COST RECOVERY MECHANISMS
WORKPAPERS
FINANCO INC.

ALLETE

Allete

Electric Rates. Minnesota Power designs its electric service rates based on cost of service studies under which allocations are made to the various classes of customers. Nearly all retail sales include billing adjustment clauses, which adjust electric service rates for changes in the cost of fuel and purchased energy, recovery of current and deferred conservation improvement program expenditures and recovery of certain environmental and renewable expenditures.

Keywords
- clause
- rider
- mechanism
- track

ALLETE

Regulated Operations includes retail and wholesale rate-regulated electric, natural gas, and water services in northeastern Minnesota and northwestern Wisconsin along with our Investment in ATC. Minnesota Power provides regulated utility electric service to 144,000 retail customers in northeastern Minnesota. SWL&P, a wholly-owned subsidiary, provides regulated utility electric, natural gas and water service in northwestern Wisconsin to 15,000 electric customers, 12,000 natural gas customers and 10,000 water customers. Regulated utility rates are under the jurisdiction of Minnesota, Wisconsin and federal regulatory authorities. Billings are rendered on a cycle basis. Revenue is accrued for service provided but not billed. Regulated utility electric rates include adjustment clauses that: (1) bill or credit customers for fuel and purchased energy costs above or below the base levels in rate schedules; (2) bill retail customers for the recovery of conservation improvement program expenditures not collected in base rates; and (3) bill customers for the recovery of certain environmental and renewable energy expenditures. Fuel and purchased power expense is deferred to match the period in which the revenue for fuel and purchased power expense is collected from customers pursuant to the fuel adjustment clause. Our Investment in ATC includes our approximate 8 percent equity ownership interest in ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. ATC provides transmission service under rates regulated by the FERC that are set in accordance with the FERC's policy of establishing the independent operation and ownership of, and investment in, transmission facilities. (See Note 6. Investment in ATC.)

Emission Reduction Plans We have made investments in pollution control equipment at our Boswell Unit 3 generating unit that reduces particulates, SO_2, NO_X and mercury emissions to meet future federal and state requirements. This equipment was placed in service in November 2009. During the construction phase, the MPUC authorized a cash return on construction work in progress in lieu of AFUDC, and this amount was collected through a current cost recovery rider. Our 2010 rate case proposes to move this project from a current cost recovery rider to base rates.

Boswell Unit 3 Environmental Rider

REGULATED OPERATIONS (Continued)
Regulatory Matters (Continued)

Transmission. We have an approved cost recovery rider in-place for certain transmission expenditures, and our current billing factor was approved by the MPUC in June 2009. The billing factor allows us to charge our retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested. Our 2010 rate case proposes to move completed transmission projects from the current cost recovery rider to base rates.

Conservation Improvement Program (CIP). Minnesota requires electric utilities to spend a minimum of 1.5 percent of gross operating revenues from service provided in the state on energy CIPs each year. These investments are recovered from retail customers through a billing adjustment and amounts included in retail base rates. The MPUC allows utilities to accumulate, in a deferred account for future cost recovery, all CIP expenditures, as well as a carrying charge on the deferred account balance. Minnesota's Next Generation Energy Act of 2007 introduced, in addition to minimum spending requirements, an energy-saving goal of 1.5 percent of gross annual retail electric energy sales by 2010. In June 2008, a biennial filing was submitted for 2009 through 2010, and subsequently approved by the OES. For future program years, Minnesota Power will build upon current successful CIPs in an effort to meet the newly established 1.5 percent energy-saving goal. Minnesota Power's CIP investment goal was $4.6 million for 2009 ($3.7 million for 2008; $3.2 million for 2007), with actual spending of $5.5 million in 2009 ($4.8 million in 2008; $3.9 million in 2007).

Regulated Operations

Operating revenue decreased $30.4 million, or 4 percent, from 2008 due to lower fuel and purchased power recoveries, lower retail and municipal kilowatt-hour sales, lower natural gas revenue at SWL&P, and the accrual of prior year retail rate refunds related to our 2008 retail rate case. These decreases were partially offset by higher sales to Other Power Suppliers, higher FERC-approved wholesale rates and increased revenue from MPUC-approved current cost recovery riders.

Lower fuel and purchased power recoveries along with a decrease in retail and municipal kilowatt-hour sales combined for a total revenue reduction of $116.2 million. Fuel and purchased power recoveries decreased due to a reduction in fuel and purchased power expense. (See Fuel and Purchased Power Expense.) Total kilowatt-hour sales to retail and municipal customers decreased 26 percent from 2008 primarily due to idled production lines and temporary closures at some of our taconite customers' plants.

Natural gas revenue at SWL&P was lower by $7.8 million due to a 27 percent decrease in the price of natural gas and a 9 percent decline in sales. Natural gas revenue is primarily a flow-through of the natural gas costs. (See Operating and Maintenance Expense.)

Prior year retail rate refunds resulting from the 2009 MPUC Order and August 2009 Reconsideration Order were recorded in 2009 and resulted in a reduction in revenues of $7.6 million.

The decrease in kilowatt-hour sales to retail and municipal customers has been partially offset by revenue from marketing the power to Other Power Suppliers, which increased $77.2 million in 2009. Sales to Other Power Suppliers are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations.

Higher rates from the March 1, 2008, and February 1, 2009, FERC-approved wholesale rate increases for our municipal customers increased revenue by $13.2 million.

MPUC-approved current cost recovery rider revenue increased $10.4 million in 2009 from 2008 primarily due to increased capital expenditures related to our Boswell Unit 3 emission reduction plan.

CapX2020 Minnesota Power is a participant in the CapX2020 initiative which represents an effort to ensure electric transmission and distribution reliability in Minnesota and the surrounding region for the future. CapX2020, which includes Minnesota's largest transmission owners, consists of electric cooperatives, municipals and investor-owned utilities, and has assessed the transmission system and projected growth in customer demand for electricity through 2020. Studies show that the region's transmission system will require major upgrades and expansion to accommodate increased electricity demand as well as support renewable energy expansion through 2020.

Minnesota Power intends to invest in two lines, a 250-mile 345 kV line between Fargo, North Dakota and Monticello, Minnesota, and a 70-mile, 230 kV line between Bemidji and Grand Rapids, Minnesota. The MPUC issued the Certificate of Need for the 230 kV line in July 2009. The MPUC decision on the Route Permit application is expected in 2010. Our total investment in these lines is expected to be approximately $100 million. We intend to seek recovery of these costs in a filing with the MPUC in the first quarter of 2010, **under a Minnesota Power transmission cost recovery tariff rider authorized by Minnesota legislation**. Construction of the lines is targeted to begin in late 2010 and may take up to four years.

Emission Reduction Plans We have made investments in pollution control equipment at our Boswell Unit 3 generating unit that reduces particulates, SO_2, NO_x and mercury emissions to meet future federal and state requirements. This equipment was placed in service in November 2009. During the construction phase, the MPUC authorized a cash return on construction work in progress in lieu of AFUDC, and this amount was collected through a current cost recovery rider. Our 2010 rate case proposes to move this project from a current cost recovery rider to base rates.

The environmental regulatory requirements for Taconite Harbor Unit 3 are pending approval of the Minnesota Regional Haze implementation by the EPA. We are evaluating compliance requirements for this Unit. Environmental retrofits at Laskin and Taconite Harbor Units 1 and 2 have been completed and are in-service.

Boswell NO_X Reduction Plan. In September 2008, we submitted to the MPCA and MPUC a $92 million environmental initiative proposing cost recovery for expenditures relating to NO_X emission reductions from Boswell Units 1, 2, and 4. The Boswell NO_X Reduction Plan is expected to significantly reduce NO_X emissions from these units. In conjunction with the NO_X reduction, we plan to make an efficiency improvement to our existing turbine/generator at Boswell Unit 4 adding approximately 60 MWs of total output. The Boswell 1, 2 and 4, selective non-catalytic reduction NO_X controls are currently in service, while the Boswell 4 low NO_X burners and turbine efficiency projects are anticipated to be in service in late 2010. Our 2010 rate case seeks recovery for this project in base rates.

Alliant Energy Co.

Alliant (Iowa, W.sc.) IPL WPL

Retail Commodity Cost Recovery Mechanisms - IPL's retail electric and natural gas tariffs contain an automatic adjustment clause for changes in prudently incurred commodity costs required to serve its retail customers. Any over/under collection of commodity costs for each given month are automatically reflected in future billings to retail customers.

New Electric Generating Facilities - A Certificate of Public Convenience, Use and Necessity (GCU Certificate) application is required to be filed with the IUB for construction approval of any new electric generating facility located in Iowa with 25 megawatts (MW) or more of capacity.

Advance Rate Making Principles - Iowa Code §476.53 (formerly referred to as HF 577) provides Iowa utilities with rate making principles prior to making certain generation investments in Iowa. Under Iowa Code §476.53, IPL must file for, and the IUB must provide, rate making principles for electric generating facilities located in Iowa that have received construction approval including new base-load (primarily defined as nuclear or coal-fired generation) facilities with a capacity of 300 MW or more, combined-cycle natural gas-fired facilities of any size and renewable generating resources, such as wind facilities, of any size. Upon approval of rate making principles by the IUB, IPL must either build the facility under the approved rate making principles, or not at all.

Public Service Commission of Wisconsin (PSCW) - Alliant Energy is subject to regulation by the PSCW for the type and amount of Alliant Energy's investments in non-utility businesses and other affiliated interest activities, among other issues. WPL is also subject to regulation by the PSCW related to its operations in Wisconsin for various issues including, but not limited to, retail utility rates and standards of service, accounting requirements, issuance and use of proceeds of securities, approval of the location and construction of electric generating facilities and certain other additions and extensions to facilities.

Retail Utility Base Rates - WPL files periodic requests with the PSCW for retail rate relief. These filings are required to be based on forward-looking test periods. There is no statutory time limit for the PSCW to decide retail rate requests. However, the PSCW attempts to process base retail rate cases in approximately 10 months and has the ability to approve interim retail rate relief, subject to refund, if necessary.

Retail Commodity Cost Recovery Mechanisms -
Electric - WPL's retail electric rates are based on estimates of annual fuel-related costs (includes fuel and purchased power energy costs) anticipated during the test period During each electric retail rate proceeding, the PSCW sets fuel monitoring ranges based on the forecasted fuel-related costs used to determine rates in such proceeding. If WPL's actual fuel-related costs fall outside these fuel monitoring ranges, the PSCW can authorize an adjustment to future retail electric rates.

The fuel monitoring ranges set by the PSCW consist of unit cost variances between monitoring levels and actual unit costs and include three different ranges based on monthly costs, cumulative costs and revised forecasted annual costs during the test-year period. In order for WPL, or others, to initiate a proceeding to change rates related to fuel-related costs during the test period, WPL, or others, must demonstrate: a) that either 1) any actual monthly costs during the test period exceeded the monthly ranges or 2) the actual cumulative costs to date during the test period exceeded the cumulative ranges; and b) that the annual projected costs (that include cumulative actual costs) for the test period also exceed the annual ranges. In December 2009, the PSCW approved an order continuing WPL's fuel monitoring ranges of plus or minus 8% for the monthly range; for the cumulative range, plus or minus 8% for the first month, plus or minus 5% for the second month, and plus or minus 2% for the remaining months of the monitoring period; and plus or minus 2% for the annual range. For fuel-only retail rate changes, the PSCW attempts to provide interim changes effective within 21 days of notice to customers. There is no statutory time limit for final fuel-only retail rate change decisions.

Natural Gas - WPL's retail natural gas tariffs contain an automatic adjustment clause for changes in prudently incurred natural gas costs required to serve its retail gas customers. Any over/under collection of natural gas costs for each given month are automatically reflected in future billings to retail customers.

Changes in commodity prices or the availability of commodities may increase the cost of producing electric energy or change the amount we receive from selling electric energy, harming our financial performance - The prices that we may obtain for electric energy may not compensate for changes in delivered coal, natural gas or electric energy spot-market costs, or changes in the relationship between such costs and the market prices of electric energy. As a result, we may be unable to pass on the changes in costs to our customers, especially at WPL where we do not have a retail automatic fuel cost adjustment clause, which allows more consistent and timely cost recovery. This may result in an adverse effect on our financial condition and results of operations. We are heavily exposed to changes in the price and availability of coal because the majority of the electricity generated by us is from our coal-fired generating facilities. We have contracts of varying durations for the supply and transportation of coal for most of our existing generating capability, but as these contracts end or otherwise are not honored, we may not be able to purchase coal on terms as favorable as the current contracts Further, we currently rely on coal primarily from the Powder River Basin in Wyoming and any disruption of coal production in, or transportation from, that region may cause us to incur additional costs and adversely affect our financial condition and results of operations. We also have responsibility to supply natural gas to certain natural gas-fired electric generating facilities that we own and lease, which increase our exposure to the more volatile market prices of natural gas. We have natural gas supply contracts in place which are generally short-term in duration. The natural gas supply commitments are either fixed price in nature or market-based. As some of the contracts are market-based, and all of the contracts are short-term, we may not be able to purchase natural gas on terms as favorable as the current contracts when the current contracts expire. Further, any disruption of production or transportation of natural gas may cause us to incur additional costs to purchase natural gas that may adversely impact our financial condition and results of operations. We buy electricity from the market, and sell our generation into the market. The market prices impact the volumes of electricity bought and sold and impact our results of operations. The derivative instruments we use to manage our commodity risks have terms allowing our counterparties to demand cash collateral. Extensive cash collateral demands could adversely impact our cash flows.

In October 2009, ITC filed with MISO the Attachment "O" rate it proposes to charge its customers in 2010 for transmission services. The proposed rate was based on ITC's net revenue requirement for 2010 as well as the impact of a true-up adjustment related to amounts that ITC under-recovered from its customers in 2008. The 2010 Attachment "O" rate is approximately 60% higher than the rate ITC charged IPL in 2009. Based on this proposed rate increase, IPL estimates the electric transmission service charges from ITC for 2010 will be approximately $85 million to $95 million higher than 2009. In January 2010, the IUB issued an order authorizing IPL to use $46 million of regulatory liabilities to offset the portion of the transmission service charges expected to be billed in 2010 related to ITC's 2008 true-up adjustment. IPL currently plans to file retail electric rate cases in Iowa and Minnesota in 2010 to address the recovery of the remaining expected increases in transmission services charges from ITC for 2010. Refer to "Rate Matters - Proposed Changes to Rate Recovery Mechanisms" for proposals made by IPL to each of the IUB and MPUC to implement an automatic adjustment clause for electric transmission service charges incurred by IPL to serve its utility customers. Alliant Energy and IPL are currently unable to predict the ultimate impact of ITC's proposed transmission rate increase for 2010, but believe it could have a material impact on their financial condition and results of operations in 2010.

Proposed Changes to Rate Recovery Mechanisms

IPL's Iowa Transmission Rider - In 2009, IPL filed a proposal with the IUB to implement an automatic cost recovery rider for annual changes in electric transmission service costs. The proposed automatic cost recovery rider would not require a base rate case for annual revisions of rates charged to IPL's Iowa retail electric customers, but would require that the electric transmission service costs incurred be fully reconciled against the revenues collected for such costs. In its January 2010 order, the IUB deferred the decision on IPL's proposal to IPL's next filed rate case.

IPL's Minnesota Transmission Rider - In January 2010, IPL filed a proposal with the MPUC to implement an automatic cost recovery rider for annual changes in electric transmission service costs. The proposed automatic cost recovery rider would not require a base rate case for annual revisions of rates charged to IPL's Minnesota retail electric customers, but would require that the electric transmission service costs incurred be fully reconciled against the revenues collected for such costs. IPL is currently unable to determine when the MPUC will take action on this request.

Commodity Price - Alliant Energy, IPL and WPL are exposed to the impact of market fluctuations in the price and transportation costs of commodities they procure and market. Alliant Energy, IPL and WPL employ established policies and procedures to mitigate their risks associated with these market fluctuations including the use of various commodity derivatives and contracts of various durations for the forward sale and purchase of these commodities. Specifically, IPL and WPL have entered into several commodity derivative instruments to substantially hedge their open positions related to electric supply in 2010. However, IPL and WPL still have some exposure to commodity risk as a result of changes in their forecasted electric demand, expected availability of their generating units and the limitations of WPL's Electric Risk Management Plan (ERMP) discussed below. Alliant Energy's exposure to commodity price risks in its utility business is also significantly mitigated by current rate making structures in place for recovery of its electric production fuel and purchased energy expenses (fuel-related costs) as well as its cost of natural gas purchased for resale. **IPL's electric and gas tariffs and WPL's gas and wholesale electric tariffs provide for subsequent adjustments to** its rates for changes in prudently incurred commodity costs. **IPL's and WPL's rate mechanisms, combined with commodity derivatives, significantly reduce commodity risk associated with their electric and gas margins.**

WPL's **retail electric margins have the most exposure to the impact of changes in commodity prices** for Alliant Energy and WPL due largely to the current retail recovery mechanism in place in Wisconsin for fuel-related costs. WPL's retail electric rates approved by the PSCW are based on forecasts of forward-looking test year periods and include estimates of future fuel-related costs per MWh anticipated during the test period. During each electric retail rate proceeding for WPL that includes fuel-related costs, the PSCW sets fuel monitoring ranges based on the forecasted fuel-related costs used to determine base rates. If WPL's actual fuel-related costs fall outside these fuel monitoring ranges during the test period, WPL and/or other parties can request, and the PSCW can authorize, an adjustment to future retail electric rates based on changes in fuel-related costs only. The PSCW on its own, or at the request of a party to the case, including WPL, can request that the PSCW set rates subject to refund pending a review of fuel-related costs. As part of this process, the PSCW may authorize an interim fuel-related rate increase or decrease until final rates are approved. However, if an interim rate increase is granted and the final rate increase is less than the interim rate increase, WPL must refund the excess collection to retail customers with interest at the current authorized return on common equity rate. As part of WPL's 2010 retail rate case order effective Jan. 1, 2010, the PSCW approved annual forecasted fuel-related costs per MWh of $27.46 based on $378 million of variable fuel costs for WPL's 2010 test period and left unchanged the annual fuel monitoring range of plus or minus 2%.

Based on this current retail recovery mechanism, Alliant Energy and WPL have exposure to WPL's retail electric margins from increases in fuel-related costs above the forecasted fuel-related costs per MWh used to determine electric rates to the extent such increases are not recovered through prospective fuel only retail rate changes. Alliant Energy and WPL have additional commodity price risk resulting from the lag inherent in obtaining any approved retail rate relief for potential increases in fuel-related costs above the fuel monitoring ranges and the prospective nature of any retail rate relief, which precludes WPL from recovering previously under-recovered costs from ratepayers in the future. Alliant Energy and WPL are unable to determine the impact of changes in commodity prices on their future retail electric margins given the uncertainty of how future fuel-related costs will correlate with the retail electric rates in place and the outcome of the proposed changes to the current retail electric fuel-related cost recovery rules in Wisconsin. Refer to "Rate Matters" for additional details of the retail rate recovery mechanism in Wisconsin for electric fuel-related costs including potential changes to WPL's electric fuel-related cost recovery mechanism.

In October 2008, the PSCW issued an order approving an ERMP for WPL that expires in December 2010. The ERMP determines hedging options for WPL's electric operations and which costs of hedging transactions can be included in fuel costs for purposes of cost recovery. The ERMP was developed with the involvement of individuals representing key customer groups as well as PSCW staff, and as proposed, included a number of new elements that would expand WPL's hedging options, including longer time horizons and greater protections for decisions made to take advantage of unusual market conditions. However, in approving the ERMP, the PSCW added a new limitation that WPL may not hedge more than a cumulative 75% of a future month's expected open position (expected electric system demand less expected generation and firm purchases) although this limitation may be waived for the month immediately preceding the future month in order to assure reliable provision of service.

WPL MISO-related costs - In August 2007, the PSCW issued an order requiring WPL to discontinue, effective Dec. 31, 2007, the deferral of the retail portion of certain costs incurred by WPL to participate in the MISO market. WPL incurred $10 million of deferred retail costs prior to 2008 to participate in the MISO market that were recognized in regulatory assets on Alliant Energy's and WPL's Consolidated Balance Sheets. In December 2008, WPL received approval from the PSCW to recover the $10 million of deferred retail costs over a two-year period ending December 2010. MISO costs incurred after Dec. 31, 2007 are subject to recovery through WPL's retail electric fuel-related cost recovery mechanism.

(h) Utility Cost Recovery Mechanisms -
Electric Production Fuel and Energy Purchases - IPL and WPL burn coal and other fossil fuels to produce electricity at their generating facilities to meet the demand of their customers and charge the cost of fossil fuels used during each period to electric production fuel expense. IPL and WPL also purchase electricity to meet the demand of their customers and charge these costs to energy purchases expense.

The tariffs for IPL's retail electric customers and IPL's and WPL's wholesale electric customers provide for subsequent adjustments to their electric rates for changes in electric production fuel and purchased energy expenses. Changes in the under/over collection of these expenses are also recognized in electric production fuel and energy purchases expense. The cumulative effects of the under/over collection of these costs are recorded in Alliant Energy's, IPL's and WPL's Consolidated Balance Sheets as current regulatory assets or current regulatory liabilities until they are reflected in future billings to customers.

WPL's retail electric rates approved by the PSCW are based on forecasts of forward-looking test periods and include estimates of future electric production fuel and purchased energy expenses (fuel-related costs) anticipated during the test period. During each electric retail rate proceeding, the PSCW sets fuel monitoring ranges based on the forecasted fuel-related costs used to determine retail base rates. If WPL's actual fuel-related costs fall outside these fuel monitoring ranges during the test period, WPL and/or other parties can request, and the PSCW can authorize, an adjustment to future retail electric rates based on changes in fuel-related costs only. The PSCW may authorize an interim retail rate increase. However, if the final retail rate increase is less than the interim retail rate increase, WPL must refund the excess collection to retail customers with interest at the current authorized return on common equity rate.

Purchased Electric Capacity - IPL and WPL enter into purchased power agreements (PPAs) to help meet the electricity demand of their customers. Certain of these PPAs include minimum payments for IPL's and WPL's rights to electric generating capacity, which are charged to purchased electric capacity expense. Purchased electric capacity expenses are recovered from the retail electric customers of IPL and WPL through changes in base rates determined during periodic rate proceedings. Purchased electric capacity expenses are recovered from wholesale electric customers of IPL and WPL through annual changes in base rates determined by a formula rate structure.

Electric Transmission Service - IPL and WPL incur costs for the transmission of electricity to their customers and charge these costs to electric transmission service expense. Electric transmission service expenses are recovered from retail electric customers of IPL and WPL through changes in base rates determined during periodic rate proceedings. Electric transmission service expenses are recovered from wholesale electric customers of IPL and WPL through annual changes in base rates determined by a formula rate structure. Electric transmission service expenses for Alliant Energy and IPL are significantly higher in 2009 and 2008 compared to 2007 due to electric transmission service expenses billed to IPL by ITC following the sale of IPL's electric transmission assets to ITC in December 2007.

