cost sharing component of the PSA (whereby the company absorbs 10% of fuel and purchased power costs that are in excess of the amount reflected in base rates), the ACC did, however, exclude from the sharing mechanism the demand element of long-term purchased power agreements that were established through competitive procurement and renewable energy purchases, as proposed by the company.

Initially, the PSA was structured to compare one year of actual fuel and purchased power costs with the actual revenues recovered through the company's base rates, with the difference to be recovered over the next year through an annually set adjustor. In the 2007 rate decision, the ACC revised the PSA so that the mechanism now recognizes a forward-looking estimate of such costs to set a rate that is subsequently reconciled with actual costs. The new PSA consists of three components: the "forward component" that recovers or refunds differences between expected fuel and purchased power costs and those reflected in base rates; the "historical component," which tracks the differences between actual costs and those recovered through the combination of base rates and the forward component; and, the "transition component," which provides for the recovery or refund of deferred balances stemming from the operation of the old PSA -- the PSA adjustor that took effect on Feb. 1, 2007 ($0.004 per kWh), and that was scheduled to expire on Jan. 31, 2008, will remain in effect as long as necessary after Jan. 31, 2008, for APS to collect an additional $46 million of fuel and purchased power costs that were deferred as a result of the mid-year implementation of the new base fuel rate.

In APS' June 2007 rate decision, the ACC disallowed approximately $14 million of deferred costs associated with the 2005 Palo Verde outage issues, including accrued interest ($8 million after income taxes). The ACC approved recovery of the balance of such deferrals (approximately $34 million, including accrued interest) through a temporary PSA surcharge over the 12 months beginning July 1, 2007. The decision also requires APS and the Staff to develop a set of "nuclear performance standards" for the ACC to consider in a separate proceeding.

Other adjustment mechanisms used by APS are: a system benefits adjustment clause--for recovery of prudent costs associated with system benefits programs (conservation, wind power, etc.) authorized by the ACC; a competition rules compliance cost adjustment mechanism--for recovery of the accumulated balance of prudent costs (including a return) incurred by the utility to comply with the ACC's electric competition rules; and, a transmission cost adjustor (TCA) to flow through FERC-approved transmission rate changes. In fact, in February 2008, the ACC approved a TCA rate increase for APS approximating $30 million, effective March 1. The increase was equal to that requested by the company and approved by the FERC on Sept. 21, 2007, to become effective March 1, 2008, subject to refund, pending the FERC's final decision in APS' transmission rate case. A final decision was issued by the FERC in July 2008.

Effective Jan. 1, 2009, Tucson Electric Power began using a PPFAC, as per the Commission's Nov. 25, 2008 decision in the company's rate case, in which a settlement was submitted by the parties in May 29, 2008 (FN 11/26/08). The PPFAC includes a forward-looking component. A PPFAC is currently in place for UNS Electric.

Purchased gas adjustments are permitted, and such adjustments generally coincide with price revisions initiated by gas suppliers. The difference between the current cost of purchased gas and the cost of gas being recovered in current rates is deferred and recovered or refunded in the future.

In UNS Gas' Nov. 6, 2007 rate decision, the ACC denied the company's request to establish a revenue decoupling mechanism, indicating that it was unsupported by the record. On 2/23/10, the ACC issued a Notice of Inquiry into the use of decoupling as a tool to encourage utilities to promote energy efficiency programs. (Section updated 2/25/10)

Arkansas Public Service Commission

Adjustment Clauses

Electric utilities recover fuel and purchased power costs through an energy cost recovery (ECR) rider. The ECR rider is calculated annually, reflecting the actual cost experience in the previous calendar year, with an adjustment for projected changes. ECR rate changes are implemented automatically; however, a utility's ECR rider calculation is subject to a 15-day review period. The Staff is permitted to audit any utility's ECR rider and can recommend adjustments to the ECR rate filed by the company. Any such adjustments would typically be made in the next year's true-up.

The electric and gas electric utilities have in place rate riders that provide for the recovery of the costs associated with PSC-approved energy efficiency programs. On Oct. 6, 2010, in a proceeding in which the PSC is considering potential "innovative approaches to utility regulation," the utilities jointly proposed that the PSC approve a cost-recovery methodology, whereby the utilities would amend their energy efficiency cost recovery riders, effective April 1, 2011, to reflect the impact of energy efficiency programs on their recovery of fixed costs (FN 10/15/10).

OG&E utilizes an ECR rider, whereby the company recovers its fuel costs and also: flows to ratepayers 100% of Arkansas-jurisdictional proceeds from the sale of excess SO2 emissions allowances; and, refunds to ratepayers a share of the value of "green credits" resulting from the monetized environmental benefits of generation at the company's Centennial Wind Farm equal to the portion of the project dedicated to serving the Arkansas jurisdiction.

In 2007, the PSC authorized EA to implement a slightly modified version of the company's proposed production cost allocation (PCA) rider, which provides for timely recovery of the costs associated with "rough equalization" of electric generation production costs among the Entergy operating companies, as required by the Federal Energy Regulatory Commission (see the Other/Jurisdictional Allocation Issues section). The company's PCA and ECR riders are to remain in effect subject to 18 months advance notice of termination by the Commission. On May 25, 2010, the PSC authorized EA to establish a storm recovery rider to collect from ratepayers the amounts required to service related securitization bonds (see the Securitization section).

On Nov. 24, 2009, the PSC adopted a settlement providing for SWEPCO to implement a modified version of its proposed generation recovery (GR) rider to begin recovering the costs associated with the 500-MW gas-fired J. Lamar Stall plant once commercial operation commences; a 10% equity return and a 5.93% overall return are utilized to calculate GR rider-related rate adjustments.

All of the regulated gas utilities recover gas commodity costs through automatic purchased gas adjustment (PGA) clauses. PGA rates are established twice annually. Compliance audits are conducted for all costs subject to automatic adjustment.

Arkansas Western Gas (AWG), Arkansas Oklahoma Gas, and CenterPoint Energy Resources (CER) utilize decoupling mechanisms, called trial billing determinant rate adjustment (BDA) riders, to mitigate the impact on the companies' revenues of reduced customer gas usage associated with conservation programs. Separate weather normalization clauses are also in place for AWG and CER.

A bare steel and cast iron gas main replacement program is in place for CER, under which the company is authorized to recover the cost of replacing cast iron and bare steel gas mains and associated services through a surcharge mechanism. (Section updated 11/2/10)

California Public Utilities Commission

Adjustment Clauses

The state's electric utilities utilize a balancing account, the Energy Resource Recovery Account (ERRA), that is designed to track and allow recovery of the difference between electric procurement costs included in rates and actual costs incurred under each utility's procurement plan, excluding the costs associated with the Department of Water Resources (DWR)-allocated contracts and certain other items. The PUC must review the revenues and costs associated with each utility's electricity procurement plan at least annually and adjust retail electricity rates or order refunds, as appropriate. In addition, rate changes are to be implemented when aggregate over-collections or under collections exceed 5% of the utility's prior year electricity procurement revenues, excluding amounts collected for the DWR. The ERRA is to continue for the length of a resource commitment or 10 years, whichever is longer.

The state's electric and gas utilities also operate under revenue adjustment (decoupling) mechanisms that modify rates annually to reflect changes, from any cause, in KWH sales and throughput from levels utilized to establish the revenue requirement.

California's three major natural gas distribution utilities, Pacific Gas and Electric (PG&E), Southern California Gas, and San Diego Gas & Electric, are operating under incentive gas cost recovery mechanisms (see the Alternative Regulation section). The PUC conducts Biennial Cost Allocation Proceedings (BCAPs) to allocate non-fuel gas costs between core and non-core customer classes. The BCAPs provide for the amortization of balances in specified balancing and tracking accounts. The costs tracked through the balancing account mechanisms are subject to annual reasonableness reviews, and a true-up is implemented in the year between BCAPs. (Section updated 7/9/10)

Colorado Public Utilities Commission

Adjustment Clauses

Public Service Company of Colorado's (PSCO's) fuel and purchased energy costs are recovered through an incentive based electric commodity adjustment (ECA) that compares actual fuel and purchased power expenses to a benchmark formula. The ECA also contains certain earnings sharing provisions related to energy trading (see the Alternative Regulation section).

Black Hills Colorado Electric Utility is subject to an ECA under which all fuel and purchased energy cost differences from the company's base energy cost rate are fully recovered from, or credited to, customers.

Since 2004, PSCO has utilized a purchased capacity cost adjustment (PCCA) that allows for recovery of purchased capacity payments to certain power suppliers for specific purchased power agreements not included in base rates or other recovery mechanisms.

Utilities are permitted to recover demand-side management costs and incentives earned on such investments through a separate demand-side management cost adjustment clause (DSMCA).

PSCO utilizes a steam cost adjustment clause (SCA) for steam service under which the company recovers the difference between its actual cost of fuel and the costs recovered in base rates. The SCA is revised at least annually.

Since 2003, PSCO had been recovering the costs associated with a voluntary reduction in air emissions from three of its Denver/Boulder metro area power plants through an Air Quality Improvement (AQI) Rider. On Dec. 3, 2009, in the context of a general rate case, the company's AQI rider was rolled into base rates and eliminated. PSCO has a renewable energy service adjustment in place that is designed to recover costs associated with complying with the state's renewable portfolio standards. Additionally, the company has a wind energy service adjustment for recovery of certain costs associated with the provision of wind energy resources from those customers subscribed as WindSource renewable energy customers.

PSCO is permitted to recover, through a transmission cost adjustment clause (TCA) implemented in January 2008, prudent costs incurred in planning, developing, and completing construction or expansion of transmission facilities for which the PUC has granted a certificate of public convenience and necessity. Through the TCA, utilities may earn a cash return on construction work in progress for investments in grid reliability or new or upgraded transmission facilities. The TCA is to be subject to annual changes.

PSCO utilizes a semi-automatic gas cost adjustment (GCA) mechanism that is adjusted quarterly and permits recovery of the company's actual costs of purchased gas. The GCA is applied to all gas rate schedules, including gas transportation service.

In July 2007, the PUC approved a residential revenue decoupling mechanism, under which PSCO is to absorb the lost revenue associated with the first 1.3% reduction in gas sales each year. The mechanism is to be in effect on a pilot basis from Oct. 1, 2008 through Sept. 30, 2011. (Section updated 6/14/10)

Connecticut Department of Public Utility

Adjustment Clauses

United Illuminating (UI) and Connecticut Light & Power (CL&P) are permitted to recover their full costs of providing generation service to those customers who do not choose an alternative supplier.

Tracking mechanisms are in place for CL&P and UI that provide for semi-annual adjustments to reflect Federal Energy Regulatory Commission-approved transmission costs. As part of a 2009 rate decision for UI, the DPUC adopted pension and cost-of-debt tracking mechanisms.

Purchased gas costs that differ from the levels reflected in base rates are reflected in purchased gas adjustments (PGAs), which are modified monthly. Over- or under-recoveries are refunded to, or collected from, customers during a subsequent 12 month period. A local gas distribution company may suspend or discontinue its PGA clause if approved by the DPUC.

As part of a July 17, 2009 rate case decision, the DPUC abolished Southern Connecticut Gas' (SCG) weather normalization adjustment (WNA), which had been established in 1993. The state's other gas utilities, Yankee Gas Services and Connecticut Natural Gas (CNG), have never operated under a WNA. From 2002-2004 YGS had an annual infrastructure expansion rate mechanism (IERM) that tracked expenses and revenue associated with YGS' system expansion program.

House Bill (H.B.) 7432 allows the DPUC to implement a mechanism designed to decouple electric and gas distribution revenues from sales volumes. Such decoupling may be accomplished through: a mechanism that adjusts actual distribution revenues to reflect allowed revenues; a sales adjustment clause; or, rate design changes that increase the amount of revenue recovered through fixed distribution charges. The law specifies that the DPUC must consider the impact of decoupling on the gas or electric distribution company's return on equity and make necessary adjustments thereto. In 2007, the DPUC denied UI's request to open a generic proceeding to implement electric and gas decoupling, stating that the legislative intent of the decoupling measure was to adopt mechanisms that were company-specific. As part of a 2009 electric rate decision for UI, the DPUC adopted a decoupling mechanism on a two-year pilot basis (Final Report 3/23/09). The Department is in the process of evaluating the decoupling mechanism to determine whether to end, modify or continue the mechanism beyond its two-year trial period. In recent gas rate cases for SCG and CNG, the DPUC declined to adopt decoupling mechanisms. Instead, the Department implemented certain rate design changes to satisfy the intent of the law. (Section updated 7/13/10)

Delaware Public Service Commission

Adjustment Clauses

In conjunction with the implementation of retail competition, the electric fuel adjustment was largely eliminated. As per a settlement approved by the PSC in conjunction with the merger of Conectiv and Pepco (see the Mergers section), Delmarva Power & Light's (Delmarva's) rates were capped through May 31, 2006, with certain exceptions. Power to meet SOS needs is now procured competitively and reflected in rates accordingly (see the Electric Regulatory Reform/Industry Restructuring and Integrated Resource Planning sections). In addition, Delmarva is permitted to submit annual filings to update prices to reflect changes in FERC-approved transmission charges.

Gas cost adjustment clauses (GCA) are permitted, with changes implemented subject to investigation and hearing. GCA clauses are re-set annually based on estimated annual gas commodity costs. Under- or over-recoveries are trued up annually. Delmarva also has a clause in place that permits timely recovery of gas-related environmental compliance costs.

With regard to revenue decoupling mechanisms, in 2008, the PSC: determined that implementation of surcharge mechanisms to reflect the costs/benefits of energy efficiency programs, including the associated revenue impact of the programs "are not the preferred approach, but that the Commission will not preclude the potential use of surcharges in the future under appropriate conditions"; and, opined that adoption of a "modified" fixed variable rate design would be a viable alternative for addressing the revenue impacts of energy efficiency/conservation measures. Implementation of such mechanisms is to be addressed in the context of general rate cases. (Section updated 11/29/10)

District of Columbia Public Se

Adjustment Clauses

Fuel and purchased gas adjustment clauses are permitted by law. However, with the onset of electric retail competition, Potomac Electric Power (Pepco) divested most of its generation assets. Pepco purchases the power to meet its standard offer service (SOS) requirements via a competitive bidding process, and prices paid by SOS customers reflect the weighted average of the winning bids (see the Electric Regulatory Reform/Industry Restructuring section).

On Sept. 28, 2009, the PSC approved the implementation of a Bill Stabilization Adjustment (BSA) for Pepco that became effective Nov. 1, 2009. In so doing, the PSC lowered Pepco's authorized equity return by 50 basis points (FN 11/13/09). The BSA mechanism (decoupling) is applied monthly in order to mitigate the volatility of revenues and customer bills caused by abnormal weather and customer participation in energy efficiency programs.

Washington Gas' (WG's) purchased gas charge (PGC) reflects a quarterly forecast of annual natural gas costs, with annual reconciliations. Since 2001, WG has had a gas hedging program in place that is designed to reduce winter price volatility. In 2008, the PSC approved a financial hedging program for summer natural gas storage injections. Costs/benefits of these programs flow through the PGC, and the plan is reviewed by the PSC annually. WG is also permitted to recover carrying costs on storage balances and over/undercollected gas costs through surcharges. Per a Dec. 16, 2009 PSC order, hexane injection costs are to be recovered through the PGC for sales customers and through the balancing charge for delivery-only customers. Costs associated with the PSC-mandated replacement and encapsulation of certain couplings are to be recovered through a surcharge on distribution rates beginning in 2011.

In the context of a WG distribution rate case decided in 2007, the PSC approved implementation of a gas administrative charge (GAC) as part of its PGC for recovery of uncollectible expense related to gas commodity charges, rather than recovering those expenses in base rates. Separately, the PSC has approved a mechanism that allows WG to recover increases in pension and OPEB expenses through a surcharge between rate cases.

On Dec. 21, 2009, WG filed (Formal Case No. 1079) for a revenue normalization adjustment (RNA) designed to decouple the company's non-gas revenue from actual volumes delivered, and to mitigate differences in revenues that occur due to: weather that varies significantly from normal; and, changes in customer usage that result from customers' energy conservation programs. On December 17, 2010, the PSC issued an order rejecting the proposal. (Section updated 12/20/10)

Florida Public Service Commission

Adjustment Clauses

The fuel and purchased power cost recovery clause (FPPCRC) provides for recovery of prudently incurred fuel and purchased power costs. Annual fuel factors are established based upon 12-month projections of fuel costs and energy purchases and sales. Hearings are held each November, during which the PSC sets fuel factors for the next calendar year. Subsequent to the November hearings, utilities may seek, or the PSC may require, a mid-term modification to the factors if updated projected costs for the year vary from updated projected revenues by plus or minus 10%. Interest is accrued on both over- and under recovered balances. Included in the FPPCRC is a generating performance incentive factor that provides a financial reward or penalty when a company's base load generating units' availability and heat rate vary from targets approved by the PSC. The reward or penalty is limited to a 25-basis-point ROE spread. The PSC generally requires market-based pricing of coal purchased from an affiliate.