Cost of Gas Sold - IPL and WPL incur costs for the purchase, transportation and storage of natural gas to serve their gas customers and charge these costs to cost of gas sold. The tariffs for IPL's and WPL's retail gas customers provide for subsequent adjustments to their rates for changes in the cost of gas sold. Changes in the under/over collection of these costs are also recognized in cost of gas sold. The cumulative effects of the under/over collection of these costs are recorded in Alliant Energy's, IPL's and WPL's Consolidated Balance Sheets as current regulatory assets or current regulatory liabilities until they are reflected in future billings to customers.

In 2007, WPL had a gas performance incentive that included a sharing mechanism whereby 35% of gains or losses relative to current commodity prices and benchmarks were retained by WPL, with 65% refunded to or recovered from customers. Effective Nov. 1, 2007, this gas performance incentive sharing mechanism was terminated. WPL's gas performance incentive sharing mechanism resulted in gains of $5 million recorded as "Gas operating revenues" in Alliant Energy's and WPL's Consolidated Statements of Income in 2007.

Refer to Notes 1(b) and 2 for additional information regarding these utility cost recovery mechanisms.

Black Hills Corp.

Black Hills

Regulation and Rates

State Regulation

Our utilities are subject to the jurisdiction of the public utilities commissions in the states where they operate. The commissions oversee services and facilities, rates and charges, accounting, valuation of property, depreciation rates and various other matters. Certain commissions also have jurisdiction over the issuance of debt or securities, and the creation of liens on property located in their state to secure bonds or other securities.

We distribute natural gas in five states. All of our regulated Gas Utilities, including Cheyenne Light, have gas cost adjustments that allow us to pass the prudently-incurred cost of gas through to the customer. In Kansas and Nebraska, we are also allowed to recover the portion of uncollectible accounts related to gas costs through the gas cost adjustments. In Kansas, we have a weather normalization tariff that provides a pass-through mechanism for weather margin variability that occurs from the level used to establish base rates to be paid by the customer. In Kansas, we also have tariffs that provide for more timely recovery for certain capital expenditures and fluctuations in property taxes. In Nebraska, legislation was passed in 2009 to authorize the NPSC to provide for more timely recovery from our customers for certain capital expenditures between rate cases.

We produce and distribute power in four states. The regulatory provisions for recovering the costs to produce electricity vary by state. In South Dakota, Wyoming, Colorado and Montana, we have cost adjustment mechanisms for our regulated Electric Utilities that serve a purpose similar to the cost adjustment mechanisms in our regulated Gas Utilities. At Cheyenne Light, our pass-through mechanism relating to transmission, fuel and purchased power costs is subject to a $1.0 million threshold: we collect or refund 95% of the increase or decrease that exceeds the $1.0 million threshold, and we absorb the increase or retain the savings for changes above or below the threshold.

In South Dakota, we have three adjustment mechanisms: transmission, steam plant fuel (coal) and conditional energy cost adjustment. The transmission and steam plant fuel adjustment clauses requires an annual adjustment to rates for actual costs, therefore any savings or increased costs are passed on to the South Dakota customers. The conditional energy cost adjustment relates to purchased power and natural gas used to generate electricity. These costs are subject to calendar year $2.0 million and $1.0 million thresholds where Black Hills Power absorbs the first $2.0 million of increased costs or retains the first $1.0 million in savings. Beyond these thresholds, costs or savings are passed on to South Dakota customers through annual calendar-year filings.

In Colorado, we have a cost adjustment for increases or decreases in purchased power and fuel costs and a transmission cost adjustment. The cost adjustment clause provides for the direct recovery of increased purchased power and fuel costs or the issuance of credits for decreases in purchased power and fuel costs. The transmission cost adjustment is a rider to the customer's bill which allows the utility to earn an authorized return on new transmission investment and recovery of operations and maintenance costs related to transmission.

The above mechanisms allow the utilities to collect, or refund, the difference between the costs of commodities imbedded in our base rates and the actual costs of the commodities without filing a general rate case. In some instances, such as the transmission cost adjustment in Colorado, the utility has the opportunity to earn its authorized return on new capital investment.

Certain states where we conduct electric utility operations have adopted renewable energy portfolio standards that require or encourage our regulated Electric Utilities to source, by a certain future date, a minimum percentage of the electricity delivered to customers from renewable energy generation facilities. At December 31, 2009, we were subject to the following renewable energy portfolio standards or objectives:

- South Dakota. South Dakota has adopted a renewable portfolio objective that encourages utilities to generate, or cause to be generated, at least 10% of their retail electricity supply from renewable energy sources by 2015. Absent a specific renewable energy mandate in South Dakota, our current strategy is to prudently incorporate renewable energy into our resource supply, seeking to minimize associated rate increases for our utility customers.

- Montana. Montana established a renewable portfolio standard that requires Black Hills Power to obtain a percentage of its retail electric sales in Montana from eligible renewable resources according to the following schedule: (i) 5% for compliance years 2008-2009; (ii) 10% for compliance years 2010-2014; and (iii) 15% for compliance year 2015 and thereafter. Utilities can meet this standard by entering into long-term purchase contracts for electricity bundled with renewable-energy credits, by purchasing the renewable-energy credits separately, or by a combination of both. The law includes cost caps that limit the additional cost utilities must pay for renewable energy and allows cost recovery from ratepayers for contracts pre-approved by the MTPSC. We are currently in compliance with applicable standards.

- Colorado. The Colorado legislature adopted a renewable energy standard that requires our Colorado Electric subsidiary to generate, or cause to be generated, electricity from renewable energy sources equaling: (i) at least 10% of its retail sales by 2010; (ii) 15% of retail sales by 2015; and (iii) 20% of retail sales by 2020. Of these amounts, 4% must be generated from solar renewable resources with one-half of the solar resources being located at customer facilities. The law limits the net annual incremental retail rate impact from these renewable resource acquisitions (as compared to non-renewable resources) to 2% and encourages the CPUC to consider earlier and timely cost recovery for utility investment in renewable resources, including the use of a forward rider mechanism. We currently expect to be in compliance with the 2010 standards.

Wyoming is also exploring the implementation of renewable energy portfolio standards. Mandatory portfolio standards have increased, and may continue to increase the power supply costs of our electric operations. Although we will seek to recover these higher costs in rates, we can provide no assurance that we will be able to secure full recovery of the costs we pay to be in compliance with standards or objectives.

Incentive Regulation (cont.): energy conservation targets. To date, the PUC has not issued a final order in this case.

Settlements: The settlement process has been used extensively in Colorado. Since 1986 a series of settlements were approved regarding Fort St. Vrain and PSR's rates. The initial settlement provided: for Fort St. Vrain to be removed from PSR's base rates; for the unit to be treated as an independent power producer; and, for the termination of numerous legal proceedings. A 1988 settlement provided for a two-year rate case moratorium and a revenue sharing mechanism for earnings above targeted levels. In 1991 the PUC adopted settlements which, among other things, established PSR's prospective rates and provided for recovery of costs associated with the immediate decommissioning/dismantlement of Fort St. Vrain. The revenue requirement phase of USW's most recent rate case was also resolved though a negotiated agreement.

Court Actions: Commission decisions may be appealed to a state District Court and then to the Colorado Supreme Court. Judges are initially appointed by the Governor for two years, but must gain voter approval to continue in office. In February 1991, the Douglas County District Court reversed a December 1989 PUC decision, which had approved PSR's upgrade of an existing above-ground transmission line from 115 kv to 230 kv. The Court ruled that it was necessary for the PUC to promulgate rules and regulations in order to inform participants what factors would be considered relevant in making its determination. The PUC and PSR have appealed the District Court's ruling to the state's Supreme Court.

Legislation: The Colorado General Assembly meets annually beginning on the Wednesday after the first Tuesday in January. In 1989, House Bill 1104 was enacted. This bill gives energy companies authority to seek PUC approval to enter into a contract with a customer when a competitive alternative is available to the customer. In 1990, Senate Bill 69 reinstated subsidized life-line telephone service. The bill requires the state's telecommunications companies to bear the costs of administering the service. A legislative "Sunset Review" is to be completed prior to the PUC's July 1, 1993 termination date.

ENERGY ISSUES

Integrated Resource Planning: In November 1990, the PUC approved a demand-side management cost adjustment (DSMCA) for PSR which is designed to provide for recovery of costs associated with a 100-mw DSM bidding program. The DSMCA provides for relevant DSM investment to be rate based and recovered over seven years, for program costs not included in rate base to be expensed, and for the implementation of a DSM incentive mechanism. The complex DSM incentive formula recognizes program costs as compared to the cost of alternative supply-side capacity and weighs the projected duration and performance of the DSM program. The base incentive is 5% of the estimated monthly cost per kw of alternative supply-side capacity multiplied by the capacity associated with DSM programs in effect. The alternative supply-side capacity cost was fixed at $14/kw per month. The DSM incentive is to increase or decrease 1% for each year the weighted average program bid payment cost ($/kw) is $5 below, or .5 above, $240. The incentive increases or decreases 10% for each year the weighted average project life is greater or lower than 13 years.

In December 1990, the PUC requested comments on a draft policy statement regarding DSM, resource planning, and the decoupling of utilities' earnings from sales. The PUC stated that it "is dedicated to the goal of minimizing the total societal costs of energy services by improving long range planning and by identifying opportunities for additional savings." The Commission indicated that it would examine both the relationship between utility profitability and sales and recommendations for decoupling this relationship. Specifically, the PUC requested comments on an electric revenue adjustment mechanism. The draft policy statement supported renewable energy resources and elicited suggestions on how to successfully integrate cost-effective renewables into the supply mix.

A July 1991 PUC decision for PSR provided for the creation of separate dockets to address: (1) the decoupling of PSR's revenues from its sales, and regulatory incentives to encourage DSM programs; (2) the institution of a collaborative process to design and implement DSM programs; (3) an integrated resource planning (IRP) rulemaking; and, (4) a low income assistance docket. According to an agreement among the participants in the rate proceeding, the IRP rulemaking should resolve such issues as: the integration of DSM into resource planning; the evaluation of environmental externalities and whether and how they are taken into account in resource selection; the procedures, if any, to be used for the review of PSR's planning assumptions, forecasts, and methodologies; the appropriate methodology for determination of avoided costs of supply-side resources and appropriate discount rates; and, the objectives of IRP. A joint hearing will be conducted in June 1992 in the revenue decoupling and regulatory incentives docket and the IRP docket, with the results of these proceedings, to supersede the PUC policy previously described. PUC decisions are likely in August 1992.

In February 1991 the PUC ruled that electric utilities must provide potential line extension customers with data that compares the cost of the line extension to that of a photovoltaic system. This rule is subject to review during 1992.

Adjustment Clauses:

An Electric Cost Adjustment (ECA) is included in PSR's electric tariffs. The ECA provides for the recovery of costs associated with fuel and purchased power, changes in system line and transmission losses, and differences between actual and test period system fuel mixes. PSR is authorized to recover costs associated with purchasing power from cogenerators and independent producers through the ECA. The ECA is adjusted monthly and utilizes a test period based upon the preceding month's actual costs. Over- or under-collections are applied to customers bills in the second succeeding month. The proposed monthly adjustments are filed with the PUC for approval. In addition, the PUC Staff audits the operation of the clause and hearings are held on an annual basis.

NOTE: This bill has been prepared for the signature of the appropriate legislative officers and the Governor. To determine whether the Governor has signed the bill or taken other action on it, please consult the legislative status sheet, the legislative history, or the Session Laws.

An Act

HOUSE BILL 07-1037

BY REPRESENTATIVE(S) Levy, Borodkin, Buescher, Carroll M., Fischer, Frangas, Green, Hodge, Jahn, Kefalas, Kerr A., Labuda, McGihon, Merrifield, Peniston, Primavera, Rice, Solano, and Todd;
also SENATOR(S) Fitz-Gerald, Boyd, Gordon, Groff, Romer, Schwartz, Shaffer, Tochtrop, Tupa, Williams, and Windels.

CONCERNING MEASURES TO PROMOTE ENERGY EFFICIENCY, AND MAKING AN APPROPRIATION THEREFOR.

Be it enacted by the General Assembly of the State of Colorado:

SECTION 1. 40-1-102 (5) and (6), Colorado Revised Statutes, are amended, and the said 40-1-102 is further amended BY THE ADDITION OF THE FOLLOWING NEW SUBSECTIONS, to read:

40-1-102. Definitions. As used in articles 1 to 7 of this title, unless the context otherwise requires:

(5) (a) ~~"Person" means any individual, firm, partnership, corporation, company, association, joint stock association, and other legal entity.~~ "COST-EFFECTIVE", WITH REFERENCE TO A NATURAL GAS OR ELECTRIC DEMAND SIDE MANAGEMENT PROGRAM OR RELATED MEASURE, MEANS HAVING A BENEFIT-COST RATIO GREATER THAN ONE.

Capital letters indicate new material added to existing statutes; dashes through words indicate deletions from existing statutes and such material not part of act.

(b) IN CALCULATING THE BENEFIT-COST RATIO, THE BENEFITS SHALL INCLUDE, BUT ARE NOT LIMITED TO, THE FOLLOWING, AS APPLICABLE:

(I) THE UTILITY'S AVOIDED GENERATION, TRANSMISSION, DISTRIBUTION, CAPACITY, AND ENERGY COSTS;

(II) THE VALUATION OF AVOIDED EMISSIONS; AND

(III) NONENERGY BENEFITS AS DETERMINED BY THE COMMISSION.

(c) IN CALCULATING THE BENEFIT-COST RATIO, THE COSTS SHALL INCLUDE, BUT ARE NOT LIMITED TO, UTILITY AND PARTICIPANT EXPENDITURES FOR THE FOLLOWING, AS APPLICABLE:

(I) PROGRAM DESIGN, ADMINISTRATION, EVALUATION, ADVERTISING, AND PROMOTION;

(II) CUSTOMER EDUCATION;

(III) INCENTIVES AND DISCOUNTS;

(IV) CAPITAL COSTS; AND

(V) OPERATION AND MAINTENANCE EXPENSES.

(6) ~~"Renewable energy" means useful electrical, thermal, or mechanical energy converted directly or indirectly from resources of continuous energy flow or that are perpetually replenished and whose utilization is sustainable indefinitely. The term includes, without limitation, sunlight, the wind, geothermal energy, hydrodynamic forces, and organic matter available on a renewable basis such as forest residues, agricultural crops and wastes, wood and wood wastes, animal wastes, livestock operation residue, aquatic plants, and municipal wastes.~~ "DEMAND-SIDE MANAGEMENT PROGRAMS" OR "DSM PROGRAMS" MEANS ENERGY EFFICIENCY, CONSERVATION, LOAD MANAGEMENT, AND DEMAND RESPONSE PROGRAMS OR ANY COMBINATION OF THESE PROGRAMS.

(7) "EDUCATION PROGRAM" MEANS A PROGRAM, INCLUDING BUT NOT LIMITED TO AN ENERGY AUDIT, THAT CONTRIBUTES INDIRECTLY TO A

COST-EFFECTIVE DEMAND-SIDE MANAGEMENT PROGRAM. EDUCATION PROGRAMS SHALL NOT BE SUBJECT TO INDEPENDENT COST-EFFECTIVENESS REQUIREMENTS.

(8) "FULL SERVICE CUSTOMER" MEANS A RESIDENTIAL OR COMMERCIAL CUSTOMER THAT PURCHASES NATURAL GAS OR ELECTRIC SUPPLY FROM AN INVESTOR-OWNED UTILITY.

(9) "NET PRESENT VALUE OF REVENUE REQUIREMENTS" MEANS THE CURRENT WORTH OF THE EXPECTED STREAM OF FUTURE REVENUE REQUIREMENTS ASSOCIATED WITH A PARTICULAR RESOURCE PORTFOLIO, EXPRESSED IN DOLLARS IN THE YEAR THE PLAN IS FILED. TO DETERMINE THE CURRENT WORTH OF THE EXPECTED STREAM OF FUTURE REVENUE REQUIREMENTS, A DISCOUNT RATE AT THE UTILITY'S WEIGHTED AVERAGE COST OF CAPITAL SHALL BE APPLIED TO THE EXPECTED STREAM OF FUTURE REVENUE REQUIREMENTS.

(10) "PERSON" MEANS ANY INDIVIDUAL, FIRM, PARTNERSHIP, CORPORATION, COMPANY, ASSOCIATION, JOINT STOCK ASSOCIATION, AND OTHER LEGAL ENTITY.

(11) "RENEWABLE ENERGY" MEANS USEFUL ELECTRICAL, THERMAL, OR MECHANICAL ENERGY CONVERTED DIRECTLY OR INDIRECTLY FROM RESOURCES OF CONTINUOUS ENERGY FLOW OR THAT ARE PERPETUALLY REPLENISHED AND WHOSE UTILIZATION IS SUSTAINABLE INDEFINITELY. THE TERM INCLUDES, WITHOUT LIMITATION, SUNLIGHT, THE WIND, GEOTHERMAL ENERGY, HYDRODYNAMIC FORCES, AND ORGANIC MATTER AVAILABLE ON A RENEWABLE BASIS SUCH AS FOREST RESIDUES, AGRICULTURAL CROPS AND WASTES, WOOD AND WOOD WASTES, ANIMAL WASTES, LIVESTOCK OPERATION RESIDUE, AQUATIC PLANTS, AND MUNICIPAL WASTES.

SECTION 2. 40-3.2-101, Colorado Revised Statutes, is amended to read:

40-3.2-101. Legislative declaration. THE GENERAL ASSEMBLY HEREBY FINDS, DETERMINES, AND DECLARES THAT COST-EFFECTIVE NATURAL GAS AND ELECTRICITY DEMAND-SIDE MANAGEMENT PROGRAMS WILL SAVE MONEY FOR CONSUMERS AND UTILITIES AND PROTECT COLORADO'S ENVIRONMENT. The general assembly ~~hereby~~ FURTHER finds, determines, and declares that providing ~~a~~ funding ~~mechanism~~ MECHANISMS to encourage Colorado's public utilities to reduce emissions or air pollutants ~~is a matter~~ AND TO INCREASE ENERGY EFFICIENCY ARE MATTERS of statewide concern, ~~The general assembly further finds~~ AND that the public interest is served by providing such funding ~~mechanism~~ MECHANISMS. Such ~~reduction~~ EFFORTS will result in an improvement in the quality of life and health of Colorado citizens and an increase in the attractiveness of Colorado as a place to live and conduct business.

SECTION 3. Article 3.2 of title 40, Colorado Revised Statutes, is amended BY THE ADDITION OF THE FOLLOWING NEW SECTIONS to read:

40-3.2-103. Gas distribution utility demand-side management programs - rules - recovery of costs. (1) ON OR BEFORE SEPTEMBER 30, 2007, THE COMMISSION SHALL COMMENCE A RULE-MAKING PROCEEDING, AS DESCRIBED IN SUBSECTION (2) OF THIS SECTION, TO DEVELOP EXPENDITURE AND NATURAL GAS SAVINGS TARGETS, FUNDING AND COST-RECOVERY MECHANISMS, AND A FINANCIAL BONUS STRUCTURE FOR DEMAND-SIDE MANAGEMENT PROGRAMS IMPLEMENTED BY AN INVESTOR-OWNED GAS DISTRIBUTION UTILITY, ALSO REFERRED TO IN THIS SECTION AS A "GAS UTILITY".

(2) AS PART OF THE RULE-MAKING PROCEEDING REQUIRED BY SUBSECTION (1) OF THIS SECTION, THE COMMISSION SHALL:

(a) ADOPT DSM PROGRAM EXPENDITURE TARGETS EQUAL TO AT LEAST ONE-HALF OF ONE PERCENT OF A NATURAL GAS UTILITY'S REVENUES FROM ITS FULL SERVICE CUSTOMERS IN THE YEAR PRIOR TO SETTING SUCH TARGETS;

(b) ESTABLISH DSM PROGRAM SAVINGS TARGETS THAT ARE COMMENSURATE WITH PROGRAM EXPENDITURES AND EXPRESSED IN TERMS OF AN AMOUNT OF GAS SAVED PER UNIT OF PROGRAM EXPENDITURES;

(c) (I) ADOPT PROCEDURES FOR ALLOWING GAS UTILITIES TO RECOVER THEIR PRUDENTLY INCURRED COSTS OF DSM PROGRAMS WITHOUT HAVING TO FILE A RATE CASE. SUCH COSTS SHALL INCLUDE, BUT ARE NOT LIMITED TO, FACILITY INVESTMENTS; REBATES; INTEREST RATE BUYDOWNS; INCREMENTAL LABOR COSTS, EMPLOYEE BENEFITS, CARRYING COSTS, AND EMPLOYEE-RELATED ADMINISTRATIVE COSTS; AND OTHER ADMINISTRATIVE

COSTS. ALL SUCH COSTS SHALL BE RECOVERED THROUGH A COST ADJUSTMENT MECHANISM THAT IS SET ON AN ANNUAL BASIS, OR MORE FREQUENTLY IF DEEMED APPROPRIATE.

(II) COST ADJUSTMENT PROCEDURES SHALL GIVE GAS UTILITIES THE OPTION OF OBTAINING COST RECOVERY EITHER THROUGH EXPENSING DSM PROGRAM EXPENDITURES OR ADDING THEM TO BASE RATES, WITH AN AMORTIZATION PERIOD TO BE DETERMINED BY THE COMMISSION. IN ADDITION, SUCH PROCEDURES SHALL PROVIDE THAT COST RECOVERY FOR PROGRAMS DIRECTED AT RESIDENTIAL CUSTOMERS ARE TO BE COLLECTED FROM RESIDENTIAL CUSTOMERS ONLY AND THAT COST RECOVERY FOR PROGRAMS DIRECTED AT NONRESIDENTIAL CUSTOMERS ARE TO BE COLLECTED FROM NONRESIDENTIAL CUSTOMERS ONLY.

(d) ADOPT A BONUS STRUCTURE TO REWARD GAS UTILITIES FOR INVESTMENTS IN COST-EFFECTIVE DSM PROGRAMS. FOR EACH YEAR OF OPERATION, THE BONUS SHALL BE CAPPED AT TWENTY-FIVE PERCENT OF THE EXPENDITURES OR TWENTY PERCENT OF THE NET ECONOMIC BENEFITS OF THE DSM PROGRAMS, WHICHEVER AMOUNT IS LOWER. THE AMOUNT OF THE BONUS AWARDED EACH YEAR SHALL BE DETERMINED BASED ON THE EXTENT TO WHICH THE GAS UTILITY HAS ACHIEVED THE TARGETS ESTABLISHED BY THE COMMISSION IN ACCORDANCE WITH PARAGRAPHS (a) AND (b) OF THIS SUBSECTION (2). THE BONUS SHALL NOT COUNT AGAINST A GAS UTILITY'S AUTHORIZED RATE OF RETURN OR BE CONSIDERED IN RATE PROCEEDINGS.