The FPPCRC also reflects gains from economy energy sales. A three-year moving average based on eligible sales is determined, and 100% of the sales up to this benchmark are credited to ratepayers. For sales above the benchmark, 80% of the gains from such sales accrue to ratepayers, with 20% retained by the companies.

A capacity cost recovery clause (CCRC) is also in place. The capacity component of purchase power agreements and post-2001 power plant security costs are flowed through this clause on an annual basis. In addition, utilities may recover all prudently incurred site selection and preconstruction costs, including carrying charges, for nuclear and integrated gasification combined-cycle (IGCC) power plants through the CCRC. A cash return on construction work in progress (CWIP) for nuclear plant construction and uprates and IGCC construction is also recoverable through the CCRC.

Pursuant to statutes, the PSC has established an Energy Conservation Cost Recovery Clause (ECCRC) for the recovery of electric and gas conservation-related expenditures. The ECCRC factors are based on projected costs and subject to true-up, similar to the FPPCR mechanism. Also pursuant to statutes, the Commission has established an Environmental Cost Recovery Clause that enables each utility to recover compliance costs associated with environmental laws or mandates that become effective after the test year utilized in the utility's last rate case (see the Emissions Requirements section). The clause is reviewed annually and permits recovery of environmental operations and maintenance costs, related capital investments, and a return on such capital investments.

As part of a settlement adopted by the PSC in 2005, Florida Power & Light (FP&L) was authorized to implement a generation base rate adjustment (GBRA) to allow the company to recover the capital and operating costs associated with any approved power plant that achieved commercial operation from 2006 through 2009. The GBRA applied to FP&L's investment in: Turkey Point Unit 5, which came on line in 2007; and, West Coast Energy Center Unit 1, which achieved commercial operation in August 2009, and, Unit 2, which came on line in the fourth quarter of 2009. On Jan.

13, 2010, the PSC rejected FP&L's request to renew the GBRA.

Purchased gas adjustment (PGA) clauses are in place for the local distribution companies that offer bundled service. The PGA is designed to recover purchased gas costs, and the costs of reserving and utilizing interstate pipeline capacity for the transportation of gas to customers. These charges are adjusted monthly based on a cap approved annually following a PSC hearing. The cap is based on estimated costs of purchased gas and pipeline capacity, and estimated customer usage for a specific recovery period, with a true-up adjustment to reflect the variance of actual costs and revenues from the projections.

Certain fees and taxes, such as franchise fees and gross receipts taxes, are recovered through a line item on customer bills, with the charge adjusted based on customer usage.

The PSC has authorized the utilities to establish surcharges to recover storm restoration costs that exceed their storm reserve funds (see the Other section).

Legislation enacted in 2008, directed the PSC to analyze revenue decoupling and provide a report and recommendations to the governor and Legislature by Jan. 1, 2009. While the PSC Staff report did not contain specific recommendations regarding revenue decoupling, it did note that many of the benefits of decoupling are achieved through the PSC's authorization of various adjustment clauses that permit timely recovery of certain capital and operating expenses. (Section updated 6/23/10)

Georgia Public Service Commission

Adjustment Clauses

A non-automatic fuel adjustment mechanism, known as the fuel cost recovery clause, is in place for Georgia Power (GP). Hearings are required before increases are implemented. Electric fuel rates are based on estimated sales and fuel costs, and any balance of previously unrecovered/over-recovered fuel costs is considered in setting new rates. The energy portion of purchased power transactions is reflected in the mechanism; the capacity component is recovered through base rates.

On Dec. 30, 2010, the PSC issued an order approving a nuclear construction cost recovery (NCCR) tariff for GP. While the PSC order did not specify the revenue to be collected under the NCCR tariff, GP indicated that the company implemented a $223 million rate increase effective Jan. 1, 2011. The approved NCCR tariff enables GP to earn a cash return on construction work in progress (CWIP) related to Plant Vogtle Units 3 and 4, two 1,100-MW nuclear units that are expected to achieve commercial operation in 2016 and 2017, respectively. Senate Bill 31, enacted in April 2009, authorizes Georgia utilities to earn a cash return on CWIP associated with planned nuclear plants that have been certified by the PSC (FN 1/21/11).

The PSC has authorized GP to implement a natural gas and oil procurement hedging program. The costs of the program, including any net losses, are recovered through the fuel cost recovery clause.

As a result of the restructuring of the natural gas industry in Georgia, Atlanta Gas Light (ATGL) no longer procures gas for its customers and, thus, is no longer subject to the purchased gas adjustment mechanism (PGAM). The much smaller Atmos Energy, which is still regulated under a traditional framework, utilizes a non-automatic PGAM.

ATGL has been authorized to recover clean-up costs related to former manufactured gas plant sites through an environmental response cost recovery rider (ERCRR). Costs that are recoverable under the ERCRR include investigation, testing, remediation, and/or litigation costs or other liabilities. (Section updated 2/7/11)

Hawaii Public Utilities Comm

Adjustment Clauses

Fuel adjustment clauses are in place for electric utilities. The clauses are adjusted monthly for changes in fuel costs and the fuel-cost component of purchased energy, and for variations from the forecasted generation mix. Hawaii Electric Light Company (HELCO) and Maui Electric Company (MECO) recover purchased power capacity costs and the operation and maintenance (O&M) expense component of energy costs through base rates. The PUC may impose a surcharge on utility rates for recovery of capacity costs under purchased power contracts with non-fossil-fuel (e.g., geothermal and biomass) producers. On Dec. 29, 2010, the PUC issued an order in the context of Hawaiian Electric Company's (HECO's) 2009-test-year rate case permitting HECO to recover purchased power capacity costs and the O&M expense component of purchased power energy costs via an adjustment clause that is to be adjusted monthly.

The PUC has approved recovery of certain demand-side management program costs (to the extent that they are not recovered through base rates) through an annual integrated resource planning (IRP) cost-recovery surcharge, subject to review.

HECO, HELCO, and MECO utilize tracking mechanisms for pension and other-than-pension employee benefit (OPEB) costs.

In December 2009, the PUC authorized HECO, HELCO, and MECO to implement a surcharge mechanism to facilitate the recovery of renewable energy infrastructure investments (for more information on renewables, see the Renewable Energy section). Recovery is to be capped at 100% of Commission-approved eligible project costs; recovery of any cost overruns may be examined in subsequent rate proceedings. The surcharge is subject to annual adjustments.

On Aug. 31, 2010, the PUC issued an order permitting HECO, HELCO, and MECO to implement revenue decoupling, cost-of-service recovery, and earnings-sharing mechanisms coincident with the Commission's issuance of an interim or final order in the utilities' pending general rate proceedings (FN 9/3/10). On Dec. 29, 2010, the Commission issued an order in the context of HECO's 2009-test-year rate case (Docket No. 2008-0083) permitting the company to implement the above-noted mechanisms (see the Alternative Regulation section). (Section updated 3/14/11)

Idaho Public Utilities Commission

Adjustment Clauses

Electric power cost adjustment (PCA) mechanisms are utilized by Avista Corporation, Idaho Power (IP), and PacifiCorp. The PUC has the authority to implement semi automatic purchased gas adjustments. Electric and gas utilities may seek PUC approval to issue energy cost recovery (securitization) bonds to moderate the impact of power cost increases on customers (see the Securitization section).

Avista Corporation's PCA enables the company to defer, in a balancing account, 90% of the difference between actual net power costs and the amount included in retail rates. As part of a settlement, effective Feb. 1, 2009, the PUC modified the sharing provision in IP's PCA such that annual rate adjustments reflect 95% of the cost variations associated with water supply for hydro-electric production, wholesale energy prices, and retail load changes. Previously, the company utilized a 90/10 sharing formula.

In September 2009, the PUC adopted an energy cost adjustment mechanism for PacifiCorp, allowing for the recovery of 90% of the difference between actual power costs and those included in rates.

In 2007, the PUC approved, on a pilot basis, IP's request to implement a decoupling mechanism, referred to as a Fixed Cost Adjustment. The mechanism is designed to adjust the company's electric rates to recover fixed costs independent of the volume of energy costs. The pilot program is applicable to residential and small customers only. The pilot program began on Jan. 1, 2007; the first adjustment occurred on June 1, 2008, and subsequent adjustments are to occur on June 1 of each year. On April 29, 2010, the PUC denied IP's request to operate under the decoupling mechanism on a permanent basis. Instead, the Commission ordered IP to continue the program on a pilot basis through 2011 (FN 5/17/10).

The state's electric utilities utilize energy efficiency riders, mechanisms that fund the utilities' investments in energy efficiency, conservation, and demand response programs. (Section updated 8/27/10)

Illinois Commerce Commission

Adjustment Clauses
Historically, the electric utilities were permitted to recover fuel costs and the energy component of purchased power costs through a monthly automatic fuel adjustment clause (FAC). The FAC was essentially discontinued in 1997 in conjunction with electric restructuring. The power to meet the utilities' standard offer service (SOS) obligations is now procured competitively (see the Electric Regulatory Reform/Industry Restructuring section); SOS costs and revenues are subject to an annual true-up mechanism.

In conjunction with the approval of the acquisition of IP by Ameren (see the Merger Activity section), the ICC approved a settlement that permits IP to utilize a hazardous materials adjustment clause (HMAC) rider, largely to address asbestos-related litigation and remediation costs. Upon closing of the merger, Ameren deposited $20 million in an HMAC Cost Fund to address asbestos-related issues. In 2007, and each year thereafter, IP will be permitted to withdraw from the fund 90% of the amount by which its annual prudently incurred asbestos-related costs exceed amounts reflected in base rates, or required to deposit into the fund 90% of the amount by which actual expenditures are less than those reflected in base rates. When the fund balance reaches zero, the HMAC Cost Fund will be terminated and an HMAC rider will be implemented to reflect 90% of the difference between actual asbestos-related costs and those reflected in base rates. Once all asbestos-related issues are addressed, the rider is to be terminated.

Statutes permit utilities to utilize adjustment mechanisms for costs associated with legislatively-mandated investment in energy efficiency programs and renewable resource projects (see the Integrated Resource Planning section).

In a 2008 rate decision, the ICC approved ComEd’s proposed rider for system modernization project costs, which will allow the company to adjust rates between rate cases to reflect incremental costs associated with advanced metering infrastructure projects, on a limited basis. In addition, the Commission approved a rider to facilitate recovery of uncollectibles costs.

State law permits utilities to recover costs associated with advanced metering programs (AMP).

On Feb. 2, 2010, the ICC adopted a settlement, thereby authorizing CIL, CIPS, and IP to implement riders to facilitate recovery of their incremental bad debt expense for their electric and gas operations (FN 2/5/10). Similar riders were also approved on this date for ComEd, Northern Illinois-Gas (NI-Gas), Peoples Gas Light & Coke (PGLC) and North Shore Gas (North Shore).

Local gas distribution companies (LDCs) may recover commodity costs through the purchased gas adjustment (PGA) clause. The PGA is automatically adjusted monthly based on fully-forecasted gas costs for the prospective base period, which is either the prospective month for commodity costs or a number of prospective months representing the months remaining in the reconciliation period for non-commodity costs and demand costs. The PGA provides for interest based on the Commission-established customer deposit rate on the unamortized amounts. The ICC conducts annual investigations to examine the prudence of each LDC's gas procurement practices, with refunds required of any imprudently incurred costs.

Statutes permit the LDCs to elect to discontinue their PGAs, with a representative amount of gas costs to be rolled into base rates, as determined by the ICC. If the representative amount determined by the ICC is "unacceptable," the utility may retain the PGA. The LDCs continue to utilize the PGA.

In the context of rate cases decided in 2008 for PGLC and North Shore, the ICC approved a four-year pilot program for a volume balancing adjustment (VBA) rider to decouple the companies' delivery charge revenues from sales in order to eliminate the impact on margins of variations in weather, customer participation in conservation programs, and certain other factors. In addition, the ICC approved an enhanced energy efficiency adjustment mechanism to allow for recovery, outside of a rate case, of expenses associated with energy efficiency programs.

In a March 2009 rate case decision for NI-Gas, the ICC authorized the company to implement an energy efficiency plan rider similar to that approved for PGLC and North Shore. The ICC rejected NI-Gas' proposed VBA rider, as well as riders for uncollectible expense, the cost of gas used for company operations, and certain infrastructure upgrade programs.

Tracking mechanisms are also in place for the recovery of manufactured gas plant site remediation costs. On Jan. 21, 2010, the ICC authorized PGLC to implement a rider to recover certain costs associated with the accelerated replacement of the company's cast iron main system. (Section updated 6/11/10)

Indiana Utility Regulatory Commission

Adjustment Clauses
Electric fuel (the fuel adjustment clause [FAC]) and purchased gas adjustments (PGA) provisions are permitted. State law also permits recovery of certain other costs through adjustment mechanisms.

FAC proceedings--Electric utilities may adjust rates for changes in fuel and purchased power (energy component only) costs every three months, following hearings, through the fuel adjustment clause (FAC). The FAC is based on estimated costs of fuel and purchased power for a future three-month period, with an additional factor to provide for over- or under recoveries caused by variances between estimated and actual costs in the previous three-month period. No carrying charges accrue on over- or under-recoveries. The adjustment factor may be modified more frequently than every three months under emergency circumstances. By law, the URC may not approve an FAC rate adjustment if it will result in the utility earning a net operating income (NOI) in excess of that authorized.

Duke Energy Indiana (DEI) is authorized to recover 100% of purchased power capacity/demand charges through a summer reliability tracking mechanism that is to remain in place until the company's next base rate proceeding. The fuel component of purchased power is to be recovered through the FAC.

Off-System Sales (OSS)--DEI is permitted to equally share with ratepayers OSS margins that vary from the $14.7 million amount included in the company's revenue requirement. In 2009, the URC authorized Indiana Michigan Power (IMP) to implement an OSS margin tracker, such that all margins above a $37.5 million base level are to be shared equally by ratepayers and shareholders.

Environmental Compliance--In 2006, the URC adopted a settlement that permits Southern Indiana Gas & Electric (SIGECO) to recover the costs associated with certain new environmental compliance projects through a surcharge mechanism similar to that previously utilized by the company. The approved settlement permits: (1) a fixed return of 7.98% on the capital costs associated with SIGECO's "Phase One" projects; (2) recovery of the incremental operating expenses associated with these projects; and, (3) accrual of allowance for funds used during construction (AFUDC) until cost recovery of the completed projects begins. Proceeds from the sale of SO2 and mercury emissions allowances are to be shared on a 90%/10% basis by ratepayers and shareholders.

In 2006, the URC adopted a settlement permitting DEI to recover the costs associated with a new environmental compliance plan through certain riders. The settlement provides for: (1) recovery of the costs made in conjunction with "Phase One" of DEI's environmental compliance plan, including associated financing, construction, operation and maintenance (O&M), and depreciation costs, through these riders, utilizing DEI's weighted average cost of capital as the appropriate return; (2) recovery, through these riders, of emission allowance costs incurred to comply with federal environmental regulations; (3) DEI to accrue post-in-service AFUDC and to defer depreciation and O&M expenses until these costs are reflected in base rates; (4) the use of a 20-year accelerated depreciation period for such projects; and, (5) the use of a negative net salvage factor of 10% for such projects. Environmental cost recovery riders are also in place for Northern Indiana Public Service (NIPSCO), Indianapolis Power & Light (IPALCO), and Indiana Michigan Power (IMP). Through these riders, the utilities are also authorized to recover related O&M and depreciation expenses after the environmental facilities become operational.

In an August 2010 rate decision, the URC: approved NIPSCO's request to recover from ratepayers, through its environmental expense recovery mechanism, the net costs associated with the prospective sale/purchase of emissions allowances (see the Final Report dated Sept. 22, 2010). However, at the request of the parties, the URC has not yet approved the company's compliance tariffs, and these cost recovery provisions have not yet been implemented. The parties are working to address this matter in NIPSCO's new rate case.

Other--A settlement approved by the URC for SIGECO in 2007 provides for: SIGECO to utilize semi-annual Reliability Cost and Revenue Adjustment (RCRA) and Demand-Side-Management Adjustment mechanisms (the RCRA mechanism is to reflect incremental changes in, among other things, the ratepayers' 50% share of wholesale power margins [WPMs] that vary from the $10.5 million level included in base rates, and the actual amount of municipal wholesale margins, emission allowances it uses to support its WPM-related sales, interruptible sales billing credits, and non-fuel purchased power costs); the company's existing NOI test to remain in place (the authorized NOI for purposes of this earnings test is to be $76.4 million, with this NOI to be increased to $79.4 million for the next four years, mid-2007 through mid-2011, only to the extent the company's share of WPMs causes the actual NOI to exceed $76.4 million); the NOI cap to be adjusted to reflect the revenues and expenses associated with future environmental compliance projects; and, the company's previous under-earnings bank balance of $202.8 million to be eliminated.

Transmission--IMP is permitted to utilize a Pennsylvania-New Jersey-Maryland (PJM) Interconnection tracker. SIGECO utilizes a Midwest Independent System Operator (MISO) Cost and Revenue Adjustment mechanism, with changes implemented semi-annually, to reflect incremental variations in certain MISO-related expenses. In an August 2010 rate decision, the URC permitted NIPSCO to utilize a regional transmission organization tracking mechanism to reflect incremental variations in certain MISO-related costs and revenues; however, these cost recovery provisions have not yet been implemented.

Energy Efficiency--In 2009, the URC approved SIGECO's request to implement certain electric demand-side management (DSM) programs, and to recover the related costs and retain a portion of the associated cost savings associated with certain DSM programs through an existing cost recovery mechanism. DEI also utilizes an adjustment mechanism to recover prudent DSM program-related costs. IMP is permitted to utilize a DSM/energy efficiency tracker. Indianapolis Power & Light utilizes an energy efficiency rider that permits the company to retain a portion of the savings associated with certain customer conservation programs.

In 2008, DEI filed for URC approval to implement a mechanism to facilitate recovery of the "lost revenues" associated with the company's investment in certain proposed smart grid technologies, but on Nov. 4, 2009, the URC rejected a settlement that called for DEI to install smart meters in its service territory and to recover the associated costs through a tracking mechanism. The URC cited the settlement's lack of detail regarding the methods that would be used to determine the efficacy of the smart grid program-related investments as the impetus for its decision. The parties subsequently filed additional testimony. This proceeding is pending.

Generation--In 2007, the URC approved a certificate of need for DEI's planned Edwardsport integrated gasification combined-cycle plant, and authorized the company to earn a cash return on construction work in progress associated with the plant and to recover the facility's operating costs once complete, through an adjustment mechanism.

Gas Commodity Costs--The gas utilities recover the difference between actual and estimated gas costs through the gas cost adjustment (GCA) clause. A gas utility may not apply for a change in its GCA more often than every three months. However, NIPSCO, SIGECO, and Indiana Gas (IG) are permitted to apply on a monthly basis for GCA changes. By law, the URC may not approve a GCA rate adjustment if it will result in the utility earning an NOI in excess of that authorized in the utility's last rate case.

NIPSCO's GCA clause includes an incentive provision whereby the company equally shares with ratepayers differences between its actual gas costs and a benchmark price. In addition, NIPSCO is permitted to retain 15% of the revenues resulting from capacity release activities. NIPSCO is permitted to reflect in the GCA clause all gas-commodity-related costs, including unaccounted for gas costs and the gas commodity cost component of bad-debt expense).

In 2007, the URC adopted a settlement that provides for SIGECO to track incremental changes in unaccounted-for gas costs (up to a maximum percentage of 1.2% of gas volumes) and the gas-cost component of bad debts (a fixed bad debt ratio of 0.65%) through its GCA filings (these costs were previously recovered through base rates).

In 2008, the URC adopted a settlement that provides for IG to recover incremental changes in its unaccounted-for gas costs up to a maximum percentage of 0.8% of gas volumes, and the gas-cost component of bad debts at a fixed bad debt ratio of 0.9% through its GCA filings (these costs had been recovered through base rates).

Weather Normalization/Decoupling--SIGECO and IG utilize a normal temperature adjustment (NTA) mechanism to eliminate the impact of weather deviations on gas distribution revenues. SIGECO and IG also utilize energy efficiency riders to recover the costs associated with their natural gas energy efficiency programs. The energy efficiency riders are comprised of: an Energy Efficiency Funding Component, which provides for recovery of the costs to fund these programs; and, a Sales Reconciliation Component (SRC), to provide the companies an opportunity to recoup revenues lost as a result of the conservation programs. The margin differences accumulated through the SRC are deferred without carrying charges for recovery/refund beginning April 1st of each year.

NIPSCO utilizes an energy efficiency rider to recover the costs associated with its gas energy efficiency program. The program: provides for NIPSCO to recover, through its GCA mechanism, certain gas commodity-related costs that were traditionally recovered through the fixed customer charge and volumetric commodity charge; requires NIPSCO to credit the first $1 million of incremental revenue associated with implementation of the company's rate simplification plan (an inclining rate structure for its volumetric rate design) to ratepayers through the energy efficiency rider; and, includes a revenue-sharing mechanism, whereby 50% of any incremental revenues in excess of $6 million associated with the plan are to be credited to ratepayers through the rider.

Gas Infrastructure--SIGECO and IG utilize a pipeline safety adjustment (PSA) mechanism, which is subject to annual review by the URC. The PSA allows the companies to recover incremental non-capital expenses incurred due to requirements of the Federal Pipeline Safety Improvement Act of 2002. IG recovers incremental variations in pipeline safety improvement expenses, up to $4.5 million annually, through its PSA (incremental amounts above the $4.5 million annual cap would be deferred, without carrying charges, for future recovery). (Section updated 4/26/11)

Iowa Utilities Board

Adjustment Clauses

Energy adjustment clauses (EACs) are modified monthly based on forecasted energy costs (fuel and purchased power) for two months. The capacity/demand portions of purchased power are recovered through base rates. Under- and over-recoveries are deferred and are charged/credited to customers in the succeeding months. Revenues and costs associated with sales or purchases of emission allowances may be reflected in the EAC. All demand-side management, energy efficiency, and required renewable resource costs are permitted to be recovered, contemporaneously with the expenditure, through a separate adjustment mechanism. As part of a settlement, MidAmerican Energy's (MidAmerican's) EAC was eliminated in 1997 in conjunction with implementation of an alternative regulation plan, and a "representative" EAC revenue level was rolled into base rates and remains fixed.

On Dec. 15, 2010, the IUB authorized Interstate Power & Light to implement a transmission cost recovery mechanism for a three-year term (FN 12/17/10).

Purchased gas adjustment (PGA) filings permit timely adjustments to reflect changes in gas costs. The IUB implemented sporadic contested reviews of gas local distribution companies' (LDC's) gas commodity procurement and contracting practices in 2000, abandoning the previous policy of reviewing gas procurement practices at least every 12 months. The Board is required to notify an LDC 90 days in advance that it plans to review its gas commodity procurement practices. Additionally, LDCs are required to file detailed three-year commodity procurement plans. (Section updated 1/19/11)

Kansas Corporation Commission

Adjustment Clauses

Kansas statutes permit the use of electric Energy Cost Adjustment (ECA) mechanisms to recover variations in fuel and purchased power costs. The ECA is calculated monthly based on projected fuel and purchased power costs for that month, with any under-/over-recoveries reflected in the subsequent month. Penalties may be imposed if actual costs exceed projections for three consecutive months. Those utilities using an ECA mechanism are required to annually discuss fuel planning and purchasing practices with the Staff; fuel contracts are to be competitively bid whenever possible. Any contracts awarded after a competitive bidding process that has been endorsed by the Staff are accorded a "presumption of reasonableness" by the KCC. Any contract longer than one month that is not competitively bid must receive KCC approval before the effective date. Empire District Electric, Westar Energy (Westar), Kansas Gas & Electric (KG&E) and Kansas City Power & Light (KCP&L) currently utilize ECA mechanisms. Westar and KG&E adjust their ECA mechanisms quarterly.

KCP&L flows to ratepayers off-system sales (OSS) margins through its ECA mechanism and recovers the costs associated with energy efficiency programs through an Energy Efficiency Rider.

Westar and KG&E utilize Environmental Cost Recovery (ECR) and Transmission Delivery Charge (TDC) riders. The ECR rider permits timely recovery of the costs to comply with environmental regulations and the TDC rider provides for the unbundling of Federal Energy Regulatory Commission (FERC)-regulated transmission revenues, with recovery to occur through a separate surcharge. Separately, Westar and KG&E are to flow to ratepayers 100% of prospective OSS margins.

In January 2011, the KCC approved a request by Westar and KG&E to participate in the "Efficiency Kansas" conservation program and to recover the related lost revenues through the companies' energy efficiency cost recovery rider.

Purchased gas adjustment (PGA) clauses are based on estimated costs for a 12 month period, with changes made as required. Over- and under-collections are reflected in the subsequent period's adjustment. The local gas distribution companies (LDCs) are permitted to modify their PGAs to include incentive provisions to separately track gas supply and transport costs, and to recover these costs through separate mechanisms. If an LDC voluntarily modifies its PGA, the LDC is subject to a three-year pilot program, during which, the LDC's gas supply contract costs would be compared to a benchmark price established prior to the pilot's implementation. The LDC would equally share with customers, on a monthly basis, the difference between the LDC's contract costs and the benchmark price. The benchmark price would be linked to pipeline price indices. To date, the LDCs have not filed any such pilot programs.

Weather normalization adjustments (WNAs) are in place for ONEOK and Black Hills/Kansas Gas Utility (KGU). Under the WNA, rate adjustments are implemented at the end of the heating season based on the difference between actual and normal weather as measured by degree days. The company accumulates differences in a deferred account and either implements a surcharge or credit on customer bills for the 12-month period beginning each April 1.

State statutes permit the LDCs to request KCC approval of a gas system reliability surcharge (GSRS) mechanism to recover the costs associated with gas distribution system replacement projects, between base rate proceedings, subject to annual true-up. The utilities are permitted to request KCC approval of such mechanisms if: (1) replacement projects are undertaken to comply with federal or state safety requirements; (2) infrastructure relocation projects are undertaken due to construction or improvement of public roads; (3) the utility has had a general rate proceeding decided within the preceding five years, or is the subject of a pending rate proceeding; and, (4) annualized GSRS revenues do not exceed 10% of the utility's base revenue level, as approved in the utility's most recent rate proceeding. The utilities are prohibited from utilizing GSRS mechanisms for periods exceeding five years; GSRS balances are to be reset to zero, with amounts recovered through the surcharge to be rolled into base rates in the utility's next rate proceeding. In addition, a utility may not request changes in the GSRS rate more often than every 12 months.

In 2006, the KCC adopted a settlement that did not establish a GSRS mechanism for ONEOK, but specified that a 10.2% ROE would be used for purposes of determining the carrying charge that would be included in any future GSRS.

Similarly, in 2007, the KCC adopted a settlement for KGU that did not establish a GSRS mechanism, but specified that for purposes of determining the carrying charge that would be included in a GSRS for the company or in other circumstances in which a carrying charge is utilized, the KCC would utilize the average of the ROEs incorporated in the surcharges approved for the other Kansas-jurisdictional gas utilities. The settlement also provides for the company to recover 100% of the gas cost component of bad debt expense through the company's PGA filings.

In 2008, the KCC adopted a settlement that provides for Atmos Energy to utilize a GSRS mechanism. The applicable ROE is to be the average of the ROEs authorized by the KCC in calculating these surcharges for the other Kansas-jurisdictional LDCs. A July 2010 KCC-approved settlement provides for Atmos to refrain from submitting its next GSRS rate adjustment filing until after its next base rate case; the approved settlement also permits Atmos to utilize pension and other-post-employment-benefit tracking mechanisms. (Section updated 4/8/11)

Kentucky Public Service Commission

Adjustment Clauses

The PSC allows fuel and purchased power (energy only) costs to be recovered through automatic fuel adjustment clauses (FACs). Adjustments are implemented monthly, based on actual costs for the second preceding month (producing a two-month lag), with an under- or over-recovery mechanism included in the clause. Incremental replacement power cost increases resulting from forced outages cannot be recovered through the FAC. Public hearings are held every six months to examine procurement and other practices related to fuel and purchased power cost recovery, and adjustments are made to correct for any costs that the PSC determines are unjustified. Additional proceedings are conducted every two years to evaluate the operation of the clause and to set the level of such charges to be included in base rates.

On Oct. 21, 2010, the Kentucky Supreme Court upheld certain aspects of a 2008 Court of Appeals (COA) ruling that addressed several pre-2005 PSC orders that permitted Duke Energy Kentucky to utilize an accelerated main replacement program (AMRP) rider. The Supreme Court's ruling effectively affirms the PSC's authority to allow the utilities to recover certain costs through riders, regardless of whether or not such treatment has been codified by state statute. Accordingly, all prior PSC orders pertaining to DEK's AMRP rider are considered to be valid. (The company's AMRP rider was terminated in late-2009, following the PSC's approval of a rate case settlement.)

By way of background, in the context of DEK's 2002 base rate proceeding (DEK was then known as Union Light, Heat & Power), the PSC had authorized the company to implement a rider, for an initial three-year period, to facilitate recovery of costs associated with its AMRP. In DEK's 2005 rate proceeding, the PSC permitted the rider to remain in place through March 31, 2011. The Attorney General had opposed the rider in both of these proceedings, and subsequently filed appeals with the Franklin Circuit Court seeking reversal of the PSC's orders authorizing DEK to implement and continue to utilize the AMRP rider.

In 2007, the Circuit Court issued an order reversing and remanding to the PSC several prior Commission orders that allowed DEK to implement and continue to utilize the AMRP rider. The Circuit Court determined that the costs associated with the rider must be considered in the context of a base rate proceeding. In 2008, the COA reversed certain aspects of the Circuit Court's ruling. At that time, the COA stated that the AMRP rider was not unconstitutional, but determined that prior to the enactment of the aforementioned legislation, the Commission had lacked such authority. The COA concluded that although the 2005 legislation did not apply to AMRP riders approved prior to its effective date, the PSC's orders approving subsequent AMRP riders are "valid."

Louisville Gas & Electric (LG&E), Kentucky Utilities (KU), and Kentucky Power (KP) are permitted to recover environmental-related investments through an environment cost recovery (ECR) mechanism. Proceedings are conducted every two years to evaluate the operation of the ECR mechanism and to set the level of such charges to be included in base rates.

DEK utilizes an off-system sales (OSS) sharing mechanism, such that: the first $1 million of OSS margins are to flow to ratepayers, with margins above $1 million to be shared equally by ratepayers and shareholders; 100% of prospective emission allowance sales margins also are to flow to ratepayers through the OSS mechanism; and, 100% of "make-whole revenues" pertaining to the company's participation in the Midwest ISO are to flow to ratepayers through the FAC. KP utilizes an OSS-sharing mechanism, whereby OSS margins that vary from a base level are to be shared by ratepayers and shareholders. (see the Alternative Regulation section).

DEK, LG&E, KU, and KP utilize riders to facilitate recovery of costs associated with electric energy efficiency programs; these riders include provisions that permit recovery of lost revenues related to these programs. DEK and LG&E also utilize these riders for their gas operations.

LG&E, Columbia Gas of Kentucky (CGK), Atmos Energy, and Delta Natural Gas utilize gas cost adjustment clauses (GCAs) that are revised quarterly, and DEK utilizes a GCA that is revised monthly, based upon the forecasted cost of gas for the ensuing quarter, with under- or over-recoveries included in the second succeeding quarter's adjustment factor, or in an annual adjustment factor in the case of CGK. In addition, weather normalization adjustment clauses are in place for LG&E, CGK, Atmos, and Delta. LG&E, CGK, and Atmos have gas cost incentive plans with mechanisms that flow a portion of savings to ratepayers through their GCAs (see the Alternative Regulation section).

In December 2009, the PSC adopted a settlement that provides for DEK to reflect the gas commodity portion of uncollectible expense in its GCA.

In October 2009, the PSC adopted a settlement providing for CGK to implement: an AMRP rider; a demand-side management program cost recovery rider that includes provisions for recovery of lost revenues; and, a gas cost uncollectibles provision in the company's GCA clause to reflect incremental changes in commodity-sale-related bad debt expense.

On May 28, 2010, the PSC adopted a settlement that permits Atmos Energy to utilize a pipeline replacement program (PRP) cost recovery mechanism, and to reflect, in the gas cost recovery mechanism, incremental changes in commodity-sale-related bad-debt expense. Separately, in September 2009, the PSC had authorized Atmos to continue to utilize a slightly modified version of its existing demand-side management (DSM) program cost recovery mechanism. Specifically, Atmos is permitted to recover the costs associated with these programs as well as lost revenues associated with DSM-related usage reductions through this mechanism.

On Oct. 21, 2010, the PSC authorized Delta to implement a PRP cost recovery rider and to reflect incremental variations in commodity-sale-related bad-debt costs in the GCA mechanism. Since 2008, Delta has utilized a customer conservation efficiency program (CEP) cost recovery mechanism (essentially a decoupling mechanism) that reflects CEP cost recovery, a revenue adjustment to account for lost sales, and CEP incentive mechanisms. (Section updated 4/8/11)

Louisiana Public Service Commission

Adjustment Clauses

Fuel and purchased power (energy only) costs are recovered through the fuel adjustment clause (FAC). The demand component of purchased power costs related to "economy" purchases (entered into by a company when the price of the purchased power is below the cost of the company's own generation) may also be recovered through the FAC. Monthly filings are required for implementation of changes in the adjustment factor. The major utilities accrue over- or under-recoveries, with the bulk of the accumulated balances refunded/recovered over subsequent 12-month periods. The PSC may audit a utility's purchased power and fuel acquisition practices, and if the Commission determines that the charges passed through the FAC were unreasonable, refunds may be required. For certain utilities, the PSC requires that revenues related to off-system sales be recognized through the FAC.

On July 21, 2009, the PSC authorized the state's electric utilities to use an environmental adjustment clause (EAC) mechanism to recover from ratepayers the costs associated with the acquisition of emissions credits to comply with federal, state, and local environmental standards. In addition, the utilities are to credit ratepayers through the EAC any revenues associated with the sale or transfer of emission allowances that are derived from regulated utilities.