(e) CONSIDER THE FACT THAT IMPLEMENTING THE NEW DSM PROGRAMS MAY REQUIRE A PHASE-IN PERIOD BEFORE A GAS UTILITY IS ABLE TO ACHIEVE THE FUNDING LEVEL DETERMINED BY THE COMMISSION PURSUANT TO PARAGRAPH (a) OF THIS SUBSECTION (2). A GAS UTILITY THAT IMPLEMENTS A NEW DSM PROGRAM IN PHASES SHALL BE ELIGIBLE TO RECEIVE A BONUS UNDER THE BONUS STRUCTURE ADOPTED PURSUANT TO PARAGRAPH (d) OF THIS SUBSECTION (2) DURING ITS PHASE-IN PERIOD.

(f) NOT ADOPT ANY MEASURE AUTHORIZING A FINANCIAL PENALTY AGAINST A GAS UTILITY THAT FAILS TO MEET THE TARGETS IN ANY PARTICULAR YEAR.

(3) WITHIN TWELVE MONTHS AFTER THE COMPLETION OF THE RULE-MAKING REQUIRED BY SUBSECTION (1) OF THIS SECTION, EACH GAS UTILITY SHALL:

(a) DEVELOP AND BEGIN IMPLEMENTING A SET OF COST-EFFECTIVE DSM PROGRAMS FOR ITS FULL SERVICE CUSTOMERS. SUCH PROGRAMS SHALL BE OF THE GAS UTILITY'S CHOOSING, TAKING INTO ACCOUNT THE CHARACTERISTICS OF THE GAS UTILITY AND ITS CUSTOMERS. ONE OR MORE PROGRAMS MAY BE TARGETED TO LOW-INCOME CUSTOMERS AND, IF SO, MAY BE PROVIDED DIRECTLY BY THE GAS UTILITY OR INDIRECTLY THROUGH FINANCIAL SUPPORT OF CONSERVATION PROGRAMS FOR LOW-INCOME HOUSEHOLDS ADMINISTERED BY THE STATE.

(b) IN IMPLEMENTING DSM PROGRAMS, USE REASONABLE EFFORTS TO MAXIMIZE ENERGY SAVINGS CONSISTENT WITH THE ANNUAL ENERGY EFFICIENCY BUDGET.

(4) IN IMPLEMENTING DSM PROGRAMS, GAS UTILITIES MAY SPEND A DISPROPORTIONATE SHARE OF TOTAL EXPENDITURES ON ONE OR MORE CLASSES OF CUSTOMERS.

(5) THE COMMISSION SHALL AUTHORIZE EACH GAS UTILITY TO RECOVER MONEYS SPENT FOR EDUCATION PROGRAMS, IMPACT AND PROCESS EVALUATIONS, AND PROGRAM PLANNING RELATED TO NATURAL GAS DSM PROGRAMS OFFERED BY THE GAS UTILITY WITHOUT HAVING TO SHOW THAT SUCH EXPENDITURES, ON AN INDEPENDENT BASIS, ARE COST-EFFECTIVE. THE COMMISSION MAY LIMIT THE AMOUNT SPENT FOR THESE ACTIVITIES.

(6) (a) GAS UTILITIES SHALL SUBMIT ANNUAL REPORTS TO THE COMMISSION, AS DETERMINED BY THE COMMISSION BY RULE. THE ANNUAL REPORT SHALL DESCRIBE THE GAS UTILITY'S DSM PROGRAMS AND SHALL DOCUMENT PROGRAM EXPENDITURES, ENERGY SAVINGS IMPACTS AND THE TECHNIQUES USED TO ESTIMATE THESE IMPACTS, THE ESTIMATED COST-EFFECTIVENESS OF PROGRAM EXPENDITURES, AND ANY OTHER INFORMATION THE COMMISSION MAY REQUIRE.

(b) THE COMMISSION SHALL REVIEW EACH REPORT SUBMITTED PURSUANT TO PARAGRAPH (a) OF THIS SUBSECTION (6) AND SHALL DETERMINE THE LEVEL OF BONUS, IF ANY, THAT THE GAS UTILITY IS ELIGIBLE TO COLLECT ON THE BASIS OF THE INFORMATION INCLUDED IN THE REPORT. THE COMMISSION'S DETERMINATION SHALL BE MADE WITHIN THREE MONTHS AFTER RECEIVING THE REPORT. ANY SUCH BONUS SHALL BE AUTHORIZED AS A SUPPLEMENT TO THE COST ADJUSTMENT MECHANISM OR ALTERNATIVE MECHANISM APPROVED BY THE COMMISSION AND SHALL BE APPLIED OVER

A TWELVE-MONTH PERIOD AFTER APPROVAL OF THE BONUS.

(7) GAS UTILITIES MAY CONTINUE DSM PROGRAMS THAT WERE IN EXISTENCE ON OR BEFORE THE EFFECTIVE DATE OF THIS SUBSECTION (7), AND SHALL NOT BE REQUIRED TO OBTAIN APPROVAL FROM THE COMMISSION FOR SUCH PROGRAMS.

(8) THIS SECTION SHALL NOT BE CONSTRUED TO EXTEND THE COMMISSION'S AUTHORITY TO ANY NONREGULATED UTILITY BUSINESSES OR AFFILIATES OF A GAS UTILITY.

40-3.2-104. Electricity utility demand-side management programs - rules - annual report. (1) IT IS THE POLICY OF THE STATE OF COLORADO THAT A PRIMARY GOAL OF ELECTRIC UTILITY LEAST-COST RESOURCE PLANNING IS TO MINIMIZE THE NET PRESENT VALUE OF REVENUE REQUIREMENTS. THE COMMISSION MAY ADOPT RULES AS NECESSARY TO IMPLEMENT THIS POLICY.

(2) THE COMMISSION SHALL ESTABLISH ENERGY SAVINGS AND PEAK DEMAND REDUCTION GOALS TO BE ACHIEVED BY AN INVESTOR-OWNED ELECTRIC UTILITY, TAKING INTO ACCOUNT THE UTILITY'S COST-EFFECTIVE DSM POTENTIAL, THE NEED FOR ELECTRICITY RESOURCES, THE BENEFITS OF DSM INVESTMENTS, AND OTHER FACTORS AS DETERMINED BY THE COMMISSION. THE ENERGY SAVINGS AND PEAK DEMAND REDUCTION GOALS SHALL BE AT LEAST FIVE PERCENT OF THE UTILITY'S RETAIL SYSTEM PEAK DEMAND MEASURED IN MEGAWATTS IN THE BASE YEAR AND AT LEAST FIVE PERCENT OF THE UTILITY'S RETAIL ENERGY SALES MEASURED IN MEGAWATT-HOURS IN THE BASE YEAR. THE BASE YEAR SHALL BE 2006. THE GOALS SHALL BE MET IN 2018, COUNTING SAVINGS IN 2018 FROM DSM MEASURES INSTALLED STARTING IN 2006. THE COMMISSION MAY ESTABLISH INTERIM GOALS AND MAY REVISE THE GOALS AS IT DEEMS APPROPRIATE.

(3) THE COMMISSION SHALL PERMIT ELECTRIC UTILITIES TO IMPLEMENT COST-EFFECTIVE ELECTRICITY DSM PROGRAMS TO REDUCE THE NEED FOR ADDITIONAL RESOURCES THAT WOULD OTHERWISE BE MET THROUGH A COMPETITIVE ACQUISITION PROCESS.

(4) THE COMMISSION SHALL ENSURE THAT UTILITIES DEVELOP AND IMPLEMENT DSM PROGRAMS THAT GIVE ALL CLASSES OF CUSTOMERS AN OPPORTUNITY TO PARTICIPATE AND SHALL GIVE DUE CONSIDERATION TO THE

IMPACT OF DSM PROGRAMS ON NONPARTICIPANTS AND ON LOW-INCOME CUSTOMERS.

(5) THE COMMISSION SHALL ALLOW AN OPPORTUNITY FOR A UTILITY'S INVESTMENTS IN COST-EFFECTIVE DSM PROGRAMS TO BE MORE PROFITABLE TO THE UTILITY THAN ANY OTHER UTILITY INVESTMENT THAT IS NOT ALREADY SUBJECT TO SPECIAL INCENTIVES. IN COMPLYING WITH THIS SUBSECTION (5), THE COMMISSION SHALL CONSIDER, WITHOUT LIMITATION, THE FOLLOWING INCENTIVE MECHANISMS, WHICH SHALL TAKE INTO CONSIDERATION THE PERFORMANCE OF THE DSM PROGRAM:

(a) AN INCENTIVE TO ALLOW A RATE OF RETURN ON DSM INVESTMENTS THAT IS HIGHER THAN THE UTILITY'S RATE OF RETURN ON OTHER INVESTMENTS;

(b) AN INCENTIVE TO ALLOW THE UTILITY TO ACCELERATE THE DEPRECIATION OR AMORTIZATION PERIOD FOR DSM INVESTMENTS;

(c) AN INCENTIVE TO ALLOW THE UTILITY TO RETAIN A PORTION OF THE NET ECONOMIC BENEFITS ASSOCIATED WITH A DSM PROGRAM FOR ITS SHAREHOLDERS;

(d) AN INCENTIVE TO ALLOW THE UTILITY TO COLLECT THE COSTS OF DSM PROGRAMS THROUGH A COST ADJUSTMENT CLAUSE;

(e) OTHER INCENTIVE MECHANISMS THAT THE COMMISSION DEEMS APPROPRIATE.

(6) EACH INVESTOR-OWNED ELECTRIC UTILITY SHALL SUBMIT AN ANNUAL REPORT TO THE COMMISSION DESCRIBING THE DSM PROGRAMS IMPLEMENTED BY THE ELECTRIC UTILITY IN THE PREVIOUS YEAR. THE REPORT SHALL DOCUMENT THE FOLLOWING:

(a) PROGRAM EXPENDITURES, INCLUDING INCENTIVE PAYMENTS;

(b) PEAK DEMAND AND ENERGY SAVINGS IMPACTS AND THE TECHNIQUES USED TO ESTIMATE THOSE IMPACTS;

(c) AVOIDED COSTS AND THE TECHNIQUES USED TO ESTIMATE THOSE COSTS;

(d) THE ESTIMATED COST-EFFECTIVENESS OF THE DSM PROGRAMS;

(e) THE NET ECONOMIC BENEFITS OF THE DSM PROGRAMS; AND

(f) ANY OTHER INFORMATION REQUIRED BY THE COMMISSION.

40-3.2-105. Reporting requirement. BY APRIL 30, 2009, AND BY EACH APRIL 30 THEREAFTER, THE COMMISSION SHALL SUBMIT A REPORT TO THE BUSINESS, LABOR, AND TECHNOLOGY COMMITTEE OF THE SENATE, OR ITS SUCCESSOR COMMITTEE, AND THE BUSINESS AFFAIRS AND LABOR OF THE HOUSE OF REPRESENTATIVES, OR ITS SUCCESSOR COMMITTEE, ON THE PROGRESS MADE BY INVESTOR-OWNED UTILITIES IN MEETING THEIR NATURAL GAS AND ELECTRICITY DEMAND-SIDE MANAGEMENT GOALS. THE REPORT SHALL INCLUDE ANY RECOMMENDED STATUTORY CHANGES THE COMMISSION DEEMS NECESSARY TO FURTHER THE INTENT OF SECTIONS 40-3.2-103 AND 40-3.2-104.

SECTION 4. Appropriation. (1) In addition to any other appropriation, there is hereby appropriated, out of any moneys in the public utilities commission fixed utilities fund created in section 40-2-114, Colorado Revised Statutes, not otherwise appropriated, to the department of regulatory agencies, for allocation to the executive director's office, for legal services, for the fiscal year beginning July 1, 2007, the sum of thirteen thousand five hundred fifty-four dollars ($13,554), or so much thereof as may be necessary, for the implementation of this act.

(2) In addition to any other appropriation, there is hereby appropriated, out of any moneys in the public utilities commission fixed utilities fund created in section 40-2-114, Colorado Revised Statutes, not otherwise appropriated, to the department of regulatory agencies, for allocation to the public utilities commission, for the fiscal year beginning July 1, 2007, one hundred seventy-eight thousand two hundred twenty-two dollars ($178,222) and 2.0 FTE, or so much thereof as may be necessary, for the implementation of this act.

(3) In addition to any other appropriation, there is hereby appropriated to the department of law, for the fiscal year beginning July 1, 2007, the sum of thirteen thousand five hundred fifty-four dollars ($13,554), or so much thereof as may be necessary, for the provision of legal services to the department of regulatory agencies related to the implementation of

this act. Said sum shall be from cash funds exempt received from the executive director's office out of the appropriation made in subsection (1) of this section.

SECTION 5. Safety clause. The general assembly hereby finds, determines, and declares that this act is necessary for the immediate preservation of the public peace, health, and safety.

Andrew Romanoff SPEAKER OF THE HOUSE OF REPRESENTATIVES	Joan Fitz-Gerald PRESIDENT OF THE SENATE
Marilyn Eddins CHIEF CLERK OF THE HOUSE OF REPRESENTATIVES	Karen Goldman SECRETARY OF THE SENATE

APPROVED____

Bill Ritter, Jr.
GOVERNOR OF THE STATE OF COLORADO

DTE Energy

PSCR A power supply cost recovery mechanism authorized by the MPSC that allows Detroit Edison to recover through rates its fuel, fuel-related and purchased power costs.

GCR A gas cost recovery mechanism authorized by the MPSC that allows MichCon to recover through rates its natural gas costs.

Strategy and Competition

Our strategy is to be the preferred provider of natural gas in Michigan. As a result of more efficient furnaces and appliances, and customer conservation due to high natural gas prices and economic conditions, we expect future sales volumes to decline. We expect to minimize the impacts of declines in usage through regulatory mechanisms we have requested in our current rate case, which will partially decouple our revenue levels from sales volumes. We continue to provide energy-related services that capitalize on our expertise, capabilities and efficient systems. We continue to focus on lowering our operating costs by improving operating efficiencies.

The MPSC has provided for an uncollectible expense tracking mechanism for MichCon since 2005. The uncollectible expense tracking mechanism enables MichCon to recover or refund 90 percent of the difference between the actual uncollectible expense for each year and $37 million after an annual reconciliation proceeding before the MPSC.

The January 2010 MPSC electric rate order provided for an uncollectible expense tracking mechanism for Detroit Edison. The uncollectible expense tracking mechanism enables Detroit Edison to recover or refund 80 percent of the difference between the actual uncollectible expense for each year and $66 million after an annual reconciliation proceeding before the MPSC.

Impact of Regulatory Decisions on Utility Operations

On January 11, 2010, the MPSC issued an order in Detroit Edison's January 26, 2009 rate case filing. The MPSC approved an annual revenue increase of $217 million or a 4.8% increase in Detroit Edison's annual revenue requirement for 2010. Included in the approved increase in revenues was a return on equity of 11% on an expected 49% equity and 51% debt permanent capital structure. Since the final rate relief ordered was less than the Company's self-implemented rate increase of $280 million effective on July 26, 2009, the MPSC ordered refunds for the period the self-implemented rates were in effect. Detroit Edison has recorded a refund liability of $27 million at December 31, 2009 representing the 2009 portion of the estimated refund due customers, including interest. The MPSC ordered Detroit Edison to file a refund plan by April 1, 2010.

Other key aspects of the MPSC order include the following:

- Continued progress toward correcting the existing rate structure to more accurately reflect the actual cost of providing service to business customers;
- Continued application of an adjustment mechanism for Electric Choice sales that reconciles actual customer choice sales with a base customer choice sales level of 1,586 GWh;
- Continued application of adjustment mechanisms to track expenses associated with restoration costs (storm and non-storm related expenses) and line clearance expenses. Annual reconciliations will be required using a base expense level of $117 million and $47 million, respectively. The change in base expense level was applied retroactive to the July 26, 2009 self-implementation date;
- Implementation of a pilot Revenue Decoupling Mechanism, that will compare actual (non-weather normalized) sales per customer with the base sales per customer level established in this case for the period February 1, 2010 to January 31, 2011; and
- Implementation of an Uncollectible Expense Tracking Mechanism, based on a $66 million expense level, with an 80/20 percent sharing of the expenses above or below the base amount. The Uncollectible Expenses Tracking Mechanism was implemented retroactive to the July 26, 2009 self-implementation date.

MichCon filed a general rate case on June 9, 2009 based on a 2008 historical test year. The filing with the MPSC requested a $193 million, or 11.5 percent average increase in MichCon's annual revenues for a 2010 projected test year. The requested $193 million increase in revenues is required to recover the increased costs associated with increased investments in net plant and working capital, an increase in the base level of the uncollectible expense tracking mechanism and the cost of natural gas theft primarily due to economic conditions in Michigan, sales reductions due to customer conservation and the trend of warmer weather on MichCon's market, and increasing operating costs, largely due to inflation. Pursuant to the October 2008 Michigan legislation, and the settlement in MichCon's last base gas sale case, MichCon self-implemented $170 million of its requested annual increase on January 1, 2010. This increase will remain in place until a final order is issued by the MPSC, which is expected in June 2010, subject to refund. See Note 12 of the Notes to Consolidated Financial Statements in Item 8 of this Report.

Outlook - Unfavorable national and regional economic trends have resulted in reduced demand for electricity in our service territory and continued high levels in our uncollectible accounts receivable. The magnitude of these trends will be driven by the impacts of the challenges in the domestic automotive industry and the timing and level of recovery in the national and regional economies. The January 2010 MPSC rate order, provided for an uncollectible expense tracking mechanism and a revenue decoupling mechanism will assist in mitigating these impacts.

The Electric and Gas utility businesses have risks in conjunction with the anticipated purchases of coal, natural gas, uranium, electricity, and base metals to meet their service obligations. However, the Company does not bear significant exposure to earnings risk as such changes are included in the form of PSCR and GCR regulatory rate-recovery mechanisms. In addition, changes in the price of natural gas can impact the valuation of lost and stolen gas, storage sales revenue and uncollectible expenses at the Gas Utility. Gas Utility manages its market price risk related to storage sales revenue primarily through the sale of long-term storage contracts. The Company has tracking mechanisms to mitigate a portion of losses related to uncollectible accounts receivable at MichCon and Detroit Edison. The Company is exposed to short-term cash flow or liquidity risk as a result of the time differential between actual cash settlements and regulatory rate recovery

Gas Utility

Contaminated Sites -- Prior to the construction of major interstate natural gas pipelines, gas for heating and other uses was manufactured locally from processes involving coal, coke or oil. Gas Utility owns, or previously owned, 15 such former MGP sites. Investigations have revealed contamination related to the by-products of gas manufacturing at each site. In addition to the MGP sites, the Company is also in the process of cleaning up other contaminated sites. Cleanup activities associated with these sites will be conducted over the next several years.

The MPSC has established a cost deferral and rate recovery mechanism for investigation and remediation costs incurred at former MGP sites. Accordingly, Gas Utility recognizes a liability and corresponding regulatory asset for estimated investigation and remediation costs at former MGP sites. During 2009, the Company spent approximately $1 million investigating and remediating these former MGP sites. As of December 31, 2009 and 2008, the Company had $36 million and $38 million, respectively, accrued for remediation.

Any significant change in assumptions, such as remediation techniques, nature and extent of contamination and regulatory requirements, could impact the estimate of remedial action costs for the sites and affect the Company's financial position and cash flows. However, the Company anticipates the cost deferral and rate recovery mechanism approved by the MPSC will prevent environmental costs from having a material adverse impact on our results of operations.

Edison International

Ed. Int'l

Cost-Recovery Rates

Cost-recovery mechanisms allow SCE to recover its costs, but do not allow a return or profit. These mechanisms are used to recover SCE's costs of fuel, purchased-power, demand-side management programs, nuclear decommissioning, public purpose programs, certain operation

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and maintenance expenses, and depreciation expense related to certain projects. Although the CPUC authorizes balancing account mechanisms for such costs to refund or recover any differences between forecasted and actual costs, under- or over-collections in these balancing accounts do impact cash flows and can build rapidly.

The CPUC also uses a mechanism known as a "balancing account" to eliminate the effect on earnings that differences in revenue resulting from actual and forecast electricity sales may have. Under this mechanism, the difference in revenue between actual and forecast electricity sales is recovered from or refunded to ratepayers and therefore does not impact SCE's earnings.

SCE's balancing account for fuel and power procurement-related costs is established under the Energy Resource Recovery Account ("ERRA") Mechanism. SCE files annual forecasts of the costs that it expects to incur during the following year and sets rates using forecasts. The CPUC has established a "trigger" mechanism for the ERRA balancing account that allows for a rate adjustment if the balancing account over-collection or under-collection exceeds 5% of SCE's prior year's generation revenue.

The majority of costs eligible for recovery through cost-recovery rates are subject to CPUC reasonableness reviews, and thus could negatively impact earnings and cash flows if found to be unreasonable and disallowed.

Energy Efficiency Shareholder Risk/Reward Incentive Mechanism

The CPUC has adopted an Energy Efficiency Risk/Reward Incentive Mechanism which allows for both financial incentives and economic penalties based on SCE's performance toward meeting goals set by the CPUC for energy efficiency. Under this mechanism, SCE has the opportunity to earn an incentive if it achieves 85% or more of its energy efficiency goals for the three year period. Economic penalties would be imposed in the event SCE achieves less than 65% of its goals. The mechanism allows for two annual progress payments, subject to holdback percentages, for progress towards meeting the goals and a third payment for final performance on the goals, which includes the payment of any holdbacks. SCE may retain the first and second progress payments as long as it meets a minimum of 65% of the goals. If SCE does not meet the 65% level, the amount of the progress payments and economic penalties would be deducted from future incentive payments. Both incentives and economic penalties for each three-year period are capped at $200 million.

In January 2009, the CPUC issued a new rulemaking intended to review the framework of the Energy Efficiency Risk/Reward Incentive Mechanism. The CPUC has yet to release a Decision on a new framework.

CDWR-Related Rates

As a result of the California energy crisis, in 2001 the California Department of Water Resources ("CDWR") entered into contracts to purchase power for sale at cost directly to SCE's retail customers and issued bonds to finance those power purchases. The CDWR's total statewide power charge and bond charge revenue requirements are allocated by the CPUC among the customers of the Investor-Owned Utilities. SCE bills and collects from its customers the costs of power purchased and sold by the CDWR, CDWR bond-related charges

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and direct access exit fees. The CDWR-related charges and a portion of direct access exit fees that are remitted directly to the CDWR are not recognized as electric utility revenue by SCE and therefore have no impact on SCE's earnings; however, they do impact customer rates.

Regulatory Proceedings

Cost of Capital Mechanism

In 2009, the CPUC granted SCE's request to forgo an expected 2010 cost of capital increase under the annual adjustment provision and extended SCE's existing capital structure and authorized rate of return of 11.5% through December 2012, absent any future potential annual adjustments. The revised mechanism will be subject to CPUC review in 2012 for the cost of capital set for 2013 and beyond.

Revenue Recognition

Electric utility revenue is recognized as electricity is delivered and includes amounts for services rendered but unbilled at the end of each reporting period. Rates charged to customers are based on CPUC-authorized and FERC-approved revenue requirements. CPUC rates are implemented upon final approval. FERC rates are often implemented on an interim basis at the time when the rate change is filed. Revenue collected prior to a final FERC approval decision is subject to refund.

SCE recognizes revenue from base rates and cost-recovery rates, and could potentially recognize revenue or incur penalties under incentive mechanisms. Base rate activities provide for recovery of operation and maintenance costs, capital-related carrying costs and a return or profit, on a forecast basis, as well as a return on certain capital-related projects approved through balancing account mechanisms, separate from the GRC process. **Cost-recovery rates provide for recovery for fuel, purchased power, demand-side management programs, nuclear decommissioning, public purpose programs, certain operation and maintenance expenses, and depreciation expense related to certain projects.** There is no markup for return or profit for cost-recovery expenses (revenue recognized under cost-recovery rates is equal to expenses incurred under these mechanisms), except for a return on certain capital-related balancing account projects.

The **CPUC-authorized decoupling revenue mechanism** allows for differences in revenue resulting from actual and forecast volumetric electricity sales to be collected from or refunded to ratepayers therefore such differences do not impact electric utility revenue. Differences between authorized operating costs included in SCE's base rate revenue requirement and actual operating costs incurred, other than pass-through costs, do not impact electric utility revenue, but have an impact on earnings

Power purchased by the CDWR related to long-term contracts it executed on behalf of SCE's customers between January 17, 2001 and December 31, 2002 is not considered a cost to SCE because SCE is acting as an agent for these transactions. Furthermore, amounts billed to ($1.8 billion in 2009, $2.2 billion in 2008 and $2.3 billion in 2007) and collected from SCE's customers for these power purchases, CDWR bond-related costs (effective November 15, 2002) and a portion of direct access exit fees (effective January 1, 2003) are being remitted to the CDWR and are not recognized as electric utility revenue by SCE.

The CPUC allows SCE to recover 90% of its environmental remediation costs at certain sites, representing $34 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. SCE expects to recover costs incurred at its remaining sites through customer rates. SCE has recorded a regulatory asset of $36 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

Empire District

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Fuel Adjustment Clauses. Typical fuel adjustment clauses permit the distribution to customers of changes in fuel costs without the need for a general rate proceeding. Fuel adjustment clauses are presently applicable to our retail electric sales in Missouri (effective September 1, 2008), Oklahoma and Kansas (effective January 1, 2006) and system wholesale kilowatt-hour sales under FERC jurisdiction. We have an Energy Cost Recovery Rider in Arkansas that adjusts for changing fuel and purchased power costs on an annual basis.

Gas Segment

General As a public utility, our gas segment operations are subject to the jurisdiction of the MPSC with respect to services and facilities, rates and charges, regulatory accounting, valuation of property, depreciation and various other matters. The MPSC also has jurisdiction over the creation of liens on property to secure bonds or other securities.

Purchased Gas Adjustment (PGA) The PGA clause allows EDG to recover from our customers, subject to routine regulatory review, the cost of purchased gas supplies, including costs associated with our use of natural gas financial instruments to hedge the purchase price of natural gas and related carrying costs. This PGA clause allows us to make rate changes periodically (up to four times) throughout the year in response to weather conditions and supply demands, rather than in one possibly extreme change per year.

The primary drivers of our electric operating expenses in any period are: (1) fuel and purchased power expense, (2) maintenance and repairs expense, including repairs following severe weather and plant outages, (3) taxes and (4) non-cash items such as depreciation and amortization expense. Historically, fuel and purchased power costs were the expense items that had the most significant impact on our net income. In our 2007 rate case, the Missouri Public Service Commission (MPSC) authorized a fuel adjustment clause for our Missouri customers effective September 1, 2008. The MPSC established a base rate for the recovery of fuel and purchased power expenses used to supply energy. The clause permits the distribution to customers of 95% of the changes in fuel and purchased power costs above or below the base. With the addition of the Missouri fuel adjustment mechanism, we now have a fuel cost recovery mechanism in all of our jurisdictions, which will significantly reduce the impact of fluctuating fuel and purchased power costs on our net income.

Fuel and Purchased Power

Electric Segment

Fuel and purchased power costs are recorded at the time the fuel is used, or the power purchased. This amount is adjusted to reflect regulatory treatment for our Missouri and Kansas fuel adjustment mechanisms discussed below.

The MPSC authorized a fuel adjustment clause (FAC) for our Missouri customers effective September 1, 2008. The MPSC established a base cost for the recovery of fuel and purchased power expenses used to supply energy. The FAC permits the distribution to customers of 95% of the changes in fuel and purchased power costs prudently incurred above or below the base cost. Off-system sales margins are also part of the recovery of fuel and purchased power costs. As a result, nearly all of the off-system sales margin flows back to the customer. Rates related to the fuel adjustment clause will be modified twice a year subject to the review and approval by the MPSC. In accordance with the ASC guidance for regulated operations, 95% of the difference between the actual costs of fuel and purchased power and the base cost of fuel and purchased power recovered from our customers is recorded as an adjustment to fuel and purchased power expense with a corresponding regulatory asset or regulatory liability. If the actual fuel and purchased power costs are higher or lower than the base fuel and purchased power costs billed to customers, 95% of these amounts will be recovered or refunded to our customers when the fuel adjustment clause is modified.

In our Kansas jurisdiction, the costs of fuel are recovered from customers through a fuel adjustment clause, based upon estimated fuel costs and purchased power. The adjustments are subject to audit and

Entergy Corp.

Entergy

Fuel and purchased power cost recovery

Entergy Arkansas, Entergy Gulf States Louisiana, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, and Entergy Texas are allowed to recover certain fuel and purchased power costs through fuel mechanisms included in electric and gas rates that are recorded as fuel cost recovery revenues. The difference between revenues collected and the current fuel and purchased power costs is recorded as "Deferred fuel costs" on the Utility operating companies' financial statements. The table below shows the amount of deferred fuel costs as of December 31, 2009 and 2008, that Entergy expects to recover (or return to customers) through fuel mechanisms, subject to subsequent regulatory review.

	2009	2008
	(In Millions)	
Entergy Arkansas	$122 8	$119.1
Entergy Gulf States Louisiana (a)	$57 8	$8.1
Entergy Louisiana (a)	$66.4	($23.6)
Entergy Mississippi	($72.9)	$5.0
Entergy New Orleans (a)	$8.1	$21.8
Entergy Texas	($102.7)	$21.2

(a) 2009 and 2008 include $100.1 million for Entergy Gulf States Louisiana and $68 million for Entergy Louisiana of fuel, purchased power, and capacity costs that are expected to be recovered over a period greater than twelve months. 2009 includes $4.1 million for Entergy New Orleans of fuel, purchased power, and capacity costs that are expected to be recovered over a period greater than twelve months.

Entergy Gulf States Louisiana made a $36.8 million adjustment to its deferred fuel costs in the fourth quarter 2009 relating to unrecovered nuclear fuel costs incurred since January 2008 that will now be recovered after a revision to the fuel adjustment clause methodology.

Retail Rate Regulation

General (Entergy Arkansas, Entergy Gulf States Louisiana, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, and Entergy Texas)

Each Utility operating company participates in retail rate proceedings on a consistent basis. The status of material retail rate proceedings is described in Note 2 to the financial statements. Certain aspects of the Utility operating companies' retail rate mechanisms are discussed below.

Entergy Arkansas

Fuel and Purchased Power Cost Recovery

Entergy Arkansas' rate schedules include an energy cost recovery rider to recover fuel and purchased energy costs in monthly bills. The rider utilizes prior calendar year energy costs and projected energy sales for the twelve-month period commencing on April 1 of each year to develop an energy cost rate, which is redetermined annually and includes a true-up adjustment reflecting the over-recovery or under-recovery, including carrying charges, of the energy cost for the prior calendar year. The energy cost recovery rider tariff also allows an interim rate request depending upon the level of over- or under-recovery of fuel and purchased energy costs. In December 2007, the APSC issued an order stating that Entergy Arkansas' energy cost recovery rider will remain in effect, and any future termination of the rider would be subject to eighteen months advance notice by the APSC, which would occur following notice and hearing. See Note 2 to the financial statements for a discussion of Entergy Arkansas' energy cost recovery rider proceedings before the APSC.

Storm Cost Recovery

See Note 2 to the financial statements for a discussion of proceedings regarding recovery of Entergy Arkansas' storm restoration costs.

Entergy Gulf States Louisiana

Fuel Recovery

Entergy Gulf States Louisiana's electric rates include a fuel adjustment clause designed to recover the cost of fuel and purchased power costs. The fuel adjustment clause contains a surcharge or credit for deferred fuel expense and related carrying charges arising from the monthly reconciliation of actual fuel costs incurred with fuel cost revenues billed to customers, including carrying charges.

To help stabilize electricity costs, Entergy Gulf States Louisiana received approval from the LPSC to hedge its exposure to natural gas price volatility through the use of financial instruments. Entergy Gulf States Louisiana hedges approximately one-third of the projected exposure to natural gas price changes for the gas used to serve its native electric load for all months of the year. The hedge quantity is reviewed on an annual basis.

Entergy Gulf States Louisiana's gas rates include a purchased gas adjustment clause based on estimated gas costs for the billing month adjusted by a surcharge or credit that arises from an annual reconciliation of fuel costs incurred with fuel cost revenues billed to customers, including carrying charges.

To help stabilize retail gas costs, Entergy Gulf States Louisiana received approval from the LPSC to hedge its exposure to natural gas price volatility for its gas purchased for resale through the use of financial instruments. Entergy Gulf States Louisiana hedges approximately one-half of the projected natural gas volumes used to serve its natural gas customers for November through March. The hedge quantity is reviewed on an annual basis.

Storm Cost Recovery

See Note 2 to the financial statements for a discussion of Entergy Gulf States Louisiana's filings to recover storm-related costs.

Entergy Louisiana

Fuel Recovery

Entergy Louisiana's rate schedules include a fuel adjustment clause designed to recover the cost of fuel and purchased power costs. The fuel adjustment clause contains a surcharge or credit for deferred fuel expense and related carrying charges arising from the monthly reconciliation of actual fuel costs incurred with fuel cost revenues billed to customers, including carrying charges.

In the Delaney vs. Entergy Louisiana proceeding, the LPSC ordered Entergy Louisiana, beginning with the May 2000 fuel adjustment clause filing, to re-price costs flowed through its fuel adjustment clause related to the Evangeline gas contract so that the price included for fuel adjustment clause recovery shall thereafter be at the rate of the Henry Hub first of the month cash market price (as reported by the publication *Inside FERC*) plus $0.24 per mmBtu for the month for which the fuel adjustment clause is calculated, irrespective of the actual cost for the Evangeline contract quantity reflected in that month's fuel adjustment clause.

To help stabilize electricity costs, Entergy Louisiana received approval from the LPSC in 2001 to hedge its exposure to natural gas price volatility through the use of financial instruments. Entergy Louisiana hedges approximately one-third of the projected exposure to natural gas price changes for the gas used to serve its native electric load for all months of the year. The hedge quantity is reviewed on an annual basis.

In September 2002, Entergy Louisiana settled a proceeding that concerned a contract entered into by Entergy Louisiana to purchase, through 2031, energy generated by a hydroelectric facility known as the Vidalia project. In the settlement, the LPSC approved Entergy Louisiana's proposed treatment of the regulatory effect of the benefit from a tax accounting election related to that project. In general, the settlement permits Entergy Louisiana to keep a portion of the tax benefit in exchange for bearing the risk associated with sustaining the tax treatment. The LPSC settlement divided the term of the Vidalia contract into two segments: 2002-2012 and 2013-2031. During the first eight years of the 2002-2012 segment, Entergy Louisiana agreed to credit rates by flowing through its fuel adjustment calculation $11 million each year, beginning monthly in October 2002. Entergy Louisiana must credit rates in this way and by this amount even if Entergy Louisiana is unable to sustain the tax deduction. Entergy Louisiana also must credit rates by $11 million each year for an additional two years unless either the tax accounting method elected is retroactively repealed or the IRS denies the entire deduction related to the tax accounting method. In addition, in accordance with an LPSC settlement, Entergy Louisiana credited rates in August 2007 by $11.8 million (including interest) as a result of a settlement with the IRS of the 2001 tax treatment of the Vidalia contract. Entergy Louisiana agreed to credit ratepayers additional amounts unless the tax accounting election was not sustained. During the years 2013-2031, Entergy Louisiana and its ratepayers would share the remaining benefits of this tax accounting election. Note 8 to the financial statements contains further discussion of the obligations related to the Vidalia project.

Storm Cost Recovery

See Note 2 to the financial statements for a discussion of Entergy Louisiana's filings to recover storm-related costs.

Entergy Mississippi

Fuel Recovery

Entergy Mississippi's rate schedules include energy cost recovery riders to recover fuel and purchased energy costs. The rider utilizes projected energy costs filed quarterly by Entergy Mississippi to develop an energy cost rate. The energy cost rate is redetermined each calendar quarter and includes a true-up adjustment reflecting the over-recovery or under-recovery of the energy cost as of the second quarter preceding the redetermination.

Power Management Rider

The MPSC approved the purchase of the Attala power plant in November 2005. In December 2005, the MPSC issued an order approving the investment cost recovery through its power management rider and limited the recovery to a period that begins with the closing date of the purchase and ends the earlier of the date costs are incorporated into base rates or December 31, 2006. As a consequence of the events surrounding Entergy Mississippi's ongoing efforts to recover storm restoration costs associated with Hurricane Katrina, in October 2006, the MPSC approved a revision to Entergy Mississippi's power management rider. The revision has the effect of allowing Entergy Mississippi to recover the annual ownership costs of the Attala plant until such time as a general rate case is filed.

To help stabilize electricity costs, Entergy Mississippi received approval from the MPSC to hedge its exposure to natural gas price volatility through the use of financial instruments. Entergy Mississippi hedges approximately one-half of the projected exposure to natural gas price changes for the gas used to serve its native electric load for all months of the year. The hedge quantity is reviewed on an annual basis.

Storm Cost Recovery

See Note 2 to the financial statements for a discussion of Entergy Mississippi's filings to recover storm-related costs.

Entergy New Orleans

Fuel Recovery

Entergy New Orleans' electric rate schedules include a fuel adjustment tariff designed to reflect no more than targeted fuel and purchased power costs, adjusted by a surcharge or credit for deferred fuel expense arising from the monthly reconciliation of actual fuel and purchased power costs incurred with fuel cost revenues billed to customers, including carrying charges. In June 2006, the City Council authorized the recovery of all Grand Gulf costs through Entergy New Orleans' fuel adjustment clause (a significant portion of Grand Gulf costs was previously recovered through base rates), and continued that authorization in approving the October 2006 formula rate plan filing settlement. Effective June 2009, the majority of Grand Gulf costs were realigned to base rates and are no longer flowed through the fuel adjustment clause.

Entergy New Orleans' gas rate schedules include a purchased gas adjustment to reflect estimated gas costs for the billing month, adjusted by a surcharge or credit similar to that included in the electric fuel adjustment clause, including carrying charges. In October 2005, the City Council approved modification of the current gas cost collection mechanism effective November 2005 in order to address concerns regarding its fluctuations, particularly during the winter heating season. The modifications are intended to minimize fluctuations in gas rates during the winter months.

To help stabilize retail gas costs, Entergy New Orleans received approval from the City Council to hedge its exposure to natural gas price volatility for its gas purchased for resale through the use of financial instruments. Entergy New Orleans hedges approximately one-half of the projected natural gas volumes used to serve its natural gas customers for November through March. The hedge quantity is reviewed on an annual basis.

Storm Cost Recovery

See Note 2 to the financial statements for a discussion of Entergy New Orleans' efforts to recover storm-related costs.

Entergy Texas

Fuel Recovery

Entergy Texas' rate schedules include a fixed fuel factor to recover fuel and purchased power costs, including carrying charges, not recovered in base rates. The fixed fuel factor formula was revised and approved by a PUCT order in August 2006. The new formula was implemented in September 2006. Under the new method, semi-annual revisions of the fixed fuel factor will continue to be made in March and September based on the expected change in the market price of natural gas over the next 12 months. The method also accounts for changes in resource mix and retail sales. To the extent actual costs vary from the fixed fuel factor, refunds or surcharges are required or permitted. The amounts collected under the fixed fuel factor through the start of retail open access are subject to fuel reconciliation proceedings before the PUCT. The PUCT fuel cost reviews are discussed in Note 2 to the financial statements.

2007 Rate Case

Entergy Texas made a rate filing in September 2007 with the PUCT requesting an annual rate increase totaling $107.5 million, including a base rate increase of $64.3 million and riders totaling $43.2 million. On December 16, 2008, Entergy Texas filed a term sheet that reflected a settlement agreement that included the PUCT Staff and the other active participants in the rate case. On December 19, 2008, the ALJs approved Entergy Texas' request to implement interim rates reflecting the agreement. The agreement includes a $46.7 million base rate increase, among other provisions. Under the ALJs' interim order, Entergy Texas implemented interim rates, subject to refund and surcharge, reflecting the rates established through the settlement. These rates became effective with bills rendered on and after January 28, 2009, for usage on and after December 19, 2008. In addition, the existing recovery mechanism for incremental purchased power capacity costs ceased as of January 28, 2009, with purchased power capacity costs then subsumed within the base rates set in this proceeding. The agreement adopted by the PUCT also reconciles fuel and purchased power costs for the period January 1, 2006 through March 31, 2007. Certain Texas municipalities exercised their original jurisdiction and took final action to approve rates consistent with the interim rates approved by the ALJs. In March 2009, the PUCT approved the settlement, which made the interim rates final.

Transition to Competition Costs

In August 2005, Entergy Texas filed with the PUCT an application for recovery of its transition to competition costs. Entergy Texas requested recovery of $189 million in transition to competition costs through implementation of a 15-year rider. The $189 million represents transition to competition costs Entergy Texas incurred from June 1, 1999 through June 17, 2005 in preparing for the potential of competition in its Texas service area, including attendant AFUDC, and all carrying costs projected to be incurred on the transition to competition costs through February 28, 2006. The $189 million is before any gross-up for taxes or carrying costs over the 15-year recovery period. Entergy Texas reached a unanimous settlement agreement, which the PUCT approved in June 2006, on all issues with the active parties in the transition to competition cost recovery case. The agreement allows Entergy Texas to recover $14.5 million per year in transition to competition costs over a 15-year period. Entergy Texas implemented rates based on this revenue level on March 1, 2006.

Filings with the LPSC

Formula Rate Plans (Entergy Gulf States Louisiana and Entergy Louisiana)

In March 2005, the LPSC approved a settlement proposal to resolve various dockets covering a range of issues for Entergy Gulf States Louisiana and Entergy Louisiana. The settlement included the establishment of a three-year formula rate plan for Entergy Gulf States Louisiana that, among other provisions, establishes a return on common equity mid-point of 10.65% for the initial three-year term of the plan and permits Entergy Gulf States Louisiana to recover incremental capacity costs outside of a traditional base rate proceeding. Under the formula rate plan, over- and under-earnings outside an allowed range of 9.9% to 11.4% are allocated 60% to customers and 40% to Entergy Gulf States Louisiana. Entergy Gulf States Louisiana made its initial formula rate plan filing in June 2005. The formula rate plan was subsequently extended one year.

Entergy Louisiana made a rate filing with the LPSC requesting a base rate increase in January 2004. In May 2005 the LPSC approved a settlement that included the adoption of a three-year formula rate plan, the terms of which included an ROE mid-point of 10.25% for the initial three-year term of the plan and permit Entergy Louisiana to recover incremental capacity costs outside of a traditional base rate proceeding. Under the formula rate plan, over- and under-earnings outside an allowed regulatory range of 9.45% to 11.05% will be allocated 60% to customers and 40% to Entergy Louisiana. The initial formula rate plan filing was made in May 2006.

Entergy Corporation and Subsidiaries
Notes to Financial Statements

As discussed below the formula rate plans for Entergy Gulf States Louisiana and Entergy Louisiana have been extended, with return on common equity provisions consistent with previously approved provisions, to cover the 2008, 2009, and 2010 test years.

Retail Rates - Electric

(Entergy Louisiana)

In October 2009 the LPSC approved a settlement that resolves Entergy Louisiana's 2006 and 2007 test year filings. The settlement provides for a new formula rate plan for the 2008, 2009, and 2010 test years. Entergy Louisiana is permitted, effective with the November 2009 billing cycle, to reset its rates to achieve a 10.25% return on equity for the 2008 test year. 10.25% is the target midpoint return on equity for the new formula rate plan, with an earnings bandwidth of +/- 80 basis points (9.45% - 11.05%). The rate reset, a $2.5 million increase that includes a $16.3 million cost of service adjustment less a $13.8 million net reduction for decreased capacity costs and a base rate reclassification, was implemented for the November 2009 billing cycle, and the rate reset will be subject to refund pending review of the 2008 test year filing that was made on October 21, 2009. The settlement does not allow recovery through the formula rate plan of most of Entergy Louisiana's costs associated with Entergy's stock option plan. Pursuant to the settlement Entergy Louisiana refunded to its customers $12.9 million, which includes interest, in the November 2009 billing cycle. The LPSC Staff and one intervenor filed comments on the 2008 test year filing in January 2010. Entergy Louisiana has until March 2010 to provide an initial response to the proposed adjustments and discovery is ongoing. Entergy Louisiana will implement any agreed changes by March 15, 2010. A procedural schedule to address any contested issues would be set after March 15, 2010.

In December 2009, Entergy Louisiana filed an application seeking LPSC approval for a $10.3 million revenue requirement to provide supplemental funding for the decommissioning trust maintained for Waterford 3, in response to an NRC notification of a projected shortfall of decommissioning funding assurance. Currently, Entergy Louisiana has $2.2 million in annual retail rates for decommissioning funding.

In May 2008, Entergy Louisiana made its formula rate plan filing with the LPSC for the 2007 test year, seeking an $18.4 million rate increase, comprised of $12.6 million of recovery of incremental and deferred capacity costs and $5.8 million based on a cost of service revenue deficiency related to continued lost contribution to fixed costs associated with the loss of customers due to Hurricane Katrina. In August 2008, Entergy Louisiana implemented a $43.9 million formula rate plan decrease to remove interim storm cost recovery and to reduce the storm damage accrual. Entergy Louisiana then implemented a $16.9 million formula rate plan increase, subject to refund, effective the first billing cycle in September 2008, comprised of $12.6 million of recovery of incremental and deferred capacity costs and $4.3 million based on a cost of service deficiency.