Purchased gas adjustment (PGA) clauses are permitted. Gas supply costs may not be recovered through an LDC's base rates. For full-service customers, during periods of rising or falling gas prices, LDCs may file, on a monthly basis, for implementation of changes in the gas supply rate. LDCs recover the difference between actual and estimated gas costs over the subsequent 12 months. For certain utilities, the Commission requires that revenues related to off-system sales be recognized through the PGA.

CenterPoint Energy Resources, Louisiana Gas Service, and TransLouisiana Gas utilize weather normalization adjustment mechanisms that are to remain in place until terminated by the PSC. (Section updated 3/29/11)

Maine Public Utilities Commission

Adjustment Clauses

Electric fuel adjustment clauses are no longer utilized due to the implementation of retail choice. The state's electric utilities no longer own generation, and by law are required to provide metering and billing of standard offer service (SOS), with power providers selected through a bidding process conducted by the PUC. The full cost of SOS is recovered from ratepayers.

Semi-annual or monthly cost-of-gas adjustment mechanisms are utilized for Northern Utilities, Bangor Gas and Maine Natural Gas. Northern Utilities also recovers manufactured gas site remediation expenses through an environmental remediation rate adjustment that is set on a semi-annual basis. (Section updated 2/10/11)

Maryland Public Service Commission

Adjustment Clauses

Historically, electric utilities were permitted to recover the fuel and energy portion of purchased power costs through the electric fuel rate (EFR). The EFR was eliminated, coincident with the implementation of competition in the provision of electric supply. The utilities continue to provide electric supply service to customers who do not select an alternative generation supplier, and the power to meet these requirements is obtained via competitive bid (see the Electric Regulatory Reform/Industry Restructuring section).

In 2007, the PSC approved monthly bill stabilization adjustment (BSA) mechanisms for Potomac Electric Power (Pepco) and Delmarva Power & Light (Delmarva) that are designed to mitigate the volatility of customer bills during colder- and-warmer-than-normal weather conditions, and the impact of energy efficiency programs. A BSA mechanism was implemented for Baltimore Gas & Electric (BGE) in 2008.

Local gas distribution companies are authorized to use purchased gas adjustment (PGA) clauses that provide for any over or under-recovery of gas costs for a 12-month period to be credited or charged to customers over the ensuing 12 month period. The PGA includes a gas administrative charge for recovery of uncollectible expense related to gas commodity charges.

Washington Gas' (WG's) PGA has been replaced with a "purchased gas charge," which includes the cost of the natural gas commodity and the cost of transporting the gas to the WG system. WG is also permitted to recover carrying costs on storage gas balances and hexane injection costs through a surcharge. BGE is subject to an incentive program, under which a gas price benchmark is established monthly based on actual spot market transactions. Deviations from the benchmark are shared equally with ratepayers. Columbia Gas of Maryland (CGM) has a similar provision, which is limited to spot gas purchases in certain months. A weather normalization clause is in place for CGM, and WG has a revenue normalization mechanism in place. Also CGM is authorized to recover commodity-sales-related uncollectibles through the PGA. (Section updated 9/29/10)

Massachusetts Dept. of Public Utilities

Adjustment Clauses

Quarterly electric fuel and purchased power adjustments were eliminated in 1998, coincident with the start of retail competition. Restructuring orders adopted for most of the electric utilities allowed the rates for standard offer service (SOS), which was available from 1998 through February 2005, to include an SOS fuel adjustment (SOSFA) to reflect fluctuations in the market price of oil and gas. Market-priced default service was also available during the 1998-through-February 2005 period for those customers who were not eligible for SOS and were not receiving generation service from a competitive supplier. SOS service has not been offered since 2005. Default service was extended beyond 2005, and is now called "basic service." Rates for basic service are market-based; such rates reflected the competitive solicitations for basic service supply undertaken by the distribution utility. The utilities are not at risk for fluctuations in market prices.

The electric utilities are permitted to utilize transmission cost recovery mechanisms, and reconciliation mechanisms are in effect for recovery of low-income discounts rates and administrative costs (e.g., employee costs, bad debt and working capital) incurred in providing basic service.

A solar cost adjustment charge was approved by the DPU in conjunction with the Department's Aug. 12, 2009 approval of Western Massachusetts Electric Company's proposal to install 6 MWs of solar energy generation. On Oct. 12, 2010, the DPU approved a solar cost adjustment charge for ME and NE for the utilities installation of 5 MWs of solar generation (see the Integrated Resource Planning section).

The DPU has adopted energy efficiency reconciliation factors (EERF) for the state's electric utilities. The EERF is a fully-reconciling funding mechanism designed to recover the costs associated with the state's electric energy efficiency investments that are in excess of the level collected from other funding sources including the systems benefits charge, proceeds from the forward capacity market, and proceeds from the Regional Greenhouse Gas Initiative.

Pension and post-retirement benefits other than pensions (PBOP) are in place for Massachusetts Electric (ME), Nantucket Electric (NE), WMECO, NSTAR Electric, NSTAR Gas, Fitchburg Gas and Electric Light (FG&E), New England Gas, Boston Gas/Essex Gas, Colonial Gas, and Columbia Gas of Massachusetts. The mechanisms call for the utilities to file annually for the recovery of pension and PBOP costs not currently reflected in rates. Such costs are to be recovered through the LDAC reconciliation mechanism for gas utilities and a separate rate component for electric utilities.

In 2008, the DPU ordered all electric and gas utilities to implement full revenue decoupling mechanisms (defined as mechanisms that separate a distribution company's revenue from all changes in consumption, regardless of the underlying cause of the changes) as part of each company's next base rate proceeding. In its 2008 order, the DPU concluded that it would not require distribution companies to reconcile actual revenue to a revenue target based solely on the number of customers, and would "consider company-specific ratemaking proposals that account for: (1) the impact of capital spending on a company's required revenue target; and (2) the inflationary pressures with respect to the prices of goods and services used by distribution companies." The DPU expects all companies to have operational decoupling plans in place by year-end 2012. Decoupling reconciliation filings are to be made on an annual basis, with additional filings to be required if the company exceeds a threshold of 10% above or below target revenues. During the transition (2009 through 2012) to the implementation of fully decoupled rates, electric distribution utilities are to be permitted to recover lost base revenues (LBR) resulting from the implementation of their three-year energy efficiency plans (see the Integrated Resource Planning section). Gas distribution companies are currently allowed recovery of energy-efficiency-related LBR through their LDACs.

Since the 2008 DPU directive, full revenue-per-customer decoupling mechanisms were adopted for Columbia Gas of Massachusetts, ME and NE in 2009, for Boston Gas/Essex Gas and Colonial Gas in 2010, for WMECO on Jan. 31, 2011, and for New England Gas on March 31, 2011. These mechanisms include a cap on decoupling adjustments, with any amounts above the cap to be deferred for future recovery, with carrying charges. As part of ME and NE's decoupling mechanism, the DPU adopted a tracking mechanism to reflect incremental capital investment of up to $170 million annually less allowance in base rates for depreciation expense. Amounts over the $170 million cap would be addressed in the company's next rate proceeding.

Cost of gas adjustments (CGAs) are determined semi-annually based on seasonally-differentiated peak and off-peak costs. Over- and under recoveries are credited to, or debited against, a deferred gas cost account, and are reconciled by season. Any balance is ultimately passed along or recovered through the CGA factor, including carrying costs. Since 2001, LDCs have been required to submit an amended gas adjustment whenever the company projects that its deferred gas cost balance will be 5% or more of the total season gas costs.

Local distribution adjustment clauses (LDACs) are also in place, with changes on a semi-annual basis to reflect recovery of reconcilable gas-distribution-related costs that are not included in base rates. Such expenses include demand-side management costs, environmental response costs associated with manufactured gas plants, residential arrearage management programs, low income discounts and Federal Energy Regulatory Commission Order 636 transition costs. LDACs are applicable to all firm customers.

In 2009, the DPU approved a targeted infrastructure recovery factor (TIRF) for Columbia Gas of Massachusetts designed to provide for the recovery of incremental expenditures associated with the replacement of its bare and unprotected coated steel mains. The TIRF includes a cap on annual rate increases of 1% of the company's revenues for the prior calendar year, with Department-approved expenses in excess of the cap to be deferred and eligible for recovery in the following year, also subject to the aforementioned cap. On Nov. 2, 2010, the DPU adopted TIRFs for Boston Gas/Essex Gas and Colonial Gas. On March 31, 2011, a TIRF was adopted for New England Gas. (Section updated 4/13/11)

Michigan Public Service Commission

Adjustment Clauses

The Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) clauses require utilities to annually file projected costs, and a forward-looking PSCR or GCR supply factor is established at the beginning of the 12 month collection period. Annual reconciliation proceedings are required. Carrying charges are accrued on over-collections at the higher of the short-term borrowing rate or the authorized ROE for the utility, with under-recoveries permitted to accrue interest at the short-term borrowing rate. Full recovery of prudently expended amounts is required. For electric utilities, the capacity and energy components of purchased power costs are recoverable through the PSCR clause. In addition, for Detroit Edison (DE), Consumers Energy (CE), and Upper Peninsula Power (UPP) transmission costs flow through the PSCR.

DE is authorized a Choice Incentive Mechanism that incorporates a base level of customer choice sales, a deadband around the base level, and customer/stockholder sharing of non-fuel revenues associated with choice sales levels outside of the deadband range. In 2008, the PSC authorized a similar mechanism for CE, but in a Nov. 2, 2009 rate order, terminated the mechanism effective Nov. 30, 2009 (see the Electric Regulatory Reform/Industry Restructuring section for additional details).

In 2009, the PSC adopted a revenue decoupling mechanism for CE's electric operations and for UPP. The Commission authorized DE a revenue decoupling mechanism in January 2010. The PSC has also adopted revenue decoupling mechanism for CE's gas operations (FN 5/21/10), Michigan Consolidated Gas (MCG) (FN 6/4/10), and Michigan Gas Utilities (MGU) (FN 7/2/10).

Legislation enacted in 2008 permits a gas utility that spends at least 0.5% of its revenue on energy efficiency programs to institute a revenue decoupling mechanism.

Uncollectible expense true-up mechanisms are in place for DE, MCG, and MGU (see the Alternative Regulation section). CE's mechanism was terminated effective Nov. 30, 2010, and UPP's was terminated effective Jan. 1, 2011. (Section updated 2/23/11)

Minnesota Public Utilities Commission

Adjustment Clauses

Automatic fuel and purchased gas adjustment (PGA) clauses are permitted. For most electric utilities, the electric fuel clause is adjusted monthly with a two-month lag. For Northern States Power-Minnesota, the PUC permits a forecasted fuel clause that projects monthly costs and provides for a true-up to actual costs. Electric utilities are permitted to recover through the fuel adjustment clause non-administrative Midwest Independent Transmission System Operator Day 2 costs.

In addition, the major utilities use several rate riders that provide for annual recovery of specific costs until the next general rate case, at which time the costs are rolled into base rates. Riders are in place for the recovery of transmission, conservation, renewable, and emission (including mercury) reduction costs (see the Renewable Energy and Emissions sections).

The PGA provides for monthly rate revisions to reflect changes in the current unit cost of purchased gas compared to the cost last included in rates. PGA factors are calculated for the current month based on estimated purchased gas costs for that month. By September of each year, the utilities are required to submit to the PUC an annual report of the PGA factors used to bill each customer class for the previous year beginning July 1 and ending June 30.

In a January 2010 gas rate case decision for CenterPoint Energy Resources, the PUC adopted a pilot revenue decoupling mechanism to make the company whole for revenue fluctuations due to energy conservation initiatives; the mechanism does not adjust for revenue variances caused by abnormal weather (FN 12/4/09). (Section updated 4/13/11)

Mississippi Public Service Commission

Adjustment Clauses

PSC rules provide for automatic electric fuel adjustment clauses, with the energy component of purchased power recovered through the fuel clause and the capacity component recovered in base rates. Both Mississippi Power (MP) and Entergy Mississippi (EM) use levelized fuel adjustment clauses based upon projected fuel use and costs, with a provision for the reconciliation of over- and under-recoveries. MP's fuel adjustment is set for a 12-month period, while EM's is adjusted quarterly. The PSC must conduct an annual audit of all fuel purchases and interchange contracts and submit an annual report to the Legislature. EM and MP also have separate energy cost management clauses to recover fuel hedging gains, losses, and expenses. EM and MP may recover emissions allowance expenses through their adjustment clauses.

Since 1992, MP has utilized an Environmental Compliance Overview (ECO) plan. The ECO plan establishes procedures to facilitate the PSC's review of the company's environmental compliance strategy and provides for base-rate recovery of costs (including the cost of capital) associated with PSC-approved environmental projects, on an annual basis, outside of a base rate case. Under the ECO plan, any increase in annual revenue requirement is limited to 2% of retail revenues. However, the plan also provides for carryover of any amount over the 2% limit into the next year's revenue requirement.

Since 2005, EM has been recovering the costs of its 480-MW, gas-fired Attala power plant through a temporary rate rider. The rider is to remain in place until the company files for a general rate case. (Section updated 2/7/11)

Missouri Public Service Commission

Adjustment Clauses

State statutes permit the electric utilities to request PSC approval of mechanisms that allow for the recovery of costs related to fuel and purchased power, environmental compliance, and renewable energy. According to the PSC's rules: an application for approval of a fuel adjustment clause (FAC) must be submitted within the context of a general rate case or complaint proceeding; an FAC should provide the utility an opportunity to earn a "fair return on equity;" the Commission may adjust a utility's allowed return in future rate proceedings if it determines that implementation of an FAC would alter the utility's business risk; incentive features may be incorporated into an FAC to improve the efficiency and cost-effectiveness of a utility's fuel and purchased power procurement activities; an FAC is to be subject to true-ups for under- and over-collections, including interest; an FAC may reflect incremental variations in off-system sales (OSS) margins; an FAC may remain in place for a maximum four-year term, unless the PSC were to authorize an extension in the context of a general rate case (the utility must file a rate case within four years after implementation of an FAC); such mechanisms are to be subject to a prudence review every 18 months; and, the PSC is to review the effectiveness of these rules no later than Dec. 31, 2010, and may initiate a proceeding to revise the rules if it deems necessary.

The PSC's rules pertaining to environmental cost recovery mechanisms (ECRMs) are similar to those in place for FACs and specify that: the Commission may consider the magnitude of costs eligible for inclusion in an ECRM and the ability of the utility to manage these costs, when determining which cost components to include in an ECRM; the Commission may designate a portion of the utility's environmental costs to be recovered through an ECRM and a portion to be recovered through base rates; the annual recovery of environmental compliance costs is to be capped at 2.5% of the utility's Missouri gross jurisdictional revenues, less certain taxes; a utility that uses an ECRM must file for at least one, and no more than two, annual adjustments to its ECRM rate; adjustments must be made to a utility's ECRM rates within

60 days from the time of filing, if such adjustments adhere to state statutes; an ECRM may remain in place for a maximum four-year term, unless the PSC authorizes an extension in the context of a general rate case (the utility must file a general rate case within four years after implementation of an ECRM); such mechanisms are to be subject to a prudence review every 18 months and an annual true-up for under- and over-collections, including interest; and, the PSC is to review the efficacy of the ECRM rules by Dec. 31, 2011.

The PSC has issued rules pertaining to Renewable Energy Standards rate adjustment mechanisms (RESRAMs), effective in September 2010. (See the Renewable Energy section for further details on these standards.) Electric utilities may file, in the context of a rate case or in a generic proceeding, for a RESRAM that would allow for rate adjustments, to provide for recovery of prudently incurred costs or a pass-through of benefits received, as a result of compliance with the state's renewable energy standards. The RESRAM is to be capped at a 1% annual rate impact.

In 2008, the PSC authorized Empire District Electric (Empire) to implement an FAC that provides for the company to flow to/recover from ratepayers, on a semi-annual basis, 95% of the fuel and purchased power costs, emissions allowance costs and revenues, and OSS revenues that vary from the levels included in base rates. Separately, the PSC authorized Empire to implement a vegetation management and infrastructure inspection tracking mechanism, whereby costs associated with these activities that vary from a base level are to be deferred for future recovery/refund.

Union Electric (UE) utilizes an FAC, implemented in 2009, that provides for the company to recover from/flow through to ratepayers 95% of incremental variations in both fuel and purchased power costs, and OSS revenues from the levels included in base rates. UE's FAC is adjusted every four months and allows inclusion of the net costs associated with the purchase or sale of SO_2 and NO_x emission allowances. UE also utilizes a vegetation management/infrastructure inspection tracking mechanism.

A comprehensive infrastructure expansion program and related regulatory provisions are in place for Kansas City Power & Light (KCP&L) that prohibit KCP&L from seeking implementation of an FAC before June 1, 2015. However, the company is permitted to request approval of an interim energy charge (IEC) that would provide for limited recovery of fuel and purchased power costs, prior to that date.

KCP&L Greater Missouri Operations' FAC, implemented in 2007, is adjusted semiannually. Costs recovered through the FAC include 95% of "prudently incurred" fuel and purchased power costs, net emissions allowance costs, and OSS revenues that vary from the levels included in base rates.