In May 2007, Entergy Louisiana made its formula rate plan filing with the LPSC for the 2006 test year, indicating a 7.6% earned return on common equity. In September 2007, Entergy Louisiana modified its formula rate plan filing to reflect its implementation of certain adjustments proposed by the LPSC Staff in its review of Entergy Louisiana's original filing with which Entergy Louisiana agreed, and to reflect its implementation of an $18.4 million annual formula rate plan increase comprised of (1) a $23.8 million increase representing 60% of Entergy Louisiana's revenue deficiency, and (2) a $5.4 million decrease for reduced incremental and deferred capacity costs. In October 2007, Entergy Louisiana implemented a $7.1 million formula rate plan decrease that was due primarily to the reclassification of certain franchise fees from base rates to collection via a line item on customer bills pursuant to an LPSC Order.

In May 2006, Entergy Louisiana made its formula rate plan filing with the LPSC for the 2005 test year. Entergy Louisiana modified the filing in August 2006 to reflect a 9.45% return on equity which is within the allowed bandwidth. The modified filing includes an increase of $24.2 million for interim recovery of storm costs from Hurricanes Katrina and Rita and a $119.2 million rate increase to recover LPSC-approved incremental deferred and ongoing capacity costs. The filing requested recovery of approximately $50 million for the amortization of capacity deferrals over a three-year period, including carrying charges, and approximately $70 million for ongoing capacity costs. The increase was implemented, subject to refund, with the first billing cycle of September 2006. Entergy Louisiana subsequently updated its formula rate plan rider to reflect adjustments proposed by the LPSC Staff with which it agrees. The adjusted return on equity of 9.56% remains within the allowed bandwidth. Ongoing and deferred incremental capacity costs were reduced to $118.7 million. The updated formula rate plan rider was implemented, subject to refund, with the first billing cycle of October 2006. An uncontested stipulated settlement was filed in February 2008 that left the current base rates in place, and the LPSC approved the settlement in March 2008. In the settlement Entergy Louisiana agreed to credit customers $7.2 million, plus $0.7 million of interest, for customer contributions to the Central States Compact in Nebraska that was never completed and agreed to a one-time $2.6 million deduction from the deferred capacity cost balance. The credit, for which Entergy Louisiana had previously recorded a provision, was made in May 2008.

(Entergy Gulf States Louisiana)

In October 2009 the LPSC approved a settlement that resolves Entergy Gulf States Louisiana's 2007 test year filing. The settlement provides for a new formula rate plan for the 2008, 2009, and 2010 test years. Entergy Gulf States Louisiana is permitted, effective with the November 2009 billing cycle, to reset its rates to achieve a 10.65% return on equity for the 2008 test year. 10.65% is the target midpoint return on equity for the new formula rate plan, with an earnings bandwidth of +/- 75 basis points (9.90% - 11.40%). The rate reset, a $44.3 million increase that includes a $36.9 million cost of service adjustment, plus $7.4 million net for increased capacity costs and a base rate reclassification, was implemented for the November 2009 billing cycle, and the rate reset will be subject to refund pending review of the 2008 test year filing that was made on October 21, 2009. The settlement does not allow recovery through the formula rate plan of most of Entergy Gulf States Louisiana's costs associated with Entergy's stock option plan. Pursuant to the settlement Entergy Gulf States Louisiana refunded to its customers $3.7 million, which includes interest, in the November 2009 billing cycle. In January 2010, Entergy Gulf States Louisiana implemented an additional $23.9 million rate increase pursuant to a special rate implementation filing made in December 2009, primarily for incremental capacity costs approved by the LPSC. The discovery and comment period for the 2008 test year filing is currently open, and Entergy Gulf States Louisiana will implement any agreed changes by March 15, 2010. A procedural schedule to address any contested issues would be set after March 15, 2010.

In December 2009, Entergy Gulf States Louisiana filed an application seeking LPSC approval for a $9.7 million revenue requirement to provide supplemental funding for the decommissioning trust maintained for the LPSC-regulated 70% share of River Bend, in response to an NRC notification of a projected shortfall of decommissioning funding assurance. Currently, Entergy Gulf States Louisiana's annual retail rates contain no amount for decommissioning funding.

In May 2008, Entergy Gulf States Louisiana made its formula rate plan filing with the LPSC for the 2007 test year. The filing reflected a 9.26% return on common equity, which was below the allowed earnings bandwidth, and indicated a $5.4 million revenue deficiency, offset by a $4.1 million decrease in required additional capacity costs. Entergy Gulf States Louisiana implemented a $20.7 million formula rate plan decrease, subject to refund, effective the first billing cycle in September 2008. The decrease included removal of interim storm cost recovery and a reduction in the storm damage accrual. Entergy Gulf States Louisiana then implemented a $16.0 million formula rate plan increase, subject to refund, effective the first billing cycle in October 2008 to collect previously deferred and ongoing costs associated with LPSC approved additional capacity, including the Ouachita power plant. In November 2008 Entergy Gulf States Louisiana filed to implement an additional increase of $9.3 million to recover the costs of a new purchased power agreement.

Entergy Corporation and Subsidiaries
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In May 2007, Entergy Gulf States Louisiana made its formula rate plan filing with the LPSC for the 2006 test year. The filing reflected a 10.0% return on common equity, which was within the allowed earnings bandwidth, and an anticipated formula rate plan decrease of $23 million annually attributable to adjustments outside of the formula rate plan sharing mechanism related to capacity costs and the anticipated securitization of storm costs related to Hurricane Katrina and Hurricane Rita and the securitization of a storm reserve. In September 2007, Entergy Gulf States Louisiana modified the formula rate plan filing to reflect a 10.07% return on common equity, which was still within the allowed bandwidth. The modified filing also reflected implementation of a $4.1 million rate increase, subject to refund, attributable to recovery of additional LPSC-approved incremental deferred and ongoing capacity costs. The rate decrease anticipated in the original filing did not occur because of the additional capacity costs approved by the LPSC, and because securitization of storm costs associated with Hurricane Katrina and Hurricane Rita and the establishment of a storm reserve had not yet occurred. In October 2007, Entergy Gulf States Louisiana implemented a $16.4 million formula rate plan decrease that was due to the reclassification of certain franchise fees from base rates to collection via a line item on customer bills pursuant to an LPSC order. In March 2008 the LPSC approved an uncontested stipulated settlement that left the current base rates in place and extended the formula rate plan for one year.

In May 2006, Entergy Gulf States Louisiana made its formula rate plan filing with the LPSC for the 2005 test year. Entergy Gulf States Louisiana modified the filing in August 2006 to reflect an 11.1% return on common equity which is within the allowed bandwidth. The modified filing includes a formula rate plan increase of $17.2 million annually that provides for 1) interim recovery of $10.5 million of storm costs from Hurricane Katrina and Hurricane Rita and 2) recovery of $6.7 million of LPSC-approved incremental deferred and ongoing capacity costs. The increase was implemented with the first billing cycle of September 2006. In May 2007 the LPSC approved a settlement between Entergy Gulf States Louisiana and the LPSC staff, affirming the rates that were implemented in September 2006.

Retail Rates - Gas (Entergy Gulf States Louisiana)

In January 2010, Entergy Gulf States Louisiana filed with the LPSC its gas rate stabilization plan for the test year ended September 30, 2009. The filing showed an earned return on common equity of 10.87%, which is within the earnings bandwidth of 10.5% plus or minus fifty basis points. The sixty day review and comment period for this filing remains open.

In January 2009, Entergy Gulf States Louisiana filed with the LPSC its gas rate stabilization plan for the test year ended September 30, 2008. The filing showed a revenue deficiency of $529 thousand based on a return on common equity mid-point of 10.5%. In April 2009, Entergy Gulf States Louisiana implemented a $255 thousand rate increase pursuant to an uncontested settlement with the LPSC staff.

In January 2008, Entergy Gulf States Louisiana filed with the LPSC its gas rate stabilization plan for the test year ending September 30, 2007. The filing showed a revenue deficiency of $3.7 million based on a return on common equity mid-point of 10.5%. Entergy Gulf States Louisiana implemented a $3.4 million rate increase in April 2008 pursuant to an uncontested agreement with the LPSC staff.

In January 2007, Entergy Gulf States Louisiana filed with the LPSC its gas rate stabilization plan for the test year ending September 30, 2006. The filing showed a revenue deficiency of $3.5 million based on a return on common equity mid-point of 10.5% In March 2007, Entergy Gulf States Louisiana filed a set of rate and rider schedules that reflected all proposed LPSC staff adjustments and implemented a $2.4 million base rate increase effective with the first billing cycle of April 2007 pursuant to the rate stabilization plan.

Filings with the MPSC (Entergy Mississippi)

Formula Rate Plan Filings

In September 2009, Entergy Mississippi filed proposed modifications to its formula rate plan rider. The proposed modifications include: (1) resetting Entergy Mississippi's return on common equity to the middle of the formula rate plan bandwidth each year and eliminating the 50/50 sharing in the current plan, (2) replacing the current rate change limit of two percent of revenues subject to a $14.5 million revenue adjustment cap with a proposed limit of four percent of revenues, (3) implementing a projected test year for the annual filing and subsequent look-back for the prior year, and (4) modifying the performance measurement process.

In March 2009, Entergy Mississippi made with the MPSC its annual scheduled formula rate plan filing for the 2008 test year. The filing reported a $27.0 million revenue deficiency and an earned return on common equity of 7.41%. Entergy Mississippi requested a $14.5 million increase in annual electric revenues, which is the maximum increase allowed under the terms of the formula rate plan. The MPSC issued an order on June 30, 2009, finding that Entergy Mississippi's earned return was sufficiently below the lower bandwidth limit set by the formula rate plan to require a $14.5 million increase in annual revenues, effective for bills rendered on or after June 30, 2009.

In March 2008, Entergy Mississippi made its annual scheduled formula rate plan filing for the 2007 test year with the MPSC. The filing showed that a $10.1 million increase in annual electric revenues is warranted. In June 2008, Entergy Mississippi reached a settlement with the Mississippi Public Utilities Staff that would result in a $3.8 million rate increase. In January 2009 the MPSC rejected the settlement and left the current rates in effect. Entergy Mississippi appealed the MPSC's decision to the Mississippi Supreme Court. After the decision of the MPSC regarding the formula rate plan filing for the 2008 test year, Entergy Mississippi filed a motion to dismiss its appeal to the Mississippi Supreme Court.

In March 2007, Entergy Mississippi made its annual scheduled formula rate plan filing for the 2006 test year with the MPSC. The filing showed that an increase of $12.9 million in annual electric revenues is warranted. In June 2007 the MPSC approved a joint stipulation between Entergy Mississippi and the Mississippi Public Utilities staff that provides for a $10.5 million rate increase, which was effective beginning with July 2007 billings.

Filings with the City Council (Entergy New Orleans)

Formula Rate Plans and Storm-related Riders

On July 31, 2008, Entergy New Orleans filed an electric and gas base rate case with the City Council. On April 2, 2009, the City Council approved a comprehensive settlement. The settlement provided for a net $35.3 million reduction in combined fuel and non-fuel electric revenue requirement, including conversion of the $10.6 million voluntary recovery credit to a permanent reduction and substantial realignment of Grand Gulf cost recovery from fuel to electric base rates, and a $4.95 million gas base rate increase, both effective June 1, 2009, with adjustment of the customer charges for all rate classes. A new three-year formula rate plan was also adopted, with terms including an 11.1% benchmark electric return on common equity (ROE) with a +/- 40 basis point bandwidth and a 10.75% benchmark gas ROE with a +/- 50 basis point bandwidth. Earnings outside the bandwidth reset to the midpoint benchmark ROE, with rates changing on a prospective basis depending on whether Entergy New Orleans is over- or under-earning. The formula rate plan also includes a recovery mechanism for City Council-approved capacity additions, plus provisions for extraordinary cost changes and force majeure events.

The rate case settlement also included $3.1 million per year in electric rates to fund the Energy Smart energy efficiency programs. In September 2009 the City Council approved the energy efficiency programs filed by Entergy New Orleans. The rate settlement provides an incentive for Entergy New Orleans to meet or exceed energy savings targets set by the City Council and provides a mechanism for Entergy New Orleans to recover lost contribution to fixed costs associated with the energy savings generated from the energy efficiency programs. The programs are expected to begin in 2010.

In June 2006, Entergy New Orleans made its annual formula rate plan filings with the City Council. The filings presented various alternatives to reflect the effect of Entergy New Orleans' lost customers and decreased revenue following Hurricane Katrina. The alternative that Entergy New Orleans recommended adjusts for lost customers and assumes that the City Council's June 2006 decision to allow recovery of all Grand Gulf costs through the fuel adjustment clause stays in place during the rate-effective period (a significant portion of Grand Gulf costs was previously recovered through base rates).

At the same time as it made its formula rate plan filings, Entergy New Orleans also filed with the City Council a request to implement two storm-related riders. With the first rider, Entergy New Orleans sought to recover the electric and gas restoration costs that it had actually spent through March 31, 2006. Entergy New Orleans also proposed semiannual filings to update the rider for additional restoration spending and also to consider the receipt of CDBG funds or insurance proceeds that it may receive. With the second rider, Entergy New Orleans sought to establish a storm reserve to provide for the risk of another storm.

In October 2006, the City Council approved a settlement agreement that resolved Entergy New Orleans' rate and storm-related rider filings by providing for phased-in rate increases, while taking into account with respect to storm restoration costs the anticipated receipt of CDBG funding as recommended by the Louisiana Recovery Authority. The settlement provided for a 0% increase in electric base rates through December 2007, with a \$3.9 million increase implemented in January 2008. Recovery of all Grand Gulf costs through the fuel adjustment clause was continued. Gas base rates increased by \$4.75 million in November 2006 and increased by additional \$1.5 million in March 2007 and an additional \$4.75 million in November 2007. The settlement called for Entergy New Orleans to file a base rate case by July 31, 2008, which it did as discussed above. The settlement agreement discontinued the formula rate plan and the generation performance-based plan but permitted Entergy New Orleans to file an application to seek authority to implement formula rate plan mechanisms no sooner than six months following the effective date of the implementation of the base rates resulting from the July 31, 2008 base rate case. The settlement also authorized a \$75 million storm reserve for damage from future storms, which will be created over a ten-year period through a storm reserve rider beginning in March 2007. These storm reserve funds will be held in a restricted escrow account.

In January 2008, Entergy New Orleans voluntarily implemented a 6.15% base rate credit (the recovery credit) for electric customers, which returned approximately \$11.3 million to electric customers in 2008. Entergy New Orleans was able to implement this credit because during 2007 the recovery of New Orleans after Hurricane Katrina was occurring faster than expected in 2006 projections. In addition, Entergy New Orleans committed to set aside \$2.5 million for an energy efficiency program focused on community education and outreach and weatherization of homes.

Fuel Adjustment Clause Litigation

In April 1999, a group of ratepayers filed a complaint against Entergy New Orleans, Entergy Corporation, Entergy Services, and Entergy Power in state court in Orleans Parish purportedly on behalf of all Entergy New Orleans ratepayers. The plaintiffs seek treble damages for alleged injuries arising from the defendants' alleged violations of Louisiana's antitrust laws in connection with certain costs passed on to ratepayers in Entergy New Orleans' fuel adjustment filings with the City Council. In particular, plaintiffs allege that Entergy New Orleans improperly included certain costs in the calculation of fuel charges and that Entergy New Orleans imprudently purchased high-cost fuel or energy from other Entergy affiliates. Plaintiffs allege that Entergy New Orleans and the other defendant Entergy companies conspired to make these purchases to the detriment of Entergy New Orleans' ratepayers and to the benefit of Entergy's shareholders, in violation of Louisiana's antitrust laws. Plaintiffs also seek to recover interest and attorneys' fees. Entergy filed exceptions to the plaintiffs' allegations, asserting, among other things, that jurisdiction over these issues rests with the City Council and the FERC. In March 2004, the plaintiffs supplemented and amended their petition. If necessary, at the appropriate time, Entergy will also raise its defenses to the antitrust claims. The suit in state court was stayed by stipulation of the parties and order of the court pending review of the decision by the City Council in the proceeding discussed in the next paragraph.

Plaintiffs also filed a corresponding complaint with the City Council in order to initiate a review by the City Council of the plaintiffs' allegations and to force restitution to ratepayers of all costs they allege were improperly and imprudently included in the fuel adjustment filings. Testimony was filed on behalf of the plaintiffs in this proceeding asserting, among other things, that Entergy New Orleans and other defendants have engaged in fuel procurement and power purchasing practices and included costs in Entergy New Orleans' fuel adjustment that could have resulted in Entergy New Orleans customers being overcharged by more than $100 million over a period of years. Hearings were held in February and March 2002. In February 2004, the City Council approved a resolution that resulted in a refund to customers of $11.3 million, including interest, during the months of June through September 2004. In May 2005 the Civil District Court for the Parish of Orleans affirmed the City Council resolution, finding no support for the plaintiffs' claim that the refund amount should be higher. In June 2005, the plaintiffs appealed the Civil District Court decision to the Louisiana Fourth Circuit Court of Appeal. On February 25, 2008, the Fourth Circuit Court of Appeal issued a decision affirming in part, and reversing in part, the Civil District Court's decision. Although the Fourth Circuit Court of Appeal did not reverse any of the substantive findings and conclusions of the City Council or the Civil District Court, the Fourth Circuit found that the amount of the refund was arbitrary and capricious and increased the amount of the refund to $34.3 million. Entergy New Orleans and the City Council filed with the Louisiana Supreme Court seeking, among other things, review and reversal of the Fourth Circuit decision. In April 2009 the Louisiana Supreme Court reversed the decision of the Louisiana Fourth Circuit Court of Appeal and reinstated the decision of the Civil District Court. In May 2009 the Louisiana Supreme Court denied the plaintiffs' request for rehearing. In January 2010 the plaintiffs filed a motion to lift the stay and to supplement and amend their state court petition.

In the Entergy New Orleans bankruptcy proceeding, the named plaintiffs in the Entergy New Orleans fuel clause lawsuit, together with the named plaintiffs in the Entergy New Orleans rate of return lawsuit, filed a Complaint for Declaratory Judgment asking the court to declare that Entergy New Orleans, Entergy Corporation, and Entergy Services are a single business enterprise, and, as such, are liable in solido with Entergy New Orleans for any claims asserted in the Entergy New Orleans fuel adjustment clause lawsuit and the Entergy New Orleans rate of return lawsuit, and, alternatively, that the automatic stay be lifted to permit the movants to pursue the same relief in state court. The bankruptcy court dismissed the action on April 26, 2006. The matter was appealed to the U.S. District Court for the Eastern District of Louisiana, and the district court affirmed the dismissal in October 2006, but on different grounds, concluding that the lawsuit was premature. In Entergy New Orleans' plan of reorganization that was confirmed by the bankruptcy court in May 2007, the plaintiffs' claims are treated as unimpaired "Litigation Claims," which will "ride through" the bankruptcy proceeding, with any legal, equitable and contractual rights to which the plaintiffs' Litigation Claim entitles the plaintiffs unaltered by the plan of reorganization

Electric Industry Restructuring (Entergy Texas)

In June 2009, a law was enacted in Texas that requires Entergy Texas to cease all activities relating to Entergy Texas' transition to competition. The law allows Entergy Texas to remain a part of the SERC Region, although it does not prevent Entergy Texas from joining the Southwest Power Pool. The law provides that proceedings to certify a power region that Entergy Texas belongs to as a qualified power region can be initiated by the PUCT, or on motion by another party, when the conditions supporting such a proceeding exist. Under the new law, the PUCT may not approve a transition to competition plan for Entergy Texas until the expiration of four years from the PUCT's certification of Entergy Texas' power region. In response to the new law, Entergy Texas in June 2009 gave notice to the PUCT of the withdrawal of its previously filed transition to competition plan, and requested that its transition to competition proceeding be dismissed. In July 2009 the ALJ dismissed the proceeding.

The new law also contains provisions that allow Entergy Texas to be included in a cost recovery mechanism that permits annual filings for the recovery of reasonable and necessary expenditures for transmission infrastructure improvement and changes in wholesale transmission charges. This mechanism was previously available to other non-ERCOT Texas utility companies, but not to Entergy Texas.

Entergy Corporation and Subsidiaries
Notes to Financial Statements

The new law further amends already existing law that had required Entergy Texas to propose for PUCT approval a tariff to allow eligible customers the ability to contract for competitive generation. The amending language in the new law provides, among other things, that: 1) the tariff shall not be implemented in a manner that harms the sustainability or competitiveness of manufacturers who choose not to participate in the tariff; 2) Entergy Texas shall "purchase competitive generation service, selected by the customer, and provide the generation at retail to the customer"; and 3) Entergy Texas shall provide and price transmission service and ancillary services under that tariff at a rate that is unbundled from its cost of service. The new law directs that the PUCT may not issue an order on the tariff that is contrary to an applicable decision, rule, or policy statement of a federal regulatory agency having jurisdiction. The new law provides that the PUCT shall approve, reject, or modify the proposed tariff not later than September 1, 2010

Interruptible Load Proceeding (Entergy Louisiana)

The FERC issued orders in September 2005 and 2007 in which it directed Entergy to remove all interruptible load from certain computations of peak load responsibility commencing April 1, 2004 and to issue any necessary refunds to reflect this change. In addition, in September 2008 the FERC directed the Utility operating companies to make refunds for the period May 1995 through July 1996. In October 2009, the LPSC issued an order approving the flow through to retail rates of the LPSC-jurisdictional portion of the payments and credits resulting from the FERC's orders that had not yet been flowed through to retail rates, which required a net refund to Entergy Louisiana retail customers of $17.6 million, including interest. Of this amount, $5.4 million was refunded subject to adjustment in the event that future action by the FERC or the D.C. Circuit Court of Appeals results in a reversal or change in the amount of the refunds ordered by the FERC in September 2008.

Ouachita

In September 2008, Entergy Arkansas purchased the Ouachita Plant, a 789 MW three-train gas-fired combined cycle generating turbine (CCGT) electric power plant located 20 miles south of the Arkansas state line near Sterlington, Louisiana, for approximately $210 million from a subsidiary of Cogentrix Energy, Inc. Entergy Arkansas received the plant, materials and supplies, and related real estate in the transaction. The FERC and the APSC approved the acquisition. The APSC also approved the recovery of the acquisition and ownership costs through a rate rider and the planned sale of one-third of the capacity and energy to Entergy Gulf States Louisiana.

The LPSC also approved the purchase of one-third of the capacity and energy by Entergy Gulf States Louisiana, subject to certain conditions, including a study to determine the costs and benefits of Entergy Gulf States Louisiana exercising an option to purchase one-third of the plant (Unit 3) from Entergy Arkansas. In April 2009, Entergy Gulf States Louisiana made a filing with the LPSC seeking approval of Entergy Gulf States Louisiana exercising its option to convert its purchased power agreement into the ownership interest in Unit 3 and a one-third interest in the Ouachita common facilities. In September 2009 the LPSC, pursuant to an uncontested settlement, approved the acquisition and a cost recovery mechanism. Entergy Gulf States Louisiana purchased Unit 3 and a one-third interest in the Ouachita common facilities for $75 million in November 2009.

IDACORP

IDACORP

Demand-Side Management Programs

In 2009, Idaho Power spent approximately $35 million on energy efficiency and targeted demand reduction programs. Approximately $33 million of funding for these programs came from Idaho and Oregon energy efficiency tariff riders. The balance of the funding comes from Idaho Power base rates and from the remaining funds from the BPA's Conservation and Renewables Discount, which was discontinued in 2007.

Idaho and Oregon Rate Orders: Idaho Power received five additional rate orders from the IPUC and the OPUC at the end of May 2009. The IPUC rate orders are for the Fixed Cost Adjustment mechanism, Idaho Energy Efficiency Rider, Advanced Metering Infrastructure (AMI), and PCA, and the OPUC rate order is for the Annual Power Cost Update. Each of these orders increases rates, but only the AMI order, relating to the installation of new meters, increases Idaho Power's rate base.

Idaho Energy Efficiency Rider (Rider)
Idaho Power's Rider is the chief funding mechanism for Idaho Power's investment in energy efficiency, conservation, and demand response programs. Effective June 1, 2009, Idaho Power collects 4.75 percent of base revenues, or approximately \$29-\$33 million annually, under the Rider.

In the 2008 general rate case, Idaho Power requested that the IPUC explicitly find that Idaho Power's expenditures between 2002 and 2007 of \$29 million of funds obtained from the Rider were prudently incurred and no longer subject to potential disallowance. In 2009, the IPUC approved a stipulation identifying \$14.3 million of Rider funding as prudent, and on January 25, 2010, Idaho Power and the IPUC Staff filed a stipulation for approval by the IPUC to find the remaining expenditures through 2007 were prudently incurred.

On October 5, 2009, Idaho Power and other investor-owned electric utilities serving in Idaho began a series of informal public workshop with the IPUC Staff to discuss how energy efficiency evaluation and prudency will be determined on a prospective basis. As a result a Memorandum of Understanding (MOU) written by Staff, Idaho Power and other investor-owned electric utilities in Idaho has been signed outlining a process for future energy expenditure approval. This document was filed with the IPUC on January 25, 2010.

In the first quarter of 2010, Idaho Power expects to request a similar prudency determination from the IPUC for Rider expenditures in 2008 and 2009. Idaho Power spent approximately \$19 million in 2008 and \$33 million in 2009 for rider-funded energy efficiency and demand response initiatives in its Idaho and Oregon jurisdictions combined. The increase in spending in 2009 reflects Idaho Power's growing emphasis on these programs, such as implementation of a revised irrigation peak rewards program and commercial demand response program in 2009.

Usage: Changes in usage decreased general business revenue $38 million. Irrigation usage decreased 14 percent primarily due to increased precipitation. Commercial and industrial usage also declined due to a weaker economy and increased energy efficiency. Idaho Power does have in place the Load Growth Adjustment Rate (LGAR) and FCA mechanisms, both of which diminish the impact of changes in sales volumes from levels included in base rates.

PCA Workshops: In its order approving Idaho Power's 2008-2009 PCA, the IPUC directed Idaho Power to set up workshops with the IPUC Staff and several of Idaho Power's largest customers to address issues not resolved in that PCA filing. The workshops resulted in the following changes to the PCA mechanism, effective February 1, 2009:

- PCA sharing ratio – the PCA allocates the deviations in net power supply expenses between customers (95 percent) and shareholders (5 percent). The previous sharing ratio was 90/10.
- LGAR – the LGAR is an element of the PCA formula that is intended to eliminate recovery of power supply expenses associated with load growth resulting from changing weather conditions, a growing customer base, or changing customer use patterns. The 2007 general rate case reset the LGAR from $29.41 to $62.79 per MWh, but applied that rate to only 50 percent of the load growth beginning in March 2008. The stipulation agreed on a new formula for calculating the LGAR. Based on the final rates approved by the IPUC in the 2008 general rate case and the supporting data, the current LGAR is $26.63 per MWh, effective February 1, 2009.
- Use of Idaho Power's operation plan power supply cost forecast – the operation plan forecast may better match current collections with actual net power supply costs in the year they are incurred and result in smaller amounts being included in the following year's "true-up" rate, beginning with the 2009-2010 PCA filing.
- Inclusion of third-party transmission expense – transmission expenses paid to third parties to facilitate wholesale purchases and sales of energy, including losses, are a necessary component of net power supply costs. Deviation in these costs from levels included in base rates is now reflected in PCA computations.
- Adjusted distribution of base net power supply costs – base net power supply costs are distributed throughout the year based upon the monthly shape of normalized revenues for purposes of the PCA deferral calculation.

Fixed Cost Adjustment Mechanism (FCA)

The FCA mechanism began as a pilot program for Idaho Power's Idaho residential and small general service customers, running from 2007 through 2009. The FCA is a rate mechanism designed to remove Idaho Power's disincentive to invest in energy efficiency programs by separating (or decoupling) the recovery of fixed costs from the variable kilowatt-hour charge and linking it instead to a set amount per customer. On October 1, 2009, Idaho Power filed an application with the IPUC to make the FCA mechanism permanent beginning January 1, 2010. The application is being processed under modified procedure.

Idaho Power accrued $6.6 million related to the FCA in 2009; subject to IPUC approval, recovery should begin June 1, 2010. The IPUC approved a rate increase effective June 1, 2009, through May 31, 2010, to recover $2.7 million of fixed costs under-recovered during 2008. The IPUC approved a rate reduction, effective June 1, 2008 through May 31, 2009, to return $2.4 million of fixed costs over-recovered in 2007.

Idaho:

Idaho Power has a PCA mechanism that provides for annual adjustments to the rates charged to its Idaho retail customers. The PCA tracks Idaho Power's actual net power supply costs (primarily fuel and purchased power less off-system sales) and compares these amounts to net power supply costs currently being recovered in retail rates.

The annual adjustments are based on two components:

- A forecast component, based on a forecast of net power supply costs in the coming year as compared to net power supply costs in base rates; and
- A true-up component, based on the difference between the previous year's actual net power supply costs and the previous year's forecast. This component also includes a balancing mechanism so that, over time, the actual collection or refund of authorized true-up dollars matches the amounts authorized. The true-up component is calculated monthly, and interest is applied to the balance.

PG&E Corp.

Hazardous Substance Ratemaking Mechanism

Environmental costs associated with the clean-up of sites that contain hazardous substances are subject to a CPUC-approved ratemaking mechanism under which the Utility is authorized to recover hazardous waste remediation costs for environmental claims from customers (*e g* , for costs of cleaning up the Utility's facilities and sites where the Utility's hazardous substances have been sent). This mechanism allows the Utility to include 90% of eligible hazardous waste remediation costs in the Utility's rates without a reasonableness review. (The cost of environmental remediation associated with the Hinkley natural gas compressor site is not recoverable from customers under this mechanism.) Ten percent of any net insurance recoveries associated with hazardous waste remediation sites are assigned to the Utility's customers. The balances of any insurance recoveries (90%) are retained by the Utility until it has been reimbursed for the 10% share of clean-up costs not included in rates. Any insurance recoveries above full cost reimbursement levels are allocated 60% to customers and 40% to the Utility. Finally, 10% of any recoveries from the Utility's claims against third parties associated with hazardous waste remediation sites are retained by the Utility, with the remainder, 90% of any such recoveries, assigned to the Utility's customers.

Hazardous waste remediation costs are rising and are likely to be significant into the foreseeable future. Based on the Utility's past experience, it believes that it can recover most of the future costs that it may incur to remediate hazardous waste through rates and insurance recoveries. The Utility cannot provide assurance, however, that these costs will not be material, or that the Utility will be able to recover its costs in the future.

Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, estimated costs may vary significantly from actual costs, and the amount of additional future costs may be material to results of operations in the period in which they are recognized. For more information about environmental remediation liabilities, see the sections of MD&A entitled "Environmental Matters" and "Critical Accounting Polices" and Note 16 of the Notes to the Consolidated Financial Statements in the 2009 Annual Report which information is incorporated herein by reference and included in Exhibit 13 to this report.

To develop retail rates, the revenue requirements are allocated among customer classes (mainly residential, commercial, industrial, and agricultural) and to various service components (mainly customer, demand, and energy). Specific rate components are designed to produce the required revenue. Rate changes become effective prospectively on or after the date of CPUC or FERC decisions. Most rate changes approved by the CPUC throughout the year are consolidated to take effect on the first day of the following year.

Through cost-of-service ratemaking, rates are developed to produce the revenue requirements, including the authorized return on rate base. The Utility may be unable to earn its authorized rate of return because the CPUC or the FERC excludes some of the Utility's actual costs from the revenue requirements or because the Utility's actual costs are higher than those reflected in the revenue requirements.

While the CPUC generally uses cost-of-service ratemaking to develop revenue requirements and rates, it selectively uses incentive ratemaking, which bases rates on the extent to which the utilities meet objective or fixed standards or goals, such as reliability standards or energy efficiency goals, instead of on the cost of providing service.

Electricity and Natural Gas Distribution and Electricity Generation Operations

General Rate Cases

The General Rate Case ("GRC") is the primary proceeding in which the CPUC determines the amount of revenue requirements that the Utility is authorized to collect from customers to recover the Utility's basic business and operational costs related to its electricity and natural gas distribution and electricity generation operations. The CPUC generally conducts a GRC every three years. The CPUC sets revenue requirement levels for a three-year rate period based on a forecast of costs for the first or "test" year. Typical interveners in the Utility's GRC include the CPUC's Division of Ratepayer Advocates and The Utility Reform Network. On March 15, 2007, the CPUC approved a multi-party settlement agreement to resolve the Utility's 2007 GRC. The decision set the Utility's electricity and natural gas distribution and electricity generation revenue requirements for a four-year period, from 2007 through 2010, rather than for a typical three-year period. On December 21, 2009, the Utility filed its application for the next GRC to establish revenue requirements for 2011 through 2013. For more information, see the section of MD&A entitled "Regulatory Matters" in the 2009 Annual Report.

Attrition Rate Adjustments

The CPUC may authorize the Utility to receive annual increases for the years between GRCs in the base revenues authorized for the test year of a GRC in order to avoid a reduction in earnings in those years due to, among other things, inflation and increases in invested capital. These adjustments are known as attrition rate adjustments. Attrition rate adjustments provide increases in the revenue requirements that the Utility is authorized to collect in rates for electricity and natural gas distribution and electricity generation operations. The CPUC's decision in the Utility's 2007 GRC provided for attrition adjustments for 2008, 2009, and 2010. For more information, see the section of MD&A entitled "Results of Operations" in the 2009 Annual Report.

Cost of Capital Proceedings

The CPUC authorizes the Utility's capital structure (i.e., the relative weightings of common equity, preferred equity, and debt) and the authorized rates of return on each component that the Utility may earn on its electricity and natural gas distribution and electricity generation assets. The current authorized capital structure, consisting of 52% equity, 46% long-term debt, and 2% preferred stock, will be maintained through 2012 unless the automatic adjustment mechanism described below is triggered. The Utility's current authorized rates of return that the Utility may earn on its electricity and natural gas distribution and electricity generation rate base are 6.05% for long-term debt, 5.68% for preferred stock, and 11.35% for common equity, resulting in an overall rate of return on rate base of 8.79%. The CPUC has authorized the Utility to maintain these rates through 2010.

The CPUC's cost of capital mechanism uses an interest rate index (the 12-month October through September average of the Moody's Investors Service utility bond index) to trigger changes in the authorized cost of debt, preferred stock, and equity. In any year in which the 12-month October through September average for the index increases or decreases by more than 100 basis points ("deadband") from the benchmark, the cost of equity will be adjusted by one-half of the difference between the 12-month average and the benchmark. In addition, if the mechanism is triggered, the costs of long-term debt and preferred stock will be adjusted to reflect the actual August month-end embedded costs in that year and forecasted interest rates for variable long-term debt and any new long-term debt and preferred stock forecasted to be issued in the coming year. The Utility may apply for an adjustment to either the cost of capital or the capital structure sooner based on extraordinary circumstances. The Utility's next full cost of capital application must be filed by April 20, 2012, so that any resulting changes would become effective on January 1, 2013.

Although the FERC has authority to set the Utility's rate of return for its electricity transmission operations, the rate of return is often unspecified if the Utility's transmission rates are determined through a negotiated rate settlement.

Baseline Allowance

The CPUC sets and periodically revises a baseline allowance for the Utility's residential gas and electricity customers. A customer's baseline allowance is the amount of its monthly usage that is covered under the lowest possible natural gas or electric rate. Natural gas or electricity usage in excess of the baseline allowance is covered by higher rates that increase with usage.

Rate Recovery of Costs of New Electricity Generation Resources

Overview

Each California investor-owned electric utility is responsible for procuring electricity to meet customer demand, plus applicable reserve margins, not satisfied from that utility's own generation facilities and existing electricity contracts (including DWR contracts allocated to the Utility under Assembly Bill 1X). To accomplish this, each utility must submit a long-term procurement plan covering a 10-year period to the CPUC for approval. Each long-term procurement plan must be designed to reduce GHG emissions and use the State of California's preferred loading order to meet forecasted demand (i.e., increases in future demand will be offset through energy efficiency programs, demand response programs, renewable generation resources, distributed generation resources, and new conventional generation). In December 2007, the CPUC approved the utilities' long-term electricity procurement plans, covering 2007 through 2016, subject to certain required modifications. California legislation, Assembly Bill 57, allows the utilities to recover the costs incurred in compliance with their CPUC-approved procurement plans without further after-the-fact reasonableness review. Each utility may, if appropriate, conduct a competitive request for offers ("RFO") within the parameters permitted in its approved plan to meet the utility's projected need for electricity resources. Contracts that are entered into after the RFO process are submitted to the CPUC for approval, along with a request for the CPUC to authorize revenue requirements to recover the associated costs. The utilities conduct separate competitive solicitations to meet their renewable energy resource requirements. The utilities submit the renewable energy contracts after the conclusion of these solicitations to the CPUC for approval and authorization of the associated revenue requirements. For more information about the Utility's approved long-term procurement plan covering 2007 through 2016, see "Electric Utility Operations — Electricity Resources — Future Long-Term Generation Resources" below.

The Utility recovers its electricity procurement costs and the fuel costs for the Utility's own generation facilities (but excluding the costs of electricity allocated to the Utility's customers under DWR contracts) through the Energy Resource Recovery Account ("ERRA"), a balancing account authorized by the CPUC in accordance with Assembly Bill 57. The ERRA tracks the difference between the authorized revenue requirement and actual costs incurred under the Utility's authorized procurement plans and contracts. To determine the authorized revenue requirement recorded in the ERRA, each year the CPUC reviews the Utility's forecasted costs under power purchase agreements and fuel costs. Although California legislation requiring the CPUC to adjust a utility's retail electricity rates when the forecast aggregate over-collections or under-collections in the ERRA exceed 5% of a utility's prior year electricity procurement revenues (excluding amounts collected for the DWR contracts) expired on January 1, 2006, the

CPUC has extended this mandatory rate adjustment mechanism for the length of a utility's resource commitment or 10 years, whichever is longer. The CPUC also performs compliance reviews of the procurement activities recorded in the ERRA to ensure that the Utility's procurement activities are in compliance with its approved procurement plans. The Chapter 11 Settlement Agreement also provides that the Utility will recover its reasonable costs of providing utility service, including power purchase costs.

Costs Incurred Under New Power Purchase Agreements

The CPUC has approved various power purchase agreements that the Utility has entered into with third parties in accordance with the Utility's CPUC-approved long-term procurement plan and to meet renewable energy and resource adequacy requirements. The CPUC also authorized the Utility to recover fixed and variable costs associated with these contracts through the ERRA.

For new non-renewable generation purchased from third parties under power purchase agreements, the Utility may elect to recover any above-market costs through either (1) the imposition of a non-bypassable charge on bundled and departing customers only, or (2) the allocation of the "net capacity costs" (i.e., contract price less energy revenues) to all "benefiting customers" in the utilities' service territory, including existing direct access customers and community choice aggregation customers. (For information about the status of direct access and community choice aggregation, see the section above entitled "Competition in the Electricity Industry.")

The non-bypassable charge can be imposed from the date of signing a power purchase agreement and can last for 10 years from the date the new generation unit comes on line or for the term of the contract, whichever is less. Utilities are allowed to justify a cost recovery period longer than 10 years on a case-by-case basis. If a utility elects to use the net capacity cost allocation method, the net capacity costs are allocated for the term of the contract or 10 years, whichever is shorter, starting on the date the new generation unit comes on line. Under this allocation mechanism, the energy rights to the contract are auctioned off to maximize the energy revenues and minimize the net capacity costs subject to allocation. If no bids are accepted for the energy rights, the Utility would retain the rights to the energy and would value it at market prices for the purposes of determining the net capacity costs to be allocated until the next periodic auction.

California Senate Bill 695, enacted on October 11, 2009, also includes a mechanism for recovery of above-market costs from direct access and community choice aggregation customers. The CPUC has not yet implemented this portion of Senate Bill 695.

Costs of Utility-Owned Generation Resource Projects

The CPUC-authorized revenue requirements for capital costs and non-fuel operating and maintenance costs for operating Utility-owned generation facilities are addressed in the Utility's GRC. The CPUC-authorized revenue requirements to recover the initial capital costs for utility-owned generation projects are recovered through a balancing account, the Utility Generation Balancing Account ("UGBA"), which tracks the difference between the CPUC-approved forecast of initial capital costs, adjusted from time to time as permitted by the CPUC, and actual costs. The initial revenue requirement for Utility-owned projects generally would begin to accrue in the UGBA as of the new facility's commercial operation date or the date a completed facility is transferred to the Utility, and would be included in rates on January 1 of the following year. For more information, see the section of MD&A entitled "Capital Expenditures — Proposed New Generation Facilities" in the 2009 Annual Report.

DWR Electricity and DWR Revenue Requirements

During the 2000-2001 California energy crisis, the DWR entered into long-term contracts to purchase electricity from third parties. The electricity provided under these contracts has been allocated to the electric customers of the three California investor-owned electric utilities. The DWR pays for its costs of purchasing electricity from a revenue requirement collected from these customers through a rate component called the DWR "power charge." The rates that these customers pay also include a "bond charge" to pay a share of the DWR's revenue requirements to recover costs associated with the DWR's $11.3 billion bond offering completed in November 2002. The proceeds of this bond offering were used to repay the State of California and lenders to the DWR for electricity purchases made before the implementation of the DWR's revenue requirement and to provide the DWR with funds to make its electricity purchases. The Utility acts as a billing and collection agent for the DWR for these amounts; however, amounts collected for the DWR and any adjustments are not included in the Utility's revenues.

Electricity Transmission

The Utility's electricity transmission revenue requirements and its wholesale and retail transmission rates are subject to authorization by the FERC. The Utility has two main sources of transmission revenues (1) charges under the Utility's transmission owner tariff, and (2) charges under specific contracts with wholesale transmission customers that the Utility entered into before the CAISO began its operations in March 1998. These wholesale customers are referred to as existing transmission contract customers and are charged individualized rates based on the terms of their contracts. Other customers pay transmission rates that are established by the FERC in the Utility's transmission owner tariff rate cases. These FERC-approved rates are included by the CPUC in the Utility's retail electric rates, consistent with the federal filed rate doctrine, and are collected from retail electric customers receiving bundled service.

Transmission Owner Rate Cases

The primary FERC ratemaking proceeding to determine the amount of revenue requirements that the Utility is authorized to recover for its electric transmission costs and to earn its return on equity is the transmission owner rate case (**"TO rate case"**). The Utility generally files a TO rate case every year, setting rates for a one-year period. The Utility is typically able to charge new rates, subject to refund, before the outcome of the FERC ratemaking review process. For more information about the Utility's TO rate cases, see the section of MD&A entitled "Regulatory Matters --- Electric Transmission Owner Rate Cases" in the 2009 Annual Report.

The Utility's transmission owner tariff includes two rate components. The primary component consists of base transmission rates intended to recover the Utility's operating and maintenance expenses, depreciation and amortization expenses, interest expense, tax expense, and return on equity. The Utility derives the majority of the Utility's transmission revenue from base transmission rates.

The other component consists of rates intended to reflect credits and charges from the CAISO. The CAISO credits the Utility for transmission revenues received by the CAISO. These revenues include:

- the proceeds received from the CAISO for wholesale wheeling service (i.e., the transfer of electricity that is being sold in the wholesale market) that the CAISO provides to third parties using the Utility's transmission facilities, and

- revenues that the CAISO collects from transmission users to relieve congestion on the Utility's transmission line (either in the form of financial hedges, such as firm transmission rights relating to future deliveries of electricity, or in the form of a usage charge to manage congestion relating to real-time delivery of electricity).

These revenues are adjusted by the shortfall or surplus resulting from any cost differences between the amount that the Utility is entitled to receive from existing transmission contract customers under specific contracts and the amount that the Utility is entitled to receive or be charged for scheduling services under the CAISO's rules and protocols.

The CAISO also charges the Utility for reliability service costs and imposes a transmission access charge on the Utility for the use of the CAISO-controlled electric transmission grid in serving its customers. The CAISO's transmission access charge methodology, approved by the FERC in December 2004, provided for a transition over a 10-year period, from 2001 to2010, to a uniform statewide high-voltage transmission rate. This rate is based on the revenue requirements associated with facilities operated at 200 kV and above of all transmission-owning entities that become participating transmission owners under the CAISO tariff. The transmission access charge methodology results in a cost shift from transmission owners, whose costs for existing transmission facilities at 200 kV and above are higher than that embedded in the uniform transmission access charge rate, to transmission owners with lower embedded costs for existing high voltage transmission, such as the Utility. The Utility's obligation for this cost differential, which is capped at $32 million per year during the 10-year transition period, is recovered in retail transmission rates.