Local gas distribution companies (LDCs) are authorized to reflect changes in gas costs through a purchased gas adjustment (PGA) clause, with up to four adjustments permitted each year. (The Staff has initiated a rulemaking proceeding that will provide a more uniform method in applying PGA-related rate adjustments.) Differences between actual costs incurred and costs reflected in rates are deferred and recovered from, or credited to, customers over a subsequent 12-month period. The companies are permitted to use financial hedging instruments to mitigate the effects of gas-price volatility, and the PSC has implemented a rule that identifies the types of hedging mechanisms that should be considered. The LDCs may request PSC approval of a mechanism to reflect the impact of changes in customer usage due to variations in weather and/or conservation.

Laclede Gas (LCG) utilizes an infrastructure system replacement surcharge (ISRS) to recover costs associated with certain distribution system replacement projects. LCG shares OSS and capacity release revenues with ratepayers, with the related impacts reflected in the PGA clause (see the Alternative Regulation section). LCG is permitted to track, as a regulatory asset/liability, incremental variations in pension-related costs. Union Electric (UE) also utilizes an ISRS and a tracking mechanism for pension and other post-employment benefits expense. Missouri Gas Energy and Atmos Energy both utilize an ISRS and are permitted to record regulatory assets for costs related to energy efficiency programs. (Section updated 9/15/10)

Montana Public Service Commission

Adjustment Clauses

In accordance with the state's restructuring statutes, NorthWestern Corporation (then Montana Power) sold its generation assets in 1999 and subsequently entered into purchased power contracts with competitive suppliers to serve provider-of-last-resort customers. NorthWestern recovers supply costs through a cost recovery mechanism, adjusted monthly, under which rates are based on estimated loads and electricity costs for the upcoming tracking period. The PSC reviews and adjusts results for differences in the previous year's estimates to reflect actual information. NorthWestern is also permitted to recoup revenues lost as a result of demand-side management programs in the context of its annual default supply cost recovery filings.

MDU Resources utilizes a monthly-adjusted fuel and purchased power cost adjustment mechanism that contains certain incentive provisions (see the Alternative Regulation section). The mechanism is to terminate on Dec. 31, 2011, unless extended by the PSC.

MDU Resources and NorthWestern Corporation are permitted to track changes in the cost of purchased gas and other gas costs through separate tariffs. The companies defer, for later recovery or refund, gas expenses that are in excess of, or less than, the costs recovered through current rate levels. MDU Resources' also utilizes a tracking mechanism to recover the costs associated with conservation programs, as well as to recoup revenues lost as a result of the programs.

On Dec. 9, 2010, the Montana PSC authorized NorthWestern Corporation to implement a decoupling mechanism for its residential and small general service electric customers. The mechanism excludes revenue variations due to weather. The pilot program is to be in effect for a four-year period. (Section updated 3/24/11)

Nebraska Public Service Commission

Adjustment Clauses

Semi-automatic purchased gas adjustment mechanisms are in effect for the state's natural gas utilities.

In 2009, Legislative Bill 658 was enacted, allowing gas utilities to apply for PSC approval to implement an infrastructure system replacement cost recovery (ISRCR) rider. The ISRCR rider is to provide for timely recovery of certain capital investments outside of a general rate case and is to be capped at 10% of a utility's Nebraska-jurisdictional annual base revenue level, as authorized by the PSC in the utility's most recent rate case. In addition, small infrastructure replacement investments that would result in an ISRCR rider charge of less than 0.5% of such a baseline amount, or $1 million, whichever is lower, are to be excluded from recovery through the rider. Utilities that have not filed for a rate case within a 60-month period from the date of an application are to be prohibited from implementing an ISRCR rider. Following PSC approval, an ISRCR rider is to expire upon the earlier of: the implementation of new rates stemming from the conclusion of a general rate case filed subsequent to the PSC's approval of the ISRCR rider; or, 60 months. However, the 60-month timeframe can be extended if the utility is engaged in a rate proceeding. We note that the PSC recently rejected a SourceGas Distribution (SG) proposal to implement a mechanism similar to the ISRCR rider, essentially finding that the proposed mechanism was too dissimilar from the established ISRCR framework.

In August 2009, in the context of a generic docket, the PSC concluded that it has the authority to consider utilities' requests to implement revenue decoupling mechanisms under the condition that the mechanisms would not bring about changes to the utilities' overall revenue requirements. We note that the PSC recently rejected an SG request to implement revenue decoupling (see the Final Report dated 4/6/10). (Section updated 2/17/11)

New Hampshire Public Utilities Commission

Adjustment Clauses

Historically, fuel and purchased power adjustment clauses (FPPACs) were permitted. However, Public Service Company of New Hampshire's (PSNH's) FPPAC was eliminated upon implementation of competition. PSNH now recovers its cost of power through a periodically-adjusted default service rate, which reflects the revenue requirements of its generating assets and the cost of power purchases. It also includes a reconciliation of the difference between the company's costs and revenues for the previous period.

A transmission cost adjustment mechanism (TCAM) is also in place for PSNH. The TCAM, which is designed to provide recovery of all transmission-related costs, is adjusted annually effective each July 1.

Cost of gas (COG) adjustment mechanisms are permitted. The local distribution companies are permitted to adjust their charges for gas costs by up to 25%, without prior PUC approval. For EnergyNorth Natural Gas and Northern Utilities customers, the PUC has approved gas cost hedging and a fixed-price option, whereby customers may lock in a price for the winter period.

In 2007, the PUC opened a proceeding (Docket No. DE 07-064) to investigate rate mechanisms, such as revenue decoupling, that could be instituted to remove obstacles for encouraging investments in electric and gas energy efficiency. The PUC ultimately concluded that such mechanisms should only be implemented on a company-by-company basis in the context of a rate case that would examine company-specific revenues, costs, service territory, customer mix, and rate base investment. As part of its pending rate case, EnergyNorth Natural Gas is seeking a revenue decoupling mechanism and proposes to implement annual rate adjustment mechanisms for recovery of pension/postretirement benefits and commodity-related bad debt costs, and to reflect the impact of inflation (less a productivity offset) for certain operating costs (FN 3/5/10). (Section updated 5/3/10)

New Jersey Board of Public Utilities

Adjustment Clauses

Historically, the electric utilities were permitted to reflect variations in fuel and purchased power costs through the Levelized Energy Adjustment Clause (LEAC); the LEAC was suspended in 1999, with the onset of electric retail competition. The utilities now procure power to meet customer requirements in the wholesale market and are permitted to flow these costs to ratepayers on a dollar-for-dollar basis (see the Electric Regulatory Reform/Industry Restructuring section).

Historically, local gas distribution companies (LDCs) were permitted to use levelized gas adjustment (LGA) clauses that were revised annually based upon projected costs of gas for the forthcoming 12-month period. Full retail access for gas customers was implemented in 1999. Under a revised basic gas supply service (BGSS) pricing plan implemented in 2003, BGSS charges for residential and small commercial customers are adjusted periodically to reflect fluctuations in gas commodity prices. Each year the LDCs file residential/small commercial customer BGSS prices to become effective on October 1 of that year. Large commercial and industrial customers taking BGSS service are subject to monthly price changes. Gas cost recoveries are subject to an annual true-up.

A weather normalization clause (WNC) is in place for Pivotal Utility Holdings (PUH), under which no rate adjustment is made if actual weather is within plus or minus 0.5% of the sum of the cumulative normal calendar month degree days for the heating season. PUH may not implement an increase in the WNC if the increase will result in the company earning a return in excess of that last authorized. PSEG also has a WNC in place that was approved as part of a 2010 rate case decision.

PUH is permitted to recover costs associated with manufactured gas site cleanup through a remediation adjustment mechanism. Such expenses are deferred and recovered over a seven-year period, including carrying costs on the balance.

In 2006, the BPU approved pilot energy conservation programs and revenue decoupling mechanisms that had been proposed by New Jersey Natural Gas (NJNG) and South Jersey Gas (SJG). In place of the then-existing WNC, the companies implemented conservation incentive programs (CIPs) that are designed to remove the impact on earnings and revenue of sales fluctuations due to weather variations and customer participation in the conservation programs that are part of the CIPs. Operation of the mechanism is contingent on the company's achieving certain demand-reduction targets. On Jan. 20, 2010, the BPU approved the extension of the CIPs through 2013.

Atlantic City Electric sought approval of a revenue decoupling mechanism in its most recent rate case, but following the May 12, 2010, adoption of a settlement agreement, the proposed bill stabilization adjustment mechanism is to be considered in a separate proceeding to be initiated in the near future.

In a recently completed rate case for PUH, the BPU deferred to a Phase 2 proceeding consideration of the company's proposal to implement a revenue decoupling mechanism in place of the WNC. PUH subsequently withdrew the request (see the Final Report dated 12/23/09). (Section updated 4/8/11)

New Mexico Public Regulation Commission

Adjustment Clauses

Commission rules provide for automatic fuel adjustment clauses; the fuel and purchased power cost adjustment clause (FPPCAC) for an electric utility is calculated monthly (a variance from monthly reporting may be sought), and includes a balancing account in which there is approximately a two-month collection lag. A utility is required to reapply for continuation of an FPPCAC every two years, at which time a comprehensive review of the clause is undertaken.

On Oct. 16, 2007, the PRC issued a Notice of Inquiry into the utilities' practices with respect to the use of FPPCACs. The Commission is investigating why there are differences in the way the New Mexico utilities file and provide required information with respect to their FPPCACs, and will explore methods that may improve the Commission's practices under state law (FN 1/30/08).

On May 22, 2008, the PRC voted three-to-two to allow Public Service Company of New Mexico (PSNM) to establish an emergency FPPCAC. It is our understanding that the clause contains several conditions, including that the recoverable costs will be subject to a prudence review. We note that PSNM's FPPCAC had been eliminated in 1994, following a stipulation, and we expect PSNM to file a new rate case in the near future that incorporates a permanent FPPCAC.

On March 6, 2009, parties filed a settlement in PSNM's pending electric rate case. An FPPCAC is included in the stipulation. Additionally, the stipulation contains an SO2 rider through which customers would be credited with their share of revenues from allowance sales (FN 3/13/09).

After three years of operating without an adjustment clause, El Paso Electric's FPPCAC was reinstated in 2001. As approved by the PRC, El Paso is permitted to seek approval to adjust the FPPCAC if the company experiences an over- or under-recovery balance of at least $2 million of fuel and purchase power expenses as of December 31 and June 30 of each year.

Southwestern Public Service uses an FPPCAC under which it may petition for a change in the fuel factor if the over/under-recovery balance reaches $5 million. In 2001, Texas-New Mexico Power received approval to continue the FPPCAC and to limit the monthly fluctuations in the adjustment clause to $0.003/kWh.

Purchase Gas Adjustment Clauses (PGAC) are also utilized. Changes in the PGAC are made without hearings if a proposed increase is less than 10% of the previous factor. An annual reconciliation audit is required. Monthly over- and under-recovery of gas costs can be recovered through a monthly balancing adjustment to the PGAC. Continued use of the PGAC must be justified every four years. The cost of gas reflected in the PGAC is based upon market projections and averaged (levelized) over a pre-determined period. PSNM uses hedging instruments to mitigate the impact of spikes in the cost of gas, and the financing cost of hedging contracts are recovered through the PGAC.

On June 29, 2007, in a gas rate decision for Public Service Company of New Mexico (PSNM), the PRC rejected the company's proposed decoupling mechanism, stating that the decoupling proposal was too broad. The Commission concluded that the mechanism would make PSNM whole for past conservation efforts of consumers and was therefore fatally flawed. The PRC stated that it would not consider a decoupling mechanism of this type in any case. (Section updated 3/9/09)

New York Public Service Commission

Adjustment Clauses

Historically, all energy utilities used a semi-automatic electric fuel adjustment clause (FAC), through which variations in fuel and gas charges and purchased power costs were passed along to customers. With electric industry restructuring, however, generation was divested, and most of the electric companies transitioned from the FAC to a market power adjustment clause (MAC) or a commodity adjustment clause (CAC). The MAC/CAC allows the distribution utilities to flow through the costs of power procured to serve customers who have not selected an alternative supplier. Changes in the clause are recognized in each customer bill (i.e., monthly, bi-monthly, etc.). Although the incumbent distributors retain the provider-of-last-resort (POLR) obligation, the operation of these clauses leaves the distributor insulated from any financial effects associated with changes in market prices.

On Aug. 29, 2007, the PSC initiated a proceeding to consider establishing a revenue decoupling mechanism for New York State Electric and Gas' (NYSEG's) electric and gas businesses (Case No. 07-E-0996). On July 23, 2008, in an electric rate decision for Orange and Rockland Utilities, the PSC adopted an agreement that included a revenue decoupling mechanism (RDM) similar to that being considered for NYSEG. In a March 25, 2008 electric rate order for Consolidated Edison of New York (Con Ed), the Commission approved an RDM, but rejected the company-proposed weather normalization provision, considering it to be overly complex. With respect to the RDM, the PSC rejected Con Ed's proposal to reconcile revenues on a per-customer basis, and adopted the total class revenue approach. On Dec. 12, 2007, the PSC authorized National Fuel Gas Distribution to implement a conservation incentive (decoupling) mechanism that will allow the company to implement a surcharge through which it would be able to recover lost margin associated with conservation savings generated during the 2008 test year. Niagara Mohawk Power is requesting a decoupling mechanism in a gas rate initiated on May 23, 2008.

Each of the state's gas LDCs utilizes a gas FAC. The FAC mechanism provides for annual reconciliation of recoverable gas costs compared with those billed. Any excess or deficiency is deferred and the balances recovered or refunded annually during a subsequent 12-month period. Weather normalization clauses (WNCs) are utilized by most of the state's gas LDCs. Under the WNCs, the LDCs recover or refund any firm revenue difference experienced during a warmer- or colder-than-normal heating season. Central Hudson Gas & Electric does not utilize a WNC. (Section updated 10/1/08)

North Carolina Utilities Commission

Adjustment Clauses

Prudent electric fuel and fuel-related costs are recoverable through a fuel adjustment clause (FAC). Each utility has an annual hearing to review fuel costs, with a test period determined by the NCUC for each company. The proceedings provide for a true-up of any over- or under-collections from the previous year, with interest included only for over-collections. The costs of certain re-agents (e.g., limestone) used in reducing or treating emissions, as well as certain purchased power costs, may be recovered through the FAC. The law limits the annual increase in recoverable costs related to purchased power to 2% of a utility's total retail revenues.

The law provides that if a utility with nuclear generation fails to meet or exceed certain industry performance measures, there is a presumption of imprudence. Unless it can successfully rebut the presumption, the utility is required to forego recovery of a portion of the fuel costs incurred during the period under review. There is no reward provision. No electric utility has been penalized under this provision in recent years.

Reasonable and prudent costs incurred by an electric utility for new demand side management (DSM) and energy efficiency (EE) measures implemented after January 1, 2007, are recoverable through an annual rate rider. Recoverable costs include, but are not limited to, all capital costs, including cost of capital and depreciation expenses, administrative costs, implementation costs, incentive payments to program participants, and operating costs. The NCUC allows a utility to capitalize all or a portion of those costs that are intended to produce future benefits. Also, the NCUC may approve utility incentives, including allowances for lost revenue (decoupling), for adopting and implementing the new DSM and EE measures. The NCUC limits the assignment of costs of new DSM and EE measures to customer classes that directly benefit from the programs. The costs of new DSM or EE measures may not be assigned to industrial or large commercial customers that notify the utility that they have implemented or will implement alternative DSM and EE measures and elect not to participate in the utility's new DSM and EE measures.

A purchased gas adjustment (PGA) clause is utilized by natural gas utilities. Under NCUC rules: (1) gas purchasing practices are subject to an annual prudence review; (2) commodity and transportation rates are adjusted through the PGA; (3) a local distribution company may recover expenses for additional interstate pipeline capacity and storage added prior to a general rate case, subject to annual true-up; and, (4) changes in demand and storage costs are to be allocated to all customer classes, including transportation, on a volumetric basis.

Since 2005 Piedmont Natural Gas has utilized a Margin Decoupling Mechanism/Tracker (MDT), formerly known as the Customer Utilization Tracker (CUT), that decouples the recovery of authorized margins from sales levels, thus mitigating the impact of weather and energy conservation programs. Public Service Company of North Carolina was authorized to implement a CUT in 2008. (Section updated 12/8/10)

North Dakota Public Service Commission

Adjustment Clauses

Automatic fuel and purchased power (energy only) adjustments are permitted. Fuel and purchased power cost adjustments are implemented monthly, and there is generally a two-month lag for recovery. The state's electric utilities are allowed to earn a cash return on construction work in progress, through a separate rate adjustment mechanism, for investments in transmission infrastructure and on federally-mandated environmental compliance projects. PSC approval is required prior to implementation of the indicated rate adjustments, and the companies are required to file a schedule for completion of transmission projects. Once the facilities achieve commercial operation, they are reflected in base rates, and the surcharge terminates.