Natural Gas

The Gas Accord

The Utility's authorized natural gas transmission and storage rates and associated revenue requirements from January 1, 2008 through December 31, 2010 have been set in accordance with the CPUC-approved settlement agreement known as the Gas Accord IV. On September 18, 2009, the Utility filed an application with the CPUC to establish the Utility's natural gas transmission and storage revenue requirements from January 1, 2011 through 2014 and to continue a majority of the terms and conditions of the Gas Accord IV. A decision on the Utility's application, known as the Gas Accord V, is expected by the end of 2010. A substantial portion of the authorized revenue requirements, primarily those costs allocated to core customers, would continue to be assured of recovery through balancing account mechanisms and/or fixed reservation charges. The Utility's ability to recover the remaining revenue requirements would continue to depend on throughput volumes, gas prices, and the extent to which non-core customers and other shippers contract for firm transmission services. This volumetric cost recovery risk associated with each function (backbone transmission, local transmission, and storage) is summarized below:

Backbone Transmission. The backbone transmission revenue requirement is recovered through a combination of firm two-part rates (consisting of fixed monthly reservation charges and volumetric usage charges) and as-available one-part rates (consisting only of volumetric usage charges). The mix of firm and as-available backbone services provided by the Utility continually changes. As a result, the Utility's recovery of its backbone transmission costs is subject to volumetric and price risk to the extent that backbone capacity is sold on an as-available basis. Core procurement entities (including core customers served by the Utility) are the primary long-term subscribers to backbone capacity. Core customers are allocated approximately 36% of the total backbone capacity on the Utility's system. Core customers pay approximately 72% of the costs of the backbone capacity that is allocated to them through fixed reservation charges.

Local Transmission. The local transmission revenue requirement is allocated approximately 71% to core customers and 29% to non-core customers. The Utility recovers the portion allocated to core customers through a balancing account, but the Utility's recovery of the portion allocated to non-core customers is subject to volumetric and price risk.

Storage. The storage revenue requirement is allocated approximately 71% to core customers, 12% to non-core storage service, and 17% to pipeline load balancing service. The Utility recovers the portion allocated to core customers through a balancing account, but the Utility's recovery of the portion allocated to non-core customers is subject to volumetric and price risk. The revenue requirement for pipeline load balancing service is recovered in backbone transmission rates and is subject to the same cost recovery risks described above for backbone transmission.

Biennial Cost Allocation Proceeding

Certain of the Utility's natural gas distribution costs and balancing account balances are allocated to customers in the CPUC's Biennial Cost Allocation Proceeding. This proceeding normally occurs every two years and is updated in the interim year for purposes of adjusting natural gas rates to recover from customers any under-collection, or refund to customers any over-collection, in the balancing accounts. Balancing accounts for gas distribution and other authorized expenses accumulate differences between authorized amounts and actual revenues.

Natural Gas Procurement

The Utility sets the natural gas procurement rate for core customers monthly, based on the forecasted costs of natural gas, core pipeline capacity and storage costs. The Utility reflects the difference between actual natural gas purchase costs and forecasted natural gas purchase costs in several natural gas balancing accounts, with under-collections and over-collections taken into account in subsequent monthly rates.

The Utility recovers the cost of gas (subject to the ratemaking mechanism discussed below), acquired on behalf of core customers, through its retail gas rates. The Utility is protected against after-the-fact reasonableness reviews of these gas procurement costs under the Core Procurement Incentive Mechanism ("CPIM"). Under the CPIM, the Utility's purchase costs for a fixed 12-month period are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas price indices at the points where the Utility typically purchases natural gas. Costs that fall within a tolerance band, which is 99% to 102% of the benchmark, are considered reasonable and are fully recovered in customers' rates. One-half of the costs above 102% of the benchmark are recoverable in customers' rates, and the Utility's customers receive in their rates 80% of any savings resulting from the Utility's cost of natural gas that is less than 99% of the benchmark. The shareholder award is capped at the lower of 1.5% of total natural gas commodity costs or $25 million. While this incentive mechanism remains in place, changes in the price of natural gas, consistent with the market-based benchmark, are not expected to materially impact net income. The Utility also has received CPUC approval for a long-term gas hedging program through 2011 on behalf of core customers. The costs of the hedging program are recovered directly from gas customers, outside the CPIM mechanism, and are subject only to a compliance review, not an after-the fact reasonableness review. (For more information, see Note 10: Derivatives and Hedging Activities, of the Notes to the Consolidated Financial Statements in the 2009 Annual Report).

In January 2010, the CPUC approved a joint settlement agreement among the Utility, the CPUC's Division of Ratepayer Advocates, and The Utility Reform Network to incorporate a portion of hedging costs for core customers into the Utility's CPIM. The settlement agreement has an initial term of seven years, through October 2017, which can be extended by agreement of the parties. As a result, the settlement agreement permits the Utility to develop and implement a sustained core hedging program.

Interstate and Canadian Natural Gas Transportation

The Utility's interstate and Canadian natural gas transportation agreements with third-party service providers are governed by tariffs that detail rates, rules, and terms of service for the provision of natural gas transportation services to the Utility on interstate and Canadian pipelines. United States tariffs are approved for each pipeline for service to all of its shippers, including the Utility, by the FERC in a FERC ratemaking review process, and the applicable Canadian tariffs are approved by the Alberta Utilities Commission and the National Energy Board. The Utility's agreements with interstate and Canadian natural gas transportation service providers are administered as part of the Utility's core natural gas procurement business. Their purpose is to transport natural gas from the points at which the Utility takes delivery of natural gas (typically in Canada and the southwestern United States) to the points at which the Utility's natural gas transportation system begins. For more information, see the discussion below under "Natural Gas Utility Operations — Interstate and Canadian Natural Gas Transportation Services Agreements."

Energy Efficiency, Public Purpose, and Other Programs

California law requires the CPUC to authorize certain levels of funding for electric and gas public purpose programs related to energy efficiency, low-income energy efficiency, research and development, and renewable energy resources. California law also requires the CPUC to authorize funding for the California Solar Initiative and other self-generation programs, as discussed below. Additionally, the CPUC has authorized funding for demand response programs.

For 2009, the CPUC authorized the Utility to collect revenue requirements of $751 million from electric customers to fund electric public purpose and other programs and $132 million from gas customers to fund natural gas public purpose and other programs. The CPUC is responsible for authorizing the programs, funding levels, and cost recovery mechanisms for the Utility's operation of these programs. The CEC administers both the electric and natural gas public interest research and development programs and the renewable energy program on a statewide basis. In 2009, the Utility transferred $82 million from its revenue requirements to the CEC for CEC-administered gas and electric programs.

Energy Efficiency Programs

The Utility's energy efficiency programs are designed to encourage the manufacture, design, distribution, and customer use of energy efficient appliances and other energy-using products. The CPUC authorized the Utility to collect revenue requirements of $479 million for 2009 gas and electric programs, including the CEC-administered programs. The CPUC has authorized the Utility to collect $1.3 billion of revenue requirements to fund its 2010-2012 programs, a 42% increase over 2006-2008 authorized funding levels. The CPUC has adopted a long-term energy efficiency strategic plan designed to encourage innovative market transformation activities, such as the pursuit of zero net energy buildings, in addition to traditional energy efficiency rebate programs.

The CPUC established an incentive ratemaking mechanism to encourage the California investor-owned utilities to promote energy efficiency and to meet the CPUC's energy savings goals. This incentive ratemaking mechanism applied to the utilities' 2006 through 2008 energy efficiency program cycles.

In accordance with this mechanism, the CPUC has awarded the Utility incentive revenues totaling $75 million through December 31, 2009 based on the energy savings achieved through implementation of the Utility's energy efficiency programs during the 2006 through 2008 program cycle. Consistent with the incentive award process previously adopted by the CPUC, the CPUC held back an additional $40.3 million of incentive revenues subject to verification of final energy savings and the completion of the true-up process in 2010.

It is uncertain what form of incentive ratemaking, if any, the CPUC will establish for energy efficiency programs in 2009 and later years. For more information, see the section of MD&A entitled "Regulatory Matters — Energy Efficiency Programs and Incentive Ratemaking" in the 2009 Annual Report.

Demand Response Programs

Demand response programs provide financial incentives and other benefits to participating customers to curtail on-peak energy use. On August 20, 2009, the CPUC approved the Utility's 2009-2011 demand response programs and authorized funding of $109 million. In addition, on February 14, 2008, the CPUC approved the Utility's multi-year air conditioning direct load control program and authorized funding of $179 million through June 1, 2011 to implement this program. Customers who enroll in this program will allow the Utility to remotely control the temperature settings of their central air conditioners to temporarily decrease their energy usage during local or system emergencies.

During 2006, the Utility began the installation of an advanced metering infrastructure, known as the SmartMeter™ program, for virtually all of the Utility's electric and gas customers. These meters enable the Utility to measure usage on an hourly basis for electricity and on a daily basis for natural gas, which can allow for demand-response rates to encourage customers to reduce energy consumption during peak demand periods, thus reducing peak period procurement costs. Advanced meters can record usage in time intervals and be read remotely. The Utility expects to complete the installation of the network infrastructure and advanced meters throughout its service territory by the end of 2011. The CPUC also has ordered the Utility to install advanced metering and billing systems to enable the Utility to implement "dynamic pricing" for electricity customers to encourage efficient energy consumption and cost-effective demand response by more closely aligning retail rates with the wholesale electricity market. "Dynamic pricing" includes rates that are based on critical peak prices and time of use. Customers may choose an alternate rate plan structure. The Utility is required to implement dynamic pricing by May 2010 for larger customers and by November 2011 for small and medium non-residential customers. The Utility has requested that the CPUC authorize the Utility to recover estimated costs of approximately $160 million to implement dynamic pricing, including approximately $32 million as an allowance for unforeseen costs the Utility may incur in connection with such a large and complex capital project. (See the discussion under the heading "Risk Factors" that appears in the MD&A section of the 2009 Annual Report.)

Self-Generation Incentive Program and California Solar Initiative

The Utility administers the self-generation incentive program ("SGIP") authorized by the CPUC to provide incentives to electricity customers who install certain types of clean or renewable distributed generation and energy storage resources that meet all or a portion of their onsite energy usage. The CPUC approved a budget for the SGIP of approximately $36 million in each of 2010 and 2011. The CPUC also approved the use of carryover funds through 2015. In late 2006, the CPUC established the California Solar Initiative ("CSI") to bring 1,940 MW of solar power on-line by 2017 in California and authorized the California investor-owned utilities to collect an additional $2.2 billion over the 2007 through 2016 period from their customers to fund customer incentives for the installation of retail solar energy projects to serve onsite load to meet this goal. Of the total amount authorized, the Utility has been allocated $946 million to fund customer incentives, research, development, and demonstration activities (with an emphasis on the demonstration of solar and solar-related technologies), and administration expenses. The California Legislature modified the CSI program to include participation of the California municipal utilities. The current overall goal of the CSI is to install 3,000 MW (through both investor-owned electric utilities and electric municipal utilities) through 2017.

Low-Income Energy Efficiency Programs and California Alternate Rates for Energy

The CPUC has authorized the Utility to collect approximately $417 million to support the Utility's energy efficiency programs for low-income and fixed-income customers over 2009 through 2011. The Utility also provides a discount rate called the California Alternate Rates for Energy ("CARE") for low-income customers. This rate subsidy is paid for by the Utility's other customers. The extent of the subsidy, during any given year, depends upon the number of customers participating in the program and their actual energy usage. In 2009, the amount of this subsidy was approximately $637 million, including avoided customer surcharges. The CPUC also authorized the Utility to recover approximately $28 million in administrative costs relating to the CARE subsidy over 2009 through 2011.

Environmental Matters

General

The Utility is subject to a number of federal, state and local laws and requirements relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of activities, including the following:

- the discharge of pollutants into the air, water, and soil;
- the transportation, handling, storage and disposal of spent nuclear fuel;
- the identification, generation, storage, handling, transportation, treatment, disposal, record keeping, labeling, reporting, remediation and emergency response in connection with hazardous and radioactive substances;
- the reporting and reduction of carbon dioxide ("CO2") and other GHG emissions; and
- the environmental impacts of land use, including endangered species and habitat protection.

The penalties for violation of these laws and requirements can be severe and may include significant fines, damages, and criminal or civil sanctions. These laws and requirements also may require the Utility, under certain circumstances, to interrupt or curtail operations. To comply with these laws and requirements, the Utility may need to spend substantial amounts from time to time to construct, acquire, modify, or replace equipment, acquire permits and/or emission allowances or other emission credits for facility operations and clean-up, or decommission waste disposal areas at the Utility's current or former facilities and at third-party sites where the Utility's wastes may have been disposed.

The Utility's estimated costs to comply with environmental laws and regulations are based on current estimates and assumptions that are subject to change. In addition, the Utility is likely to incur costs as it develops and implements strategies to mitigate the impact of its operations on the environment, including climate change and its foreseeable impact on the Utility's future operations. The actual amount of costs that the Utility will incur is subject to many factors, including changing laws and regulations, the ultimate outcome of complex factual investigations, evolving technologies, selection of compliance alternatives, the nature and extent of required remediation, the extent of the facility owner's responsibility, the availability of recoveries or contributions from third parties, and the development of market-based strategies to address climate change. Generally, the Utility has recovered the costs of complying with environmental laws and regulations in the Utility's rates, subject to reasonableness review. Environmental costs associated with the clean-up of sites that contain hazardous substances are subject to a special ratemaking mechanism described below under "Hazardous Waste Compliance and Remediation." In the future, the Utility's operations are likely to be affected by climate change. See the section of MD&A entitled "Environmental Matters" and "Risk Factors" in the 2009 Annual Report for a discussion of the operating, regulatory, and litigation risks posed by climate change and associated with the Utility's environmental compliance obligations.

Portland General

Portland General

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- *Power Costs.* In addition to price changes resulting from the general rate case process, the OPUC has approved the following mechanisms by which PGE can adjust retail customer prices to cover the Company's NVPC, which consists of direct and indirect costs of power and fuel less revenues from wholesale electricity sales:
  - Annual Power Cost Update Tariff. Under this tariff, customer prices are adjusted annually to reflect the latest forecast of NVPC. Such forecasts assume average regional hydro conditions (based on a 70-year regulation study covering the period 1928 - 1998) utilized in the Company's most recent general rate case, with no adjustments for updated hydro projections. An initial forecast, submitted to the OPUC by April 1 each year, is updated during the year and finalized in November. Based upon the final forecast, new prices, as approved by the OPUC, become effective at the beginning of the next calendar year; and AUT
  - Power Cost Adjustment Mechanism (PCAM). Customer prices can also be adjusted to reflect a portion of the difference between each year's forecasted NVPC included in prices and actual NVPC for the year. Under the PCAM, PGE is subject to a portion of the business risk or benefit associated with the difference between actual NVPC and that included in base prices. The PCAM utilizes an asymmetrical deadband within which PGE absorbs cost variances, with a 90/10 sharing of such variances between customers and the Company outside of the deadband. Annual results of the PCAM are subject to application of a regulated earnings test, with final determination of any customer refund or collection made by the OPUC through a public filing and review. For additional information, see the Results of Operations section of Item 7.-- "Management's Discussion and Analysis of Financial Condition and Results of Operations."
- *Renewable Energy* The 2007 Oregon Renewable Energy Act (the Act) established a Renewable Energy Standard (RES) which requires that PGE serve at least 5% of its retail load within the state from renewable resources from 2011 through 2014, 15% for 2015 through 2019, 20% for 2020 through 2024, and 25% in 2025 and subsequent years. PGE anticipates that it will meet the 2011 requirement of the Act with existing or currently planned renewable resources. Further, the Company expects that, with additional resources included in its currently proposed integrated resource plan, it will meet the 2015 requirement. It is anticipated that subsequent years' requirements will be met by the acquisition of additional renewable resources, as determined pursuant to the Company's integrated resource planning process. For additional information, see the Power Supply section in this Item 1.

  The Act also provides for the recovery in customer rates of all prudently incurred costs required to comply with the RES. Under a renewable adjustment clause (RAC) mechanism, PGE can recover the revenue requirement of new renewable resources and associated transmission that are not yet included in rates. Under the RAC, PGE submits a filing on April 1 of each year for new renewable resources being placed in service in the current year, with rates to become effective January 1st of the following year. In addition, the RAC provides for the deferral of eligible costs incurred prior to January 1st of the following year.

  For additional information, see the Legal, Regulatory and Environmental Matters discussion in the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Other ratemaking proceedings can involve charges or credits related to specific costs, programs, or activities, as well as the recovery or refund of deferred amounts recorded pursuant to specific OPUC authorization. Such amounts are generally collected from, or refunded to, retail customers through the use of supplemental tariffs.

Decoupling Mechanism—First year results of the decoupling mechanism, which became effective on February 1, 2009, resulted in an approximate $6.8 million future refund to customers, as weather adjusted use per customer exceeded that included in PGE's 2009 General Rate Case. Such refunds, included in Regulatory liabilities as of December 31, 2009, will begin June 1, 2010, subject to review and approval by the OPUC.

Power Cost Adjustment Mechanism

PGE is subject to a power cost adjustment mechanism (PCAM) as approved by the OPUC. Pursuant to the PCAM, the Company can adjust future prices to reflect a portion of the difference between each year's forecasted NVPC included in prices (baseline) and actual NVPC. PGE is subject to a portion of the business risk or benefit associated with the difference between actual NVPC and that included in base prices by application of an asymmetrical deadband within which PGE absorbs cost increases or decreases, with a 90/10 sharing of costs and benefits between customers and the Company, respectively, outside of the deadband. Any customer refund or collection is also subject to a regulated earnings test. A refund will occur only to the extent that it results in PGE's actual return on equity (ROE) for that year being no less than 1% above the Company's latest authorized ROE. A collection will occur only to the extent that it results in PGE's actual ROE for that year being no greater than 1% below the Company's last authorized ROE. PGE's authorized ROE was 10.0% for 2009 and 10.1% for 2008. A final determination of any customer refund or collection is made by the OPUC through an annual public filing and review.

PGE estimates and records amounts related to the PCAM on a quarterly basis during the year. If the projected difference between baseline and actual NVPC for the year exceeds the established deadband, and if forecasted

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PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

earnings exceed the level required by the regulated earnings test, a regulatory liability is recorded for any future amount payable to retail customers, with offsetting amounts recorded to Purchased power and fuel expense. If the difference is below the lower end of the deadband, a regulatory asset is recorded for any future amount due from retail customers.

For 2009, the deadband ranged from $15 million below, to $29 million above, the baseline. Although PGE's actual NVPC as determined pursuant to the PCAM for 2009 exceeded the baseline by $22 million, it was within the established deadband and, accordingly, no customer collection was recorded in 2009. A final determination regarding the 2009 PCAM results will be made by the OPUC through a public filing and review in 2010.

For 2008, the deadband ranged from $14 million below, to $28 million above, the baseline. PGE's actual NVPC as determined under the PCAM for 2008 was less than the established baseline by approximately $31 million. No regulatory liability was recorded in 2008 for this amount however, as PGE's earnings did not attain the level required under the PCAM's regulated earnings test.

Energy Efficiency Funding –Oregon's electricity restructuring law also provides for a "public purpose charge" to fund cost-effective energy efficiency measures, new renewable energy resources, and weatherization measures for low-income housing. This charge, equal to 3% of retail revenues, is collected from customers and remitted to the Energy Trust of Oregon (ETO) and other agencies for administration of these programs. In 2009 and 2008, approximately $48 million and $47 million, respectively, were billed to customers for this charge.

PGE also remits to the ETO amounts collected under an Energy Efficiency Adjustment tariff to fund additional energy efficiency measures. The tariff, which became effective on June 1, 2008, included an approximate 1% charge for eligible customers, providing about $14 million annually for measures that enable customers to reduce their energy use. Effective January 1, 2010, the charge was increased to approximately 1.5%, which is expected to provide about $21 million annually

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Decoupling—Pursuant to OPUC authorization in PGE's most recent general rate case (2009 General Rate Case), the Company is deferring, for later ratemaking treatment, amounts associated with a new decoupling mechanism. The mechanism is intended to provide for recovery of reduced revenues resulting from a reduction in electricity sales attributable to energy efficiency and conservation efforts by residential and certain commercial customers. It also provides for customer refunds if weather adjusted use per customer exceeds that approved in the rate case. For 2009, PGE accrued a refund to customers of $6.8 million, as weather adjusted use per customer for the year exceeded that approved in the rate case.

SCANA Corp.

SCANA

Fuel Cost Recovery Procedures

In June 2009, SCE&G filed a request with the SCPSC for approval of certain demand reduction and energy efficiency programs (DSM programs). SCE&G has requested the establishment of an annual rider to allow recovery of the costs and lost net margin revenue associated with DSM programs along with an incentive for investing in such programs. The SCPSC has scheduled a hearing on SCE&G's request for April 1, 2010.

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The SCPSC's fuel cost recovery procedure determines the fuel component in SCE&G's retail electric base rates annually based on projected fuel costs for the ensuing 12-month period, adjusted for any over-collection or under-collection from the preceding 12-month period. The statutory definition of fuel costs includes certain variable environmental costs, such as ammonia, lime, limestone and catalysts consumed in reducing or treating emissions. The definition also includes the cost of emission allowances used for sulfur dioxide, nitrogen oxide, mercury and particulates. SCE&G may request a formal proceeding at any time should circumstances dictate such a review. In April 2009, the SCPSC approved a settlement agreement between SCE&G and the South Carolina Office of Regulatory Staff (ORS) and others, whereby SCE&G increased the fuel cost portion of its electric rates effective with the first billing cycle of May 2009. As part of the settlement, SCE&G agreed to spread the recovery of then under- collected fuel costs over a three-year period ending April 2012. SCE&G is allowed to collect interest on the deferred balance.

SCE&G's tariffs include a purchased gas adjustment (PGA) clause that provides for the recovery of actual gas cost incurred, including costs related to hedging natural gas purchasing activities. SCE&G's rates are calculated using a methodology which adjusts the cost of gas monthly based on a twelve-month rolling average.

PSNC Energy is subject to a Rider D rate mechanism which allows it to recover, in any manner authorized by the NCUC, losses on negotiated gas and transportation sales. The Rider D rate mechanism also allows PSNC Energy to recover from customers all prudently incurred gas costs and certain uncollectible expenses related to gas cost.

PSNC Energy's rates are established using a benchmark cost of gas approved by the NCUC, which may be adjusted periodically to reflect changes in the market price of natural gas. PSNC Energy revises its tariffs with the NCUC as necessary to track these changes, and accounts for any over- or under-collections of the delivered cost of gas in its deferred accounts for subsequent rate consideration. The NCUC reviews PSNC Energy's gas purchasing practices annually.

RATE MATTERS

For a discussion of the impact of various rate matters, see the Regulatory Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G, and Note 2 to the consolidated financial statements for SCANA and SCE&G.

SCE&G's gas rate schedules for its residential, small commercial and small industrial customers include a Weather Normalization Adjustment (WNA) approved by the SCPSC which is in effect for bills rendered for billing cycles in November through April. The WNA increases tariff rates if weather is warmer than normal and decreases rates if weather is colder than normal. The WNA does not change the seasonality of gas revenues, but reduces fluctuations in revenues and earnings caused by abnormal weather.