Gas utilities may automatically recover gas cost variations on a monthly basis through a purchased gas adjustment mechanism, subject to a two-month lag. (Section updated 11/2/10)

Oklahoma Corporation Commission

Adjustment Clauses

Fully automatic fuel adjustment clauses (FACs) are prohibited in Oklahoma. However, semi-automatic FACs are in place. The OCC reviews each company FAC at least every 12 months, but the utilities may propose more frequent changes if conditions warrant. Once the utility files for a change in its FAC rate, the Staff has five days within which to respond. If the Staff files objections to the change, a formal investigation is initiated; if the Staff files no objections, the proposed rates become effective. The FAC is then reviewed by the OCC at the end of the calendar-year to true up any under- or over-collections.

OCC rules permit the utilities, upon request and Commission approval, to recover security/safety-related costs through a surcharge/rate rider. In addition, the OCC may approve requests to recover costs associated with Federal Energy Regulatory Commission/Regional Transmission Organization-mandated transmission upgrades and environmental compliance costs through a surcharge/rate rider. We note that both Oklahoma Gas & Electric (OG&E) and Public Service Oklahoma (PSO) participate in the Southwest Power Pool.

OG&E's FAC is adjusted annually, subject to a cap on under- and over-recoveries. Specifically, the annual factor may be adjusted periodically, but not more than quarterly, if cost levels have changed or the under- or over-recovered balance exceeds 5% of the annual Oklahoma-jurisdictional fuel cost. Otherwise, amounts that differ from the levels reflected in each month's actual fuel cost calculations are deferred in a balancing account, and the deferrals are recovered over the subsequent 12-month period with interest. Purchased power and certain cogeneration and capacity payment differentials, and ratepayers' 80% share of off-system sales margins, are reflected in the FAC. OG&E also recovers a portion of the transportation costs associated with gas deliveries to its generating facilities through the FAC. OG&E has a separate rider in place to recover the costs associated with security/safety expenditures; green power initiatives; renewable resource investment; and, cogeneration.

In 2008, the OCC approved a settlement, thereby authorizing OG&E to implement a storm cost recovery rider. The settlement permits OG&E to recover $33.7 million of storm costs through the rider, over a five-year period that began in September 2008. The company accrues an overall return on the unamortized storm cost balance that is based on a 10.75% return on equity. In addition, the rider is to be adjusted annually to reflect any differences between the level of storm costs reflected in base rates ($2.7 million) and the level of such costs actually incurred in that year. Also, OG&E may retain 100% of the annual proceeds from the sale of SO2 emissions allowances up to $3.4 million, with the proceeds in excess of this amount to be applied to reduce the impact of the rider.

OG&E utilizes a rider to recover roughly $220 million of costs associated with the company's system-wide "Smart Grid" program. (OG&E received approval in late-2009 from the U.S. Department of Energy for a $130 million grant that would fund the non-ratepayer-funded portion of the project.) OG&E also utilizes an energy efficiency rider that includes provisions to facilitate recovery of lost revenues associated with conservation programs.

In 2009, the OCC adopted a settlement that permits OG&E to recover the costs associated with the 101-MW "OU Spirit" wind facility through a cost recovery rider. The rider is to remain in place until the earlier of Dec. 31, 2011, or the implementation of new rates in OG&E's next rate proceeding (expected to be filed in 2010/2011); and, the costs associated with the project are to be reflected in the company's base rates in its next rate case. The 8.658% overall return authorized in the company's most recent fully-litigated rate proceeding is to be utilized in the context of this rider. The approved settlement also provides for OG&E to sell OU Spirit-related renewable energy credits (RECs) to the University of Oklahoma, and to flow to ratepayers, through certain riders, 100% of the Oklahoma-jurisdictional proceeds from such sales. (OG&E would share with ratepayers on an 80%/20% basis, respectively, the proceeds associated with RECs sold to entities other than the University of Oklahoma.)

The OCC has authorized OG&E to utilize a rider to recover the revenue requirement associated with the company's Crossroads Wind Farm (up to 227 MW of capacity). This facility is expected to be completed in 2011; the rider is to remain in place until new base rates are implemented (a rate case is expected in 2013). OG&E is to flow through to ratepayers, during the period the rider is in place, 100% of the proceeds associated with the sale of the RECs that accrue from the plant's operation.

OG&E is permitted to recover costs (both capital- and expense-related) associated with the company's "system hardening" and "vegetation management" programs, through a rider. This program is to be completed in June 2012. The rider has been in place since 2009 and is adjusted annually.

PSO's FAC is adjusted annually, subject to a cap on under- and over-recoveries. Specifically, an immediate adjustment is implemented if the under- or over-recovered balance exceeds $50 million. Otherwise, amounts that differ from the levels reflected in base rates are deferred in a balancing account, and the deferrals are recovered over the subsequent 12 months. The FAC also allows for current recovery of line losses above or below the amount recognized in PSO's base rates. Such under or over-recoveries are recovered from, or refunded to, customers during subsequent months.

Purchased gas adjustment clauses are monitored on an ongoing basis by the OCC, with hearings every 12 months. Monthly adjustments are calculated based on the average cost of gas for the prior month. Under or over-recoveries are deferred and recovered from, or refunded to, customers in a subsequent billing period.

CenterPoint Energy Resources utilizes a weather normalization mechanism for its gas operations. (Section updated 4/8/11)

Oregon Public Utility Commission

Adjustment Clauses

Until recently, power cost adjustment mechanism (PCAM) clauses had not been utilized in Oregon. However, in certain instances, the PUC had permitted utilities to defer for future recovery power supply costs that were higher than those included in base rates, subject to certain deadbands and sharing provisions. Portland General Electric (PGE), PacifiCorp, and Idaho Power (IP) are now permitted to annually adjust rates to reflect forecasted power costs. PGE's and IP's mechanisms include a component under which a portion of differences between actual and forecasted power costs are deferred for future recovery or refund.

PGE's current power cost recovery framework includes both an annual update, under which rates change each January 1, to reflect updated net variable power costs (NVPC), and a PCAM that is designed to capture a portion of the difference between the NVPC forecast (i.e., baseline NVPC) established through the annual update and the actual NVPC incurred by PGE for that year. The PCAM is subject to a deadband of $15 million below to $30 million above the ultimately established NVPC, a sharing ratio, and an earnings test. PGE absorbs 100% of the costs/benefits within a PUC-determined deadband around the baseline NVPC, and amounts above or below the deadband are shared 90% with customers and 10% with PGE. A refund would occur only to the extent that the refund would result in PGE's actual ROE for that year being no less than 100 basis points above PGE's last authorized ROE. A surcharge would occur only to the extent that the surcharge would result in PGE's actual ROE for that year being no greater than 100 basis points below PGE's last authorized ROE.

Renewable resources adjustment clauses (RAC) are utilized for the state's electric utilities for the recovery of prudently incurred costs associated with meeting the state's renewable energy standards. The mechanism allows for recovery of renewable resources that are expected to be placed into service in the current year to be recovered from ratepayers without filing a general rate case (see the Renewable Energy section).

An automatic adjustment clause is in effect to flow back the amount of taxes reflected in rates that differ by at least $0.1 million from the amount of taxes actually paid by the utility or the consolidated corporation to federal, state, and local taxing authorities (see the Accounting section).

In January 2009, the PUC adopted an electric revenue decoupling mechanism for PGE to be initially effective Feb. 1, 2009, for a two-year trial period. On Dec. 17, 2010, the PUC extended the mechanism through Dec. 31, 2013. The mechanism is designed to provide for the recovery of reduced revenues resulting from reduced consumption patterns of residential and certain commercial customers' conservation efforts.

On Dec. 17, 2010, the PUC adopted an automatic depreciation-related tariff for PGE that would reflect in rates the incremental revenue requirement effect of a shortened operating life for PGE's Boardman plant. We note that PGE was originally expected to operate the plant through the end of the plant's estimated useful life. The company's remaining undepreciated investment in the plant is being recovered in rates through 2040. As a result of changing environmental regulations, plans are in progress for PGE to cease operating the plant earlier than 2040.

Purchased gas adjustment (PGA) rate changes become effective on November 1 of each year, and an out-of-cycle adjustment is permitted if a company's gas costs change by 10% or more. The PGAs for the state's local distribution companies (LDCs)--Northwest Natural Gas (NWN), Cascade Natural Gas (CNG), and Avista Corporation--contain an incentive mechanism, whereby a percentage of any variance between the companies' cost of gas included in its rates and its actual cost is absorbed or retained by the LDC. Recovery is subject to an annual earnings review (see the Alternative Regulation section).

A decoupling mechanism is in place for NWN that is designed to counteract the impact on revenues of changes in average consumption patterns due to residential and commercial customers' conservation efforts. NWN has a separate weather-adjusted rate mechanism (WARM) in place for residential and commercial customers. Customers are permitted to opt out of WARM (about 10% do not participate), and the program is to be in place through Oct. 31, 2012. The mechanism is to remain in effect through Oct. 31, 2012. CNG had a decoupling mechanism in effect until September 2010, that applied to both conservation-related-demand reduction, and adjusts for deviations from normal weather.

In February 2009, the PUC authorized NWN to implement a new System Integrity Program (SIP) designed to recover costs related to base steel, pipeline integrity, and other pipeline safety programs. Costs are to be tracked annually, with recovery to be sought through the PGA after the first $3.3 million of capital costs are incurred by the company. The recovery of SIP costs are to be subject to an annual soft cap of $12 million, with any extraordinary expenses above the cap to be subject to PUC approval. (Section updated 1/25/11)

Pennsylvania Public Utility Commission

Adjustment Clauses

Historically, electric utilities were permitted to recover fuel and purchased power costs through a semi-automatic adjustment mechanism, the Energy Cost Rate (ECR); however, in accordance with 1997 electric industry restructuring legislation, the ECR was eliminated. The law requires the utilities to offer provider-of-last-resort (POLR) service at capped rates for the duration of their competition transition periods. Therefore, during the transition periods, the utilities are at risk for variations in power costs. Once each company's transition period expires, generation required to meet POLR obligation for that company is to be competitively procured and priced. (For additional detail refer to the Electric Regulatory Reform/Industry Restructuring section.)

PPL Electric Utilities (PPL-E) has a mechanism in place to allow changes in Federal Energy Regulatory Commission-approved PJM Interconnection transmission charges to be automatically reflected in rates, subject to annual true-up. Transmission cost tracking mechanisms have also been approved for Duquesne Light, Metropolitan Edison, and

Pennsylvania Electric.

PPL-E also has a surcharge in place to recover universal service program costs. Legislation enacted in 2008, allows energy efficiency program costs to be recovered through a surcharge. In addition, the PUC has adopted rules allowing the electric distribution utilities to recover the costs associated with legislatively mandated energy conservation programs through an adjustment clause (see the Integrated Resource Planning section).

A non-automatic procedure is in place for recovery of fluctuations in gas costs. Tariff changes must be filed for PUC review six months prior to the proposed effective date. The companies may recover the difference in actual costs versus those projected, if the actual costs were reasonably incurred. Such filings may be made no more often than once every 12 months; however, quarterly updates to reflect unrecovered gas costs from the prior quarter are permitted. While there have been no decoupling mechanisms or weather normalization clauses approved for electric or gas utilities in the state, in certain recent rate cases the PUC has authorized the companies to increase monthly fixed customer charges so that a greater portion of fixed costs are recovered through the fixed-charge component of customer bills. (For additional detail refer to the Rate Structure section.) (Section updated 4/8/11)

Public Service Commission West Virginia

Adjustment Clauses

Electric fuel and/or purchased power costs may be recovered through either a fuel adjustment clause (FAC) or an expanded net energy cost (ENEC) factor. In addition to fuel costs, the ENEC includes the energy portion of purchased power costs, offsets for energy cost recoveries in affiliated and other wholesale sales, the demand portion of purchased power transactions, power pool capacity payments, and offsets for demand credits from affiliated and other wholesale transactions, and demand-related transmission costs and credits. ENEC factors are set annually based on actual data for the prior 12-month period and projected data for the prospective 12-months. Over- or under-recoveries are deferred for reconciliation as part of the next ENEC proceeding, with no carrying charges on the deferred balance. ENEC proceedings are typically completed within four months of filing.

In accordance with a 1999 settlement and PSC order, the ENECs for Appalachian Power (APCO) and Wheeling Power (WP) were suspended from 2000-July 2006. In 2006, the PSC adopted a comprehensive multi-year rate settlement that called for APCO's ENEC to be reinstated effective July 1, 2006.

In 2006, the PSC established a surcharge mechanism for APCO to recover certain transmission expansion and environmental compliance projects. In 2008, the PSC approved a similar mechanism for a 630-MW integrated gas combined-cycle plant proposed by APCO, but the project was tabled after the Virginia State Corporation rejected the plant.

From July 1, 2000 through May 22, 2007, Monongahela Power (MonPower) and Potomac Edison (PotEd) operated without an ENEC, with a fixed level of ENEC charges rolled into base rates. In the context of a 2007 rate case decision, the PSC authorized the companies to reinstate the ENEC.

Major local gas distribution companies file annual purchased gas adjustments (PGAs) based on projected costs, with over- or under-recoveries reflected in rates in subsequent periods.

While there have been no decoupling mechanisms or weather normalization adjustment mechanisms (WNAs) approved for the major electric or gas utilities in the state, the PSC has approved WNAs for certain smaller local gas distribution companies on a pilot basis (the program extends through 2014). In the context of a rate case decided in December 2009, the PSC rejected Hope Gas' request for approval of a WNC, finding that the operational characteristics of Hope (versus the eight smaller companies that are part of the pilot) render a WNA unnecessary for Hope and stated that it "does not believe that Hope must necessarily await the outcome of the pilot program, but a larger gas utility such as Hope is fully capable of absorbing downward swings in revenue in warmer than normal winters. This revenue shortfall is not a permanent revenue shortfall because Hope is allowed to keep the increased revenue generated in colder than normal winters." (Section updated 4/8/11)

Public Service Commission of Wisconsin

Adjustment Clauses
Under PSC electric fuel rules, each utility forecasts monthly and annual fuel and purchased power costs on a prospective basis. If a company's actual fuel and purchased power costs are outside a monthly or cumulative monthly variance range around the forecasts, and the utility can demonstrate that these costs will likely be outside the annual range, the PSC may conduct a hearing to establish new rates. Currently, the annual variance range is plus or minus 2%. Assembly Bill (AB) 600, which was enacted on May 18, 2010, modified the electric fuel cost recovery framework to permit an electric utility to defer any fuel costs that are outside of its annual, symmetrical variance range for subsequent recovery or refund. However, the utility is prohibited from recovering deferrals if the company is found to be earning in excess of its authorized equity return. Previously, deferral was permitted only with prior PSC authorization and under very limited circumstances.

The PSC requires all local natural gas distribution companies (LDCs) to compare actual gas costs to the gas-cost revenue recovered through the gas cost recovery mechanism (GCRM). Large LDCs must choose either an incentive (see the Alternative Regulation section) or a modified "one-for-one" GCRM. Under a modified one-for-one GCRM, if gas costs are less than the benchmark, the utility's procurement is assumed to be prudent and the lower costs are passed on to customers. If gas costs are greater than the benchmark, the PSC may initiate a prudence investigation. Wisconsin Public Service, Wisconsin Power & Light, and Northern States Power Wisconsin are operating under modified one-for-one GCRMs. Wisconsin Gas, Wisconsin Electric Power, and Madison Gas and Electric are operating under incentive gas cost recovery mechanisms.

In 2009, Wisconsin Public Service implemented four-year, full, pilot revenue decoupling mechanisms for residential and small commercial electric and gas customers. Annual rate changes under the mechanism are limited to plus or minus $14 million for electric and plus or minus $8 million for gas operations. (Section updated 4/27/11)

Public Service Commission of Utah

Adjustment Clauses
Legislation enacted in 2009 grants the PSC the authority to allow electric and gas utilities to implement balancing accounts to recover power costs and purchased gas costs. We note that the PSC has authorized such mechanisms in the past, despite the lack of specific statutory authority to do so. Although no power cost adjustment mechanism is currently in place, the PSC has permitted PacifiCorp to implement temporary rate increases to recover purchased power costs not included in base rates.

Questar Gas files semi-annually to adjust its base purchased gas cost rate for actual or projected changes. Under- or over-recoveries are generally amortized through sales customers' rates over a 12-month period. Questar Gas flows 90% of its capacity release revenue to customers via the semi-annual gas-cost pass-through proceeding. After several years of debate surrounding the recovery of carbon dioxide processing costs, Questar Gas, following a settlement adopted by the PSC in 2006, was permitted to recover 90% of the non-fuel processing costs and 10% of the fuel costs up to 360 Mdth per year. The company is to share half of third-party processing revenue with customers after the first $0.4 million.

A pilot infrastructure replacement adjustment (IRA) mechanism was established by the PSC for Questar Gas in an April 8, 2010 PSC rate decision (see the Final Report dated 7/2/10). Under the three-year pilot IRA mechanism, the company is permitted to track and recover between rate cases, the costs associated with the replacement of high-pressure natural gas feeder lines. The mechanism is to be adjusted at least annually, and has an annual budget cap of $55 million.

A weather normalization adjustment (WNA) is in place for Questar Gas. However, customers may elect not to participate in the WNA.

Since 2006, Questar Gas has operated under a conservation-enabling tariff (CET), which decouples non-gas revenues from the volume of gas used by customers. Under the CET, a margin-per-customer target is specified for each month, with differences to be deferred and recovered from, or refunded to, customers via periodic rate adjustments. We note that 2009 legislation codified the PSC's authority to implement rate designs that include decoupling mechanisms. (Section updated 3/22/11)

Public Utilities Commission of Ohio

Adjustment Clauses

As a result of the enactment of electric industry restructuring legislation, effective Jan. 1, 2001, electric utilities no longer use the electric fuel component that had provided for fuel rate adjustments outside of base rate cases. Through year-end 2005, the electric utilities operated under hard rate caps; therefore, the investor-owned utilities were at risk for variations in fuel prices and purchased power costs. However, the utilities now operate under rate stabilization plans (RSPs) (see the Electric Regulatory Reform/Industry Restructuring section) that allow for rate recognition of at least a portion of the increases in fuel prices, purchased power costs, and emissions expenditures.

Gas utilities are permitted to use a gas cost recovery clause (GCR), which provides for quarterly adjustments, with an annual review and hearing. The GCR includes a mechanism to revise charges in a subsequent three-month period for any under- or over-recoveries related to the collection of an earlier period. With PUC approval, a local distribution company can make monthly changes to its GCR, and many companies are doing so. The PUC has established a framework for determining whether gas companies' procurement practices minimize overall costs to utility customers while assuring adequate supplies of gas.

In May 2006, the PUC approved a stipulation, thereby eliminating East Ohio Gas' (EOG's) GCR charge, and allowing the company to charge commodity prices that are determined through a descending-clock auction. The PUC indicated that the first phase of the plan will serve as a pilot program to test the ability of the new pricing methodology to enhance competition and reduce long-term natural gas rates. Typically, EOG obtained its gas through individually negotiated bilateral contracts. Under the new plan, EOG conducts an auction that allows suppliers to compete to supply portions of EOG's requirements. The company's customers have a choice of receiving natural gas directly from a competitive supplier or from EOG's retail sales service. EOG remains the provider of last resort during phase one.

Since 2002, Duke Energy Ohio has used a Rider Accelerated Main Replacement Program (AMRP), through which it recovers the costs associated with its extensive gas delivery infrastructure improvement program. The AMRP is facilitating the reduction of bare steel and cast iron mains in the distribution system.

In September 2006, the PUC established a conservation program and a sales reconciliation rider for Vectren Energy Delivery of Ohio (Vectren). Under the conservation plan, Vectren is to implement a portfolio of programs for a minimum term of two years for low-income customers only. The company is to fully fund the $2.67 million budget for the program adopted by the PUC. The Commission stated that the sales rider should allow the company an opportunity to recover the base rate revenue requirement established for the residential and general service customer classes established in the company's last rate case. The rider is to reflect the difference between Vectren's weather-normalized actual base revenues and the base revenues approved in the company's most recent case, adjusted for customer additions. The differences are to be deferred without carrying charges beginning in October, and each November 1st Vectren is to recover the accumulated difference over the subsequent 12 months.

In a Nov. 20, 2007 base rate filing, Vectren proposes to establish a distribution rate rider through which it would recover the costs associated with an accelerated main and service line replacement program.

In a Dec. 3, 2008 rate decision for Columbia Gas of Ohio, the PUC adopted a stipulation that included riders for infrastructure replacement costs and demand-side management program expenses (FN 12/5/08). (Section updated 12/8/08)

Public Utilities Commission of Nevada

Adjustment Clauses
Electric utilities are subject to a deferred energy cost recognition procedure, under which Commission approval is required prior to implementation of changes in the recovery of fuel and purchased power costs. In accordance with this procedure, Nevada Power Company (NPC) and Sierra Pacific Power (SPP) file annual deferred energy adjustment applications with the PUC to recover from, or refund to, customers balances that have been deferred. These deferred balances represent the difference between actual fuel and purchased power costs incurred and the amounts currently reflected in rates. The annual filings include a review of the purchased fuel and power transactions made during the previous year.

Legislation enacted in 2007 requires electric utilities to reset, on a quarterly basis, the rates for ongoing fuel and purchased power costs, referred to as the base tariff energy rate. The quarterly reset is designed to reflect more current fuel and purchased power costs, thereby eliminating large deferred energy balances, and minimizing the companies' exposure to fuel and purchased power expenses. These quarterly base tariff energy rate adjustments are reviewed annually by the PUC as part of the companies' annual deferred energy filings. The PUC may not allow recovery of any costs for fuel or purchased power that were the result of any imprudent practice or transaction. Costs eligible for recovery include all expenses incurred to purchase fuel, capacity, and energy, as well as the carrying charges on the deferred balances. The burden of proof rests with the utility.

Of note, deferred energy proceedings in the earlier part of this decade were contentious; namely, a 2002 decision for NPC in which the PUC disallowed about $437 million of a requested $922 million of deferred energy costs incurred by the company from March 1, 2001 through Sept. 30, 2001. About $180 million of the disallowance was related to the company's failure to enter into a purchased power contract with Merrill Lynch. NPC appealed the decision, which, in 2003, was upheld by the District Court. In 2006 the decision was reversed in part by the Supreme Court (SC), which then remanded the case to the PUC. The SC ruled that each of the PUC's findings in the 2002 decision was supported by the evidence in the record except the disallowance stemming from NPC's failure to enter into a contract with Merrill Lynch. The SC, therefore, reversed the PUC's disallowance associated with the Merrill Lynch issue. On remand, in 2007, the PUC approved a stipulation reached by NPC, the Bureau of Consumer Protection (BCP), the PUC Staff, and others that called for NPC to recover $189.9 million of deferred energy costs related to the Merrill Lynch issue, with no carrying charges on the unamortized balance, over 10 years commencing June 1, 2007. We note, however, that recent deferred energy decisions issued by the PUC have been much less contentious, and the PUC has, for the most part, allowed recovery of all requested costs.

In conjunction with the above decision on remand, the PUC approved recovery of $84 million of legal and settlement costs incurred by NPC to resolve claims associated with power supply contracts terminated during the 2000-2001 western energy crisis. Recovery of these costs, plus carrying charges, occurred over a three-year period beginning Jan.

1, 2007. In a separate but related proceeding, in November 2007, the PUC authorized SPP to recover $2.8 million of a requested $22.6 million in Enron-related contract settlement payments and legal fees.

In 2009, Senate Bill (S.B.) 358 was enacted requiring the PUC to adopt regulations for electric utilities that address the recovery of costs associated with energy efficiency and conservation programs. The PUC adopted regulations (ultimately approved by the Legislature on July 22, 2010) that are designed to allow electric utilities to recover the costs "reasonably" incurred and the lost revenue due to energy efficiency and conservation programs. The regulations state that the electric utilities may recover "an amount based on the measurable and verifiable effects of the implementation…of energy efficiency and conservation programs" included in the company's Commission-approved DSM plan. The regulations state that the PUC may permit an electric utility to recover any financial incentives offered to support customer participation in the conservation programs. The lost revenues for NPC and SPP are to be recovered using a balancing account.

Gas utilities are permitted to implement automatic quarterly gas cost adjustments based on historic, 12-month rolling average of actual costs. These adjustments are subject to annual prudence reviews.

In 2007, legislation was enacted requiring the PUC to establish regulations designed to remove the financial disincentives for natural gas utilities to support energy conservation efforts. The PUC-established rules, which were ratified by the Legislature in 2009, require a gas utility seeking decoupling to include, as part of its application, a discussion identifying any change in risk for the gas utility and a calculation to adjust for the change in risk. In 2009, the PUC adopted revenue decoupling mechanism for Southwest Gas. In so doing, the PUC ordered a 25-basis-point downward adjustment in the company's authorized equity return to account for the lower risk associated with decoupling.

Also in 2009, the PUC adopted a natural gas-related bad-debt tracking mechanism for Southwest Gas designed to allow the company to recover from, or refund to, ratepayers the differences between actual bad debt expenses and the level reflected in base rates (Section updated 4/25/11).

Public Utility Commission of Texas

Adjustment Clauses
For electric utilities that have not implemented retail competition, fuel and purchased power costs are recovered through a separate fuel factor, the level of which is established in base rate cases. Between base rate cases, the fuel factor may be adjusted, following hearings, based on projected fuel costs for the period the fuel factor will be in effect, subject to true-up. Capacity costs associated with purchased power are recovered through base rates, while energy costs are reflected in the fuel factor. Under- or over recoveries are deferred, with interest, for recovery over a subsequent 12 month period. El Paso Electric, Southwestern Public Service (SWPS), Southwestern Electric Power (SWEPCO), and Entergy Texas (ET) have not implemented retail competition, and continue to operate under the fuel factor mechanism.

For utilities that implemented retail competition, during the transition period, price-to-beat (PTB) rates charged by the affiliated retail electric providers (AREPs) were permitted to be adjusted up to twice annually to reflect changes in prices of natural gas and purchased energy (see the Electric Regulatory Reform/Industry Restructuring section). Now that the transition period has ended, all customers' prices are set essentially at the REPs' discretion. A REP must notify customers 45 days prior to a price change.

For the service territories in which retail competition has been implemented (i.e., within ERCOT), transmission is functionally separate from distribution, and while joint transmission and distribution rate cases may be filed, separate revenue requirements are identified for each function. In addition, transmission service providers (TSPs) are permitted to file up to twice annually to implement interim changes to reflect new transmission facilities through the transmission cost-of-service mechanism (TCOS). Transmission revenue requirements established through either base rates or the TCOS procedure are allocated among the distribution service providers (DSPs) within ERCOT based on PUC-approved, load-based allocation factors, established under the Commission's "transmission matrix."

The DSPs are permitted to adjust rates charged to retail electric providers (REPs) twice annually (in March and September) to reflect changes (versus levels reflected in existing base rates) in wholesale transmission costs assigned to the DSP by ERCOT. These changes flow through the transmission cost recovery factor (TCRF). To the extent cost changes occur between TCRF adjustments, the utility may now (beginning in 2010) defer the difference between actual transmission charges and the level of such charges reflected in rates charged to the REPs, with the deferred balance to be recovered over a period of 16 months beginning with the next TCRF adjustment. No carrying charges accrue on the deferred balances.

Utilities that have not implemented retail competition may file between rate cases (limited to once annually) for adjustments to reflect new investment in transmission facilities. This procedure is also known as a "TCRF mechanism." It is our understanding that no filings have been made under this procedure to date.

State law permits the utilities to recover costs associated with deployment of advanced metering technology through a separate surcharge, and the PUC has approved such mechanisms for CenterPoint Energy Houston Electric and Oncor Electric Delivery.

On Dec. 16, 2010, the PUC declined to adopt a distribution cost recovery factor mechanism to allow all DSPs (both within and outside of ERCOT) to adjust rates between rate cases to reflect new investment in the distribution system (FN 10/15/10). The PUC found that its authority to approve such a mechanism was unclear. (Section updated 1/20/11)

Railroad Commission of Texas

Adjustment Clauses

Purchased gas cost adjustment clauses may be implemented under certain circumstances. Specifically, the RRC must consider: (1) the ability of the pipeline or LDC to control prices for gas purchased, in light of by competition and relative competitive advantage; (2) the probability of frequent price changes; and, (3) the availability of alternative gas supply resources.

LDCs are permitted to implement surcharges between rate cases for recovery of costs associated with completed gas reliability infrastructure upgrades. In the context of a 2004 rate decision for Atmos Energy, the RRC approved the implementation of a gas cost recovery factor (GCRF) to reflect gas commodity cost changes that occur between rate cases. The GCRF is to be adjusted quarterly for changes in: projected gas costs for the prospective quarter; a true-up of projected and actual gas costs for the previous quarter; taxes; and, other costs (including lost and unaccounted for gas, and interest on under-/over-recoveries from the prior period). A gas cost prudence review is to be conducted every three years. As per a 2008 settlement with the majority of cities Atmos serves, gas-commodity-uncollectibles are to be recovered through the GCRF rather than base rates. The settlement also calls for implementation for a three-year period of a rate review mechanism (RRM), under which the company's operating expenses, revenues and rate base investments are to be reviewed annually, and rates are to be adjusted annually both to true-up under-/over-collections from the prior year and to reflect prospective changes. As per an RRC order issued on June 24, 2008, the changes to the GCRF will also apply to non-signatories; however, the RRM will not apply (see the Final Report dated 7/15/08).

As part of 2006 rate case filing, Atmos sought a "revenue stabilization" (decoupling) mechanism and a weather normalization adjustment (WNA) that would be based on 10 year average data. The parties subsequently reached an agreement, whereby Atmos was permitted to implement an interim WNA, effective Oct. 1, 2006, that was based on 30-year average data. In 2007, the RRC authorized Atmos to implement a WNA based on 10 years of historical data (versus the 30-year data included in the settlement). The revenue stabilization adjustment was not approved (FN 9/21/07). An annual cost of service adjustment (COSA) mechanism (similar to the RRM) was approved for CenterPoint Energy's Houston Division in 2008. A WNA is in place for certain areas served by Texas Gas Service, as is a COSA

(Section updated 1/20/11).

Rhode Island Public Utilities Commission

Adjustment Clauses
Prior to the implementation of electric industry restructuring in 1998, automatic electric fuel adjustment clauses were utilized by the utilities. In accordance with the restructuring law and PUC-approved restructuring plans, investor-owned utilities are to provide standard offer service to customers who do not select an alternative provider through 2020. The cost of providing this service is fully recoverable, with such recovery generally sought on a periodic basis.

In a 2008 gas rate decision for Narragansett Electric (NE), the PUC denied the company's proposed decoupling mechanism, concluding that there was insufficient evidence concerning its impact on ratepayers. If adopted, the mechanism would have been the first for a gas utility in New England. More recently, in a February 2010 electric rate decision, the PUC declined to adopt a revenue decoupling mechanism for NE's electric operations. We note, however, that since the issuance of those decisions, legislation was enacted (in May 2010) that directs the PUC to utilize revenue decoupling mechanisms for electric and certain gas utilities in the state. On Oct. 18, 2010, NE filed a request with the PUC to implement revenue decoupling mechanisms for its electric and gas operations.

NE recovers electric commodity-related uncollectibles, including associated administrative costs, through its standard offer service rate. In addition, the company recovers transmission-related bad debt through a transmission-related uncollectible mechanism.

The PUC utilizes an annual, semi-automatic gas cost recovery (GCR) clause for NE. The GCR establishes a deferred gas cost account that reconciles any over- or under-recoveries of gas costs in a later period. The PUC also utilizes an annual distribution adjustment clause (DAC) for NE's gas operations to recover costs associated with system balancing, low-income-assistance programs, demand-side management, and environmental response. Credits associated with margins from non-firm sales and transportation, earnings sharing, weather normalization, and service quality adjustments also flow through the DAC. Under NE's weather normalization clause, the company is required to return to gas customers the margin impact of weather that is 2% colder than normal, and may recover the margin impact of weather that is greater than 2% warmer than normal. For NE's gas operations, the PUC has approved rate recovery mechanism for the company's accelerated capital replacement program and pension and postretirement-benefits-other-than-pension expenses. (Section updated 12/6/10)

Public Service Comm. of South Carolina

Adjustment Clauses
Non-automatic electric fuel and purchased gas adjustment clauses are in place for the state's utilities. Each electric utility is required to furnish the PSC an estimate of its fuel costs, including the cost of purchased power, for a prospective 12-month period. The PSC then determines the fuel related costs to be included in base rates for that period, including adjustments for over- or under-recovery from the preceding 12-month period. Electric companies are required to account monthly for the difference between fuel costs recovered through base rates and actual fuel costs. Emissions allowance costs and the cost of certain materials used in reducing or treating emissions are reflected in the fuel clause.

Gas utilities use an adjustment clause that enables the pass through to customers of increases or decreases in the cost of gas. The companies' rates are based on the projected cost of gas, with differences between actual and projected costs deferred and reviewed by the PSC. Pursuant to a settlement, South Carolina Electric & Gas (SCE&G) makes monthly adjustments to its gas costs that are calculated based on a rolling 12-month forecast of purchased gas costs. Piedmont Natural Gas' costs are projected for a 12-month period and reviewed annually by the PSC.

On July 15, 2010, the Commission authorized SCE&G a 12-month pilot electric weather normalization mechanism for residential and small general service commercial customers. Gas weather normalization adjustments have been in place for several years for SCE&G and Piedmont Natural Gas that apply to residential and small commercial customers during winter months. (Section updated 7/27/10)

South Dakota Public Utilities Commission

Adjustment Clauses

Automatic fuel, purchased power, and gas cost adjustment clauses are permitted. Through these clauses, the utilities recover actual fuel, purchased power (energy portion only), and purchased gas expenses incurred; carrying costs accrue on unrecovered balances. Northern States Power (NSP) flows to ratepayers a portion of certain margins from wholesale power sales through its fuel clause. Black Hills Power (BHP) utilizes a fuel and purchased power adjustment clause (FPPAC) that allows the company to recover fuel and purchased power expenses and includes several sharing provisions. (Further details concerning the above-mentioned sharing provisions are provided in the Alternative Regulation section).

The PUC is statutorily authorized to approve implementation of automatic adjustment mechanisms to facilitate the recovery of the capital and operating costs associated with investment in transmission facilities. In addition, the law permits utilities operating under such mechanisms to earn a cash return on construction work in progress (CWIP) associated with transmission projects. Utilities are required to seek PUC approval in order to earn a cash return on CWIP on eligible projects through the mechanism. In December 2008, the PUC authorized Northern States Power (NSP) to implement a transmission cost recovery (TCR) mechanism. The company's filing had included a request to earn a cash return on CWIP; however, this was moot, as the related transmission assets had achieved commercial operation prior to PUC approval of the request. The TCR rider became effective in 2009, and is subject to annual adjustments.

Black Hills Power (BHP) utilizes a transmission cost adjustment (TCA) clause that is adjusted on an annual basis and reflects the flow through of costs allocated to the utility by the Federal Energy Regulatory Commission.

The PUC is permitted to approve implementation of automatic adjustment mechanisms to facilitate recovery of the capital and operating costs associated with environmental compliance projects at existing generation plants. In addition, companies operating under such a mechanism may seek PUC approval to earn a cash return on the related CWIP. In December 2008, the PUC authorized NSP to implement an environmental cost recovery (ECR) rider; the company did not request to earn a cash return on CWIP, as NSP did not have any eligible projects underway at the time of the filing. The ECR rider became effective in 2009, and is subject to annual adjustments. (Section updated 3/25/11)

Tennessee Regulatory Authority

Adjustment Clauses

Automatic purchased power, and gas commodity recovery clauses are permitted. The state's gas utilities are allowed to reflect a portion of uncollectible expenses in these clauses. Kingsport Power (KP) has a purchased power adjustment rider that reflects any changes in the wholesale costs of the company's power supplier, affiliate Appalachian Power (APCO). KP has no generating capacity of its own, and purchases 100% of its power requirements from APCO.

Atmos Energy utilizes an environmental cost recovery rider for certain compliance costs. Weather normalization adjustment riders are in place for Piedmont Natural Gas and Atmos Energy. Adjustments are made at the end of each meter-reading cycle. "Normal" weather is based on the most recent 30-year period.

On May 24, 2010, the TRA authorized Chattanooga Gas to implement three-year pilot program that includes a full revenue decoupling mechanism and energy conservation programs. (Section updated 3/24/11)

Vermont Public Service Board

Adjustment Clauses

Power cost adjustment (PCA) and purchased gas adjustment (PGA) mechanisms are permitted, provided that such mechanisms are part of an overall alternative regulation plan (see the Alternative Regulation section). Green Mountain Power (GMP) has a PCA in place that allows the company to adjust rates on a quarterly basis to recover from, or flow through to customers, power cost variances that exceed $0.3 million per quarter. Central Vermont Public Service's (CVPS') PCA allows for rates to be adjusted on a quarterly basis to recover or flow through to customers power cost variances that exceed $0.3 million per quarter. The PCA commenced Jan. 1, 2009.

Vermont Gas Systems, Inc. (VGS) has a PGA mechanism in place that allows for the recovery of gas-cost variations on a quarterly basis subject to a deadband that excludes $50,000 of such costs, positive or negative, in each quarter, and is designed to allow VGS to retain 10% of the gains or absorb 10% of the losses outside of the deadband.

We note that the ARPs adopted by the PSB for GMP, CVPS and VGS somewhat obviate the need for revenue decoupling mechanisms, as the plans allow for annual rate adjustments based on the company's forecast of sales and costs and contain earnings sharing provisions that minimize losses if sales deviate significantly from forecast. (Section updated 11/23/10)

Virginia State Corporation Commission

Adjustment Clauses

Electric fuel (the fuel adjustment clause [FAC]) and purchased gas adjustments (PGA) provisions are permitted. State law also permits recovery of various other costs through adjustment mechanisms.

FAC proceedings--The SCC's FAC procedure provides for electric rates to be reset annually on the basis of projected usage and costs. The utilities maintain accounts for any over- or under accruals, and these balancing accounts are reconciled through the following year's fuel factor. Purchased power energy and capacity charges for "economy" purchases are included in the fuel factor calculation. Energy charges associated with reliability purchases may flow through the fuel factor; but capacity charges are recovered through base rates.

As part of a stipulated restructuring-related corporate separation plan, under which Delmarva Power & Light divested its generation assets, the company's fuel factor was capped at then-existing levels, with no ability to defer excess costs, until Jan. 1, 2004. After that date, the stipulation called for Delmarva's fuel rates to be set based on a "Fuel Index Procedure" (FIP) designed to provide a proxy for the level of fuel cost increases that Delmarva would have experienced had the company not divested its generation assets. Issues subsequently arose regarding the continued effectiveness of the FIP, and in 2008 Delmarva sold its Virginia business to an electric cooperative (see the Merger Activity section).

As part of a corporate separation plan approved by the SCC following a Memorandum of Understanding (MOU), in

2000, Potomac Edison (PotEd) transferred its generation assets (367 MW) to affiliate Allegheny Energy Supply. Supply provided the power to meet PotEd 's customer requirements at fixed prices through June 30, 2007. PotEd 's FAC was essentially eliminated, and base rates were to be frozen through June 30, 2007, per the state's initial restructuring law. Due to subsequent modifications to the statute, and related rate freeze extensions, recovery of PotEd's post-June 30, 2007 power costs became controversial. PotEd ultimately divested its distribution operations in Virginia (see the Merger Activity section).

Environmental Compliance/Reliability--State statutes permitted the electric utilities other than Virginia Electric & Power (VEPCO) to file for "rate freeze exceptions" in order to begin recovering costs associated with environmental compliance and reliability improvement programs. Such costs were permitted to be recovered through an Environmental & Reliability Factor (ERF).

In 2006, the SCC authorized Appalachian Power (APCO) to implement an ERF. Updates were approved in 2007, 2008 and 2009, and the final ERF increase was approved on Jan. 14, 2010, bringing the total annual revenue requirement recovered through the rider to $89.5 million. This revenue requirement reflects a 10.6% return on equity (41.525% of capital) and a 7.877% return on a rate base estimated at $843 million to $871 million (FN 1/15/10).

Generation--As permitted by state law enacted in 2007, APCO filed for implementation of a surcharge designed to recover the costs associated with the proposed construction of a new 629-MW integrated gasification combined-cycle (IGCC) generation plant, effective Jan. 1, 2009 (Case No. PUE-2007-00068). However, in April 2008, the SCC rejected the IGCC proposal.

In 2008, the Commission authorized VEPCO to implement an annually adjusted surcharge (Rider S) to achieve rate recognition of the Virginia City Hybrid Energy Center (VCHEC), with the surcharge to: allow VEPCO to earn a cash return on construction-work-in-progress related to the facility; and, include a 100-basis-point return on equity (ROE) adder for the investment in VCHEC.

In 2009, the SCC approved VEPCO's request for approval to construct the Bear Garden generation facility and to recover the costs associated with the facility through a surcharge (Rider R) similar to Rider S. Rider R is to reflect a 100-basis-point ROE adder as well.

Transmission--In 2009, the SCC approved VEPCO's request to implement a transmission-cost-recovery rider (Rider T), effective Sept. 1, 2009, with an initial annual revenue requirement of $217.8 million. We note that the initial revenue requirement included $149.4 million that was previously reflected in VEPCO's base rates; the new rider, therefore, represented a $68.4 million overall rate increase for VEPCO customers (FN 7/2/09). Rider T is adjusted annually.

In 2009, APCO filed for approval of a transmission revenue adjustment clause (T-RAC). The SCC approved an agreement establishing a T-RAC mechanism with an initial revenue requirement of $91.1 million (including $69.4 million that was previously reflected in base rates and $21.7 million of incremental revenue) (FN 9/4/09). The T-RAC is adjusted annually.

Energy Efficiency--On March 24, 2010, the SCC approved certain new energy efficiency/demand-side management programs proposed by VEPCO, and granted the company's request to implement surcharge mechanisms for recovery of the associated costs (FN 3/26/10).

Gas Costs--The PGA provides for quarterly rate changes to reflect fluctuations in gas costs. There is an annual reconciliation of total billed gas charges with actual gas costs. Any deficiency or excess is deferred, and the balance is either recovered or refunded in the 12 months following the annual reconciliation. Washington Gas Columbia Gas of Virginia (CGV) are also permitted to recover carrying charges on storage gas balances and over/under-collected gas costs, hexane costs, and commodity-related uncollectibles expense.

Weather Normalization/Decoupling--A Weather Normalization Adjustment (WNA) Rider is in place for Virginia Natural Gas (VNG). Separate WNA factors are calculated for each customer class, such that when applied to the billed volumes for each rate class as a surcharge or credit, the WNA factors produce a bill that recovers VNG's cost of service as approved by the SCC under normal weather conditions. Similar programs are in place for Roanoke Gas, Southwestern Virginia Gas, CGV, and Washington Gas.

In 2008, the SCC approved a revenue normalization adjustment (decoupling) mechanism designed to mitigate the impact on VNG's revenues of residential customer participation in energy conservation programs. A similar mechanism has been approved for Washington Gas and CGV.

Gas Infrastructure--Legislation enacted in 2010, known as Steps to Advance Virginia's Energy Plan (SAVE Act), authorizes a natural gas utility that invests in natural gas facility replacement projects to recover, in the form of a SAVE rider, a return on investment, a revenue conversion factor, depreciation, property taxes and carrying costs on over/under recovery of these costs. Eligible infrastructure replacement is defined as natural gas facility replacement projects that (i) enhance safety or reliability by reducing system integrity risks associated with customer outages, corrosion, equipment failures, material failures, or natural forces; (ii) do not increase revenues by directly connecting the infrastructure replacement to new customers; (iii) reduce or have the potential to reduce greenhouse gas emissions; (iv) are commenced on or after January 1, 2010; and (v) are not included in the natural gas utility's rate base in its most recent rate case. (Section updated 3/30/11)

Washington Utilities and Transport Comm

Adjustment Clauses

Until 2002, power cost adjustment mechanisms (PCAMs) were not in effect, and the electric utilities were at risk for fluctuations in fuel and purchased power costs between rate cases. However, in certain cases prior to the establishment of PCAMs, the WUTC permitted the deferral of power costs that were in excess of the level being recovered through base rates.

As part of a general rate case, in 2002, the WUTC adopted a settlement that established an Energy Recovery Mechanism (ERM) for Avista Corporation that allows the company to adjust rates to reflect changes in power supply-related costs. The ERM has been modified since its inception, and as specified in a December 2008 rate decision, 75% of any energy cost savings flow to customers and 25% to the company when annual power costs are between $4 million and $10 million lower than those included in base rates. Equal sharing is to occur (in the $4 million $10 million band) when actual power costs are greater than the amount included in base rates. Any differences in excess of $10 million are to be allocated 90% to customers and 10% to shareholders. As part of a settlement approved in Avista's 2010 general rate case, the ERM was suspended for the remainder of 2010.

A PCAM was implemented in 2002 for Puget Sound Energy (PSE) following a settlement. The PCAM allows for variations in power costs to be apportioned, on a graduated scale, between the company and customers. Specifically, if power costs are above (or below) the PCAM baseline amount, PSE is to absorb (or retain) the first $20 million above (or below) the baseline, 50% of the next $20 million, 10% of the next $80 million, and 5% of any amount that exceeds $120 million. PSE is also permitted to request a PCAM rate surcharge if, for any 12 month period, the projected deferred power costs are expected to exceed $30 million.

On Nov. 4, 2010, the WUTC issued a policy statement on decoupling. However, we note that limited decoupling plans were approved previously for certain utilities' gas operations (see below). The WUTC indicated that adoption of decoupling mechanisms for electric and gas utilities would be considered in the context of a rate case, with revenue recovery conditioned upon a utility's level of achievement with respect to its conservation targets. The WUTC indicated that it would consider adoption of a full decoupling mechanism ("designed to minimize the risk to both the utilities and to ratepayers of volatility in average use per customer by class regardless of cause, including the effects of weather"), for electric and gas utilities. The WUTC indicated that it would only consider limited decoupling mechanisms (described as a lost margin recovery mechanism that would allow the utility to recovery lost margin due only to the utility's conservation efforts including educational and informational) for gas utilities. We note that such limited decoupling plans for gas utilities have been adopted in the past (see below). The Commission indicated that a proposal to implement such mechanisms is to contain several elements including: (1) a true-up mechanism, (2) impact on rate of return, and, (3) an earnings test.

We note that as part of a settlement reached in connection with the acquisition of PSE parent Puget Energy Inc. by Puget Holdings LLC, PSE agreed to refrain from proposing a decoupling mechanism for its electric and gas operations until at least early-2011.

Purchased gas adjustment (PGA) mechanisms are currently in effect that allow PSE and Avista to recover fixed gas costs through per-therm rates, at forecasted levels. Deferred accounting is required for over- and under-recovered fixed charges collected during periods when actual gas volumes delivered differ from forecasted demand.

In 2007, the WUTC approved a partial decoupling mechanism (i.e., weather adjusted) for Cascade Natural Gas (CNG) to be in effect on a three-year pilot basis effective Oct. 1, 2007, the terms of which were agreed to in a settlement. Approval of the decoupling mechanism was subject to WUTC approval of a conservation plan, which was subsequently approved by the Commission. Earnings were to be capped at the company's overall rate of return. Penalties were to be levied if CNG failed to meet established conservation benchmarks and targets. The pilot, which ended on Sept. 30, 2010, was only to be extended if requested as part of a general rate case. While CNG has not filed a rate case, the company filed a request on Oct. 1, 2010, seeking to extend the mechanism. The request was ultimately withdrawn after the WUTC issued its Nov. 4, 2010 policy statement regarding regulatory mechanisms, including decoupling.

Since 2007, Avista has operated under a decoupling mechanism that applies only to residential and small commercial gas customers. The plan was initially adopted in February 2007, and was to be in place on a 2½-year pilot basis, beginning in Jan. 1, 2007. Avista deferred 90% of the margin difference (i.e., fixed cost), which was to be recovered from or returned to customers. The recovery of any deferred costs was subject to both an earnings test that would prohibit collection if Avista is earning above its authorized rate of return, and a demand-side management (DSM) test that would prohibit collection if specific conservation targets were not achieved. Rate adjustments associated with the mechanism in any one year were limited to no more than 2%. The mechanism was extended beyond the end of the pilot period (June 30, 2009) and the WUTC subsequently authorized Avista to continue to use its natural gas decoupling mechanism, with modifications. Specifically, Avista is to defer 45% of the margin difference, with the recovery of any deferred costs to continue to be subject to an earnings test and a DSM test. Rate adjustments associated with the mechanism are to continue to be limited to no more than 2%. (Section updated 1/20/11)

Wyoming Public Service Commission

Adjustment Clauses

Historically, recovery of electric fuel and purchased power costs has been addressed in base rate cases; however, PacifiCorp and Cheyenne Light, Fuel & Power (CLF&P) now recover power costs through a power cost adjustment mechanism (PCAM) (see below).

In 2006, the PSC adopted a settlement that provided for PacifiCorp to implement a PCAM that provides for recovery of total net power costs (NPC) and tracks the company's aggregate power costs over a 12-month period (Dec. 1-Nov. 30), with annual PCAM filings due each Feb. 1. In these filings, actual NPC incurred by the company during the period is compared to a baseline NPC level established in a rate case. The PCAM rate is adjusted annually, effective April 1, reflecting any variations from the established level and amortized over the subsequent 12-month period, subject to a graduated sharing mechanism. The PCAM is scheduled to expire on March 31, 2012. On Feb. 4, 2011, the PSC issued an order authorizing PacifiCorp to operate under an energy cost adjustment mechanism (ECAM) following the expiration of the PCAM, for a five-year period beginning on April 1, 2012. (For information concerning the sharing provisions of PacifiCorp's PCAM and ECAM, see the Alternative Regulation section.)

In 2007, the PSC adopted a settlement that provides for CLF&P to utilize a PCAM, whereby the company recovers "significant" changes in fuel and purchased power costs between base rate proceedings. The PCAM includes sharing provisions (see the Alternative Regulation section).

The state's gas utilities are authorized to seek recovery of the difference between actual and estimated gas costs through a semi-automatic purchased gas adjustment (PGA) mechanism. Gas cost increases may be recovered on an interim basis pending the outcome of hearings. Gas utilities may retain a portion of gas-procurement cost savings relative to the most recently approved PGA rate (see the Alternative Regulation section). Deferred accounting and the reconciliation of under- and over-recovered balances are permitted.

In 2008, the PSC authorized PacifiCorp to implement a surcharge to recover costs associated with a demand-side management (DSM) program for the company's electric operations. The program is for an initial three-year term extending to Dec. 31, 2012; the program may continue beyond the initial term unless terminated by the PSC. PacifiCorp's DSM program includes a variety of efficiency and weatherization measures for various customer classes.

On Dec. 23, 2010, the PSC authorized SourceGas Distribution to implement a decoupling mechanism for its small and medium general service class distribution customers beginning in January 2012. The mechanism excludes revenue variations due to weather. (Section updated 4/29/11)