PSNC Energy is authorized by the NCUC to utilize a CUT, a rate decoupling mechanism that breaks the link between revenues and the amount of natural gas sold. The CUT allows PSNC Energy to periodically adjust its base rates for residential and commercial customers based on average per customer consumption whether impacted by weather or other factors.

CUT	Customer Usage Tracker

Sempra Energy

SEMPRA

Hazardous Substances

In 1994, the CPUC approved the Hazardous Waste Collaborative mechanism, allowing California's IOUs to recover hazardous waste cleanup costs for certain sites, including those related to certain Superfund sites. This mechanism permits the Sempra Utilities to recover in rates 90 percent of hazardous waste cleanup costs and related third-party litigation costs, and 70 percent of the related insurance-litigation expenses. In addition, the Sempra Utilities have the opportunity to retain a percentage of any recoveries from insurance carriers and other third parties to offset the cleanup and associated litigation costs not recovered in rates.

At December 31, 2009, we had accrued estimated remaining investigation and remediation liabilities of $1.5 million at SDG&E and $27.9 million at SoCalGas, both related to hazardous waste sites for which the Hazardous Waste Collaborative mechanism authorizes us to recover 90 percent of the costs. The accruals include costs for numerous locations, most of which had been manufactured-gas plants. This estimated cost excludes remediation costs of $5.9 million associated with SDG&E's former fossil-fuel power plants and other locations for which the cleanup costs are not being recovered in rates. We believe that any costs not ultimately recovered through rates, insurance or other means will not have a material adverse effect on our consolidated results of operations or financial position.

We record estimated liabilities for environmental remediation when amounts are probable and estimable. In addition, we record amounts authorized to be recovered in rates under the Hazardous Waste Collaborative mechanism as regulatory assets.

Sempra Utilities Revenues

Sempra Utilities revenues are comprised of natural gas revenues at SDG&E and SoCalGas, and electric revenues at SDG&E. Intercompany revenues included in the separate revenues of each utility are eliminated in the Sempra Energy Consolidated Statements of Operations.

The current regulatory framework permits the cost of natural gas purchased for core customers (primarily residential and small commercial and industrial customers) to be passed on to customers substantially as incurred. However, SoCalGas' Gas Cost Incentive Mechanism (GCIM) provides SoCalGas the opportunity to share in the savings and/or costs from buying natural gas for its core customers at prices below or above market-based monthly benchmarks. This mechanism permits full recovery of costs incurred when average purchase costs are within a price range around a monthly benchmark price. Any higher costs incurred or savings realized outside this range are shared between the core customers and SoCalGas. Through March 31, 2008, when SoCalGas assumed the purchasing for SDG&E's core customer natural gas requirements on a combined portfolio basis, SDG&E had a similar incentive mechanism that allowed cost sharing. We provide further discussion in Notes 1 and 16 of the Notes to Consolidated Financial Statements.

GENERAL RATE CASE (GRC)

The CPUC uses a general rate case proceeding to prospectively set rates sufficient to allow the Sempra Utilities to recover their reasonable cost of operations and to provide the opportunity to realize an acceptable rate of return on their investment. The Sempra Utilities are scheduled to file their next rate case with the CPUC with a 2012 test year.

In November 2009, SDG&E and SoCalGas, jointly with the Division of Ratepayer Advocates (DRA), a division of the CPUC representing the interests of customers, filed petitions with the CPUC to delay the filing of SDG&E's and SoCalGas' next GRC applications by one year. If approved by the CPUC, both SDG&E and SoCalGas would file their next GRC application in late 2011 for test year 2013. The petitions propose methodologies to determine the 2012 revenue requirements for each company which would result in SDG&E and SoCalGas receiving an increase of no less than approximately $45 million and $55 million, respectively, in authorized margin, or three percent, above the 2011 authorized margin. The parties also agreed, among other things, to allow the Sempra Utilities to recover the increase, as deemed reasonable, in their annual excess liability insurance premiums in 2012, primarily due to the coverage for wildfire claims. In December 2009, The Utility Reform Network, UCAN and Aglet Consumer Alliance filed a joint response opposing the requested increase.

In February 2010, due to the lack of progress by the CPUC in responding to the joint request to delay the GRC filings by one year, SDG&E and SoCalGas filed with the CPUC to withdraw the request for delay. If the withdrawal requests are approved by the CPUC, SDG&E and SoCalGas will each file in the third quarter of 2010 a Notice of Intent to file a GRC with a 2012 test year.

Operational Incentives

The CPUC has established operational incentive mechanisms that have been based on measurements of safety, reliability and customer satisfaction. The 2008 GRC proposed modified performance measures for customer satisfaction for both SDG&E and SoCalGas, and electric reliability for SDG&E. The Sempra Utilities filed responses in September 2008 rejecting the electric reliability and customer satisfaction measures. As a result, effective in 2008, the Sempra Utilities are no longer eligible for awards or subject to penalties for electric reliability and customer satisfaction.

The Sempra Utilities plan to submit their employee safety results and incentive awards claims in May 2010 for performance in 2009.

Energy Efficiency and Demand Side Management

The CPUC established incentive mechanisms that are based on the effectiveness of energy efficiency and demand side management programs. The CPUC-approved energy efficiency awards in 2008 were net of a holdback of 65 percent. In May 2009, SDG&E and SoCalGas filed a partial party settlement agreement regarding the appropriate method to determine incentive awards for the 2006 – 2008 program period. The settlement, if approved by the CPUC, would have resulted in 1) awards of $10.7 million for SDG&E and $12.5 million for SoCalGas; and 2) upon conclusion of the CPUC's assessment and audit process, awards of up to $11.6 million for SDG&E and $9.5 million for SoCalGas for the remaining holdback amounts. The CPUC issued a decision in December 2009 rejecting the settlement agreement and instead awarding $0.3 million and $2.1 million to SDG&E and SoCalGas, respectively. The decision held back 35 percent of the program incentive awards pending a final true-up in 2010. In the first quarter of 2010, the Sempra Utilities expect to file a petition for modification of the December 2009 decision to address errors identified in the decision.

In September 2009, the CPUC approved the Sempra Utilities' energy efficiency programs through 2012 and will use a similar annual review process to determine any utility incentive awards. The CPUC is also considering future enhancements to the overall incentive award process and mechanism, and a draft decision on possible changes will likely be issued in the first half of 2010.

Natural Gas Procurement

The Sempra Utilities procure natural gas on behalf of their core natural gas customers. The CPUC has established incentive mechanisms to allow the Sempra Utilities the opportunity to share in the savings and/or costs from buying natural gas for its core customers at prices below or above market-based monthly benchmarks. Beginning April 1, 2008, the SDG&E and SoCalGas core natural gas supply portfolios were combined, and SoCalGas now procures natural gas for SDG&E's core natural gas customers' requirements. All SDG&E assets associated with its core natural gas supply portfolio were transferred or assigned to SoCalGas. Accordingly, SDG&E's incentive mechanism for natural gas procurement awards or penalties ended as of the effective date of the combination of the core natural gas supply portfolios, and SoCalGas' gas cost incentive mechanism (GCIM) is applied on the combined portfolio basis going forward.

In January 2010, the CPUC approved a SoCalGas GCIM award of $12 million for its procurement activities in the 12-month period ended March 31, 2009, which will be recorded in the first quarter of 2010.

Unbundled Natural Gas Storage and System Operator Hub Services

The CPUC has established a revenue sharing mechanism which provides for the sharing between ratepayers and SoCalGas of the net revenues generated by SoCalGas' unbundled natural gas storage and system operator hub services. In 2008, the CPUC adopted an uncontested settlement agreement in Phase I of the Sempra Utilities' Biennial Cost Allocation Proceeding (BCAP) which, among other things, established that the annual net revenues (revenues less allocated service costs) be shared on a graduated basis, as follows:

- the first $15 million of net revenue to be shared 90 percent ratepayer/10 percent shareholders;
- the next $15 million of net revenue to be shared 75 percent ratepayer/25 percent shareholders;
- all additional net revenues to be shared evenly between ratepayer and shareholders; and
- the maximum total annual shareholder-allocated portion of the net revenues cannot exceed $20 million.

COST OF CAPITAL

A cost of capital proceeding determines the Sempra Utilities' authorized capital structure and the authorized rate of return that the Sempra Utilities may earn on their electric and natural gas distribution and electric generation assets.

SoCalGas

SoCalGas' authorized return on equity (ROE) is 10.82 percent and its authorized return on rate base (ROR) is 8.68 percent. These rates continue to be effective until market interest rate changes are large enough to trigger an automatic adjustment or until the CPUC orders a periodic review. SoCalGas' current authorized capital structure is

- 48.0 percent common equity
- 6.4 percent preferred equity
- 45.6 percent long-term debt

In July 2009, the CPUC denied SoCalGas' petition seeking to suspend its cost of capital Market Index Capital Adjustment Mechanism (MICAM). SoCalGas believes that the index used for the MICAM does not provide a strong correlation with utility risks and that further government actions to manage interest rates could increase the likelihood of triggering the MICAM in the future. Although the MICAM did not trigger in 2009, SoCalGas may eventually seek a change in the MICAM benchmarks to defer any resultant change in its cost of capital and propose a more indicative index associated with the natural gas distribution business.

SDG&E

SDG&E's authorized ROE is 11.10 percent and its authorized ROR is 8.40 percent. SDG&E's current authorized capital structure is

- 49.00 percent common equity
- 5.75 percent preferred equity
- 45.25 percent long-term debt

In January 2010, the CPUC approved SDG&E's and the DRA's joint petition to delay SDG&E's next scheduled cost of capital application for two years. With this approval, SDG&E's next cost of capital application is scheduled to be filed in April 2012, consistent with the schedule for cost of capital applications for each of Edison and Pacific Gas and Electric (PG&E).

ADVANCED METERING INFRASTRUCTURE

SDG&E

In April 2007, the CPUC approved SDG&E's request to install advanced meters with integrated two-way communications functionality, including electric remote disconnect and home area network capability. SDG&E estimates expenditures for this project of $572 million (including approximately $500 million in capital investment). This project involves replacing approximately 1.4 million electric meters and 850,000 natural gas meters throughout SDG&E's service territory. SDG&E began mass installation of the advanced meters in March 2009, and is on schedule to complete the project by the end of 2011.

SoCalGas

In September 2008, SoCalGas filed an application with the CPUC for approval to upgrade approximately six million natural gas meters with an advanced metering infrastructure (AMI) at an estimated cost of $1.1 billion (including approximately $900 million in capital investment). The administrative law judge's (ALJ) preliminary decision and an assigned commissioner's alternate decision (AD) were both issued in February 2010. While the ALJ draft decision finds a gas-only AMI system is consistent with the state's energy policy goals and that the AMI system is technically feasible, the ALJ draft decision finds that the gas-only AMI system is not cost effective. The AD approves the project and finds that the proposal provides reasonable assurance that the project can be cost effective for ratepayers, provided that adequate safeguards are put in place. We expect a final CPUC decision in mid-2010. If approved, installation of the meters is expected to begin in 2012 and continue through 2017.

2007 WILDFIRES COST RECOVERY

SDG&E filed an application with the CPUC in March 2009 seeking to recover the incremental cost incurred to replace and repair company facilities under CPUC jurisdiction damaged by the October 2007 wildfires. This application was filed in accordance with the CPUC rules governing incremental costs incurred as a result of a declared emergency or catastrophic event. The DRA filed a protest to SDG&E's request for recovery of the incremental costs, requesting that the CPUC stay the proceeding until completion of the fire investigations, which we describe in Note 17. SDG&E and the DRA have reached an agreement in principle regarding the cost recovery request which, if approved by the CPUC, would result in SDG&E recovering $43 million. A formal settlement agreement is being finalized, but no specific filing date has been established.

SDG&E also incurred $30.1 million of incremental costs for the replacement and repair of company facilities under FERC jurisdiction, which are currently being recovered in SDG&E's electric transmission rates.

In regard to the 2007 wildfire litigation discussed in Note 17, if SDG&E's liability were to exceed the remaining amounts recoverable from its insurers, SDG&E will file with the FERC and the CPUC for recovery of the excess costs from utility customers. SDG&E is continuing to evaluate the likelihood, amount and timing of any such recoveries.

INSURANCE COST RECOVERY

SDG&E filed an application with the CPUC in August 2009 seeking authorization to recover higher liability insurance premium and deductible expenses which SDG&E began incurring on July 1, 2009. Evidentiary hearings are scheduled for April 2010 and a final CPUC decision is expected by the end of 2010. SDG&E made the filing under the CPUC's rules allowing utilities to seek recovery of significant cost increases resulting from unforeseen circumstances. SDG&E is requesting a $29 million revenue requirement for the 2009/2010 policy period for the incremental increase in its liability and wildfire insurance premium costs above what is currently authorized in rates. The CPUC's rules allow a utility to recover costs that meet certain criteria, subject to a $5 million deductible per event. Through December 31, 2009, SDG&E has expensed $15 million (pretax) of incremental insurance premiums associated with this wildfire coverage.

FUTURE EXCESS CLAIMS COST RECOVERY

SDG&E and SoCalGas filed an application with the CPUC in August 2009 proposing a new mechanism for the full recovery of future wildfire-related claims, litigation and insurance premium expenses that are in excess of amounts authorized by the CPUC for recovery in rates. The filing was made jointly with Edison and PG&E. The utilities are asking the CPUC to approve their joint request by the second quarter of 2010. Several parties protested the request and a proceeding schedule has not yet been established.

GREENHOUSE GAS REGULATION

Legislation was enacted in 2006, including California Assembly Bill 32 (AB 32) and California Senate Bill 1368, mandating reductions in greenhouse gas emissions. The CARB is the lead agency in developing a plan to meet these requirements and is in the process of developing rules and market mechanisms that will be implemented on January 1, 2012. The CPUC and CEC are also in the process of making recommendations to the CARB regarding the rules that should apply for the electricity and natural gas sectors. The CARB's formal AB 32 Scoping Plan was adopted in December 2008.

The U.S. Environmental Protection Agency (EPA) has announced that it will complete a review of the national ambient air quality standards by the end of 2011 for ozone (nitrogen oxide and volatile organic chemicals), particulate matter, carbon monoxide, nitrogen dioxide, sulfur dioxide, and lead. This review could result in more stringent emissions limits on fossil-fired electric generating plants.

These legislative mandates could affect costs and growth at the Sempra Utilities and at Sempra Generation's power plants. Any cost impact at the Sempra Utilities is expected to be recoverable through rates. As discussed in Note 17 under "Environmental Issues," compliance with this and similar legislation could adversely affect Sempra Generation. However, such legislation could also have a positive impact on Sempra Generation because of an increasing preference for natural gas and renewables for electric generation, as opposed to other sources.

Southern Co.

Southern Co.

Rate Matters

Rate Structure and Cost Recovery Plans

The rates and service regulations of the traditional operating companies are uniform for each class of service throughout their respective service areas. Rates for residential electric service are generally of the block type based upon kilowatt-hours used and include minimum charges. Residential and other rates contain separate customer charges. Rates for commercial service are presently of the block type and, for large customers, the billing demand is generally used to determine capacity and minimum bill charges. These large customers' rates are generally based upon usage by the customer and include rates with special features to encourage off-peak usage. Additionally, Alabama Power, Gulf Power, and Mississippi Power are generally allowed by their respective state PSCs to negotiate the terms and cost of service to large customers. Such terms and cost of service, however, are subject to final state PSC approval.

Fuel and net purchased energy costs are recovered through specific fuel cost recovery provisions at the traditional operating companies. These fuel cost recovery provisions are adjusted to reflect increases or decreases in such costs as needed. Gulf Power's and Mississippi Power's fuel cost recovery provisions are adjusted annually to reflect increases or decreases in such costs. Georgia Power filed for an adjustment to its fuel cost recovery rate on December 15, 2009. If approved by the Georgia PSC, the adjustment would be effective on April 1, 2010. Alabama Power's fuel clause is adjusted as required. Revenues are adjusted for differences between recoverable costs and amounts actually recovered in current rates.

Approved environmental compliance and storm damage costs are recovered at Alabama Power and Mississippi Power through cost recovery provisions approved by their respective state PSCs. Within limits approved by their respective PSCs, these rates are adjusted to reflect increases or decreases in such costs as required.

Georgia Power's environmental compliance costs are recovered in base rates. Under the 2007 retail rate plan, an environmental compliance cost recovery tariff was implemented effective January 1, 2008 to allow recovery of environmental costs mandated by state and federal regulation. See Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters — Georgia Power — Retail Rate Plans" and Georgia Power under "Retail Regulatory Matters — Rate Plans" in Item 8 herein for additional information.

See "Integrated Resource Planning" herein for a discussion of Georgia PSC certification of new demand-side or supply-side resources for Georgia Power. In addition, see MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "Construction — Nuclear" of Georgia Power in Item 7 herein and Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters — Georgia Power — Nuclear Construction" and Georgia Power under "Construction — Nuclear" in Item 8 herein for a discussion of the Georgia Nuclear Financing Act and the Georgia PSC certification of Plant Vogtle Units 3 and 4, which allow Georgia Power to recover financing costs for construction of the new nuclear units during the construction period beginning in 2011.

Alabama Power recovers the cost of certificated new plant and purchased power capacity through cost recovery provisions which are approved annually. Gulf Power files a rate clause request annually with the Florida PSC to recover costs associated with purchased power capacity, energy conservation, and environmental compliance. Revenues are adjusted for differences between recoverable costs and amounts actually recovered in current rates.

See MANAGEMENT'S DISCUSSION AND ANALYSIS — FUTURE EARNINGS POTENTIAL — "PSC Matters" of Southern Company and each of the traditional operating companies in Item 7 herein and Note 3 to the financial statements of Southern Company under "Retail Regulatory Matters" and Note 3 to the financial statements of each of the traditional operating companies under "Retail Regulatory Matters" in Item 8 herein for a discussion of rate matters. Also, see Note 1 to the financial statements of Southern Company and each of the traditional operating companies in Item 8 herein for a discussion of recovery of fuel costs, storm damage costs, and environmental compliance costs through rates.

Fuel Cost Recovery

Alabama Power has established fuel cost recovery rates under an energy cost recovery clause (Rate ECR) approved by the Alabama PSC Rates are based on an estimate of future energy costs and the current over or under recovered balance. In June 2007, the Alabama PSC approved Alabama Power's request to increase the retail energy cost recovery rate to 3.100 cents per kilowatt hour (KWH), effective with billings beginning July 2007. In October 2008, the Alabama PSC approved an increase in Alabama Power's Rate ECR factor to 3.983 cents per KWH effective with billings beginning October 2008. On June 2, 2009, the Alabama PSC approved a decrease in Alabama Power's Rate ECR factor to 3 733 cents per KWH for billings beginning June 9, 2009 On December 1, 2009, the Alabama PSC approved a decrease in Alabama Power's Rate ECR factor to 2.731 cents per KWH for billings beginning January 2010 through December 2011. The Alabama PSC further approved an additional reduction in the Rate ECR factor of 0.328 cents per KWH for the billing months of January 2010 through December 2010 resulting in a Rate ECR factor of 2 403 cents per KWH for such 12-month period. For billing months beginning January 2012, the Rate ECR factor shall be 5 910 cents per KWH, absent a contrary order by the Alabama PSC Rate ECR revenues, as recorded on the financial statements, are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates Accordingly, the approved decreases in the Rate ECR factor will have no significant effect on Southern Company's net income, but will decrease operating cash flows related to fuel cost recovery in 2010 when compared to 2009. As of December 31, 2009, Alabama Power had an over recovered fuel balance of approximately $200 million, of which approximately $22 million is included in other regulatory liabilities, deferred in the balance sheets. Alabama Power, along with the Alabama PSC, will continue to monitor the over recovered fuel cost balance to determine whether an additional adjustment to billing rates is required

Fuel Cost Recovery

Georgia Power has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved increases in Georgia Power's total annual billings of approximately $383 million effective March 1, 2007 and approximately $222 million effective June 1, 2008. On December 15, 2009, Georgia Power filed for a fuel cost recovery increase with the Georgia PSC On February 22, 2010, Georgia Power, the Georgia PSC Public Interest Advocacy Staff, and three customer groups entered into a stipulation to resolve the case, subject to approval by the Georgia PSC (the Stipulation) Under the terms of the Stipulation, Georgia Power's annual fuel cost recovery billings will increase by approximately $425 million In addition, Georgia Power will implement an interim fuel rider, which would allow Georgia Power to adjust its fuel cost recovery rates prior to the next fuel case if the under recovered fuel balance exceeds budget by more than $75 million Georgia Power is required to file its next fuel case by March 1, 2011 The Georgia PSC is scheduled to vote on the Stipulation on March 11, 2010 with the new fuel rates to become effective April 1, 2010 The ultimate outcome of this matter cannot be determined at this time.

As of December 31, 2009, Georgia Power's under recovered fuel balance totaled approximately $665 million, which if the Stipulation is approved, Georgia Power will recover over 32 months beginning April 1, 2010 Therefore, approximately $373 million of the under recovered regulatory clause revenues for Georgia Power is included in deferred charges and other assets at December 31, 2009.

Fuel cost recovery revenues as recorded in the financial statements are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates Accordingly, a change in the billing factor has no significant effect on Southern Company's revenues or net income, but does impact annual cash flow

The Florida Legislature has adopted legislation that allows a utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. The legislation is discussed in Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery." Substantially all of the costs for the Clean Air Act and other new environmental legislation discussed below are expected to be recovered through the environmental cost recovery clause.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known sites Included in this amount are costs associated with remediation of the Company's substation sites. These projects have been approved by the Florida PSC for recovery through the environmental cost recovery clause; therefore, there is no impact to the Company's net income as a result of these liabilities The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

PSC Matters

General

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation, and demand side management programs, and the costs of compliance with environmental laws and regulations Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates

On November 2, 2009, the Florida PSC approved the Company's annual rate requests for its purchased power capacity, energy conservation, and environmental compliance cost recovery factors for 2010 On December 1, 2009, the Florida PSC approved the Company's annual rate request for its 2010 fuel cost recovery factor, which includes both fuel and purchased energy cost. The net effect of the approved changes to the Company's cost recovery factors for 2010 is a 3.9% rate increase for residential customers using 1,000 KWHs per month. Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changing the billing factor has no significant effect on the Company's revenues or net income, but does impact annual cash flow See Notes 1 and 3 to the financial statements under "Revenues" and "Retail Regulatory Matters – Fuel Cost Recovery," respectively

Fuel Cost Recovery

The Company petitions for fuel cost recovery rates to be approved by the Florida PSC on an annual basis. At December 31, 2009 and 2008, the under recovered balance was $2.4 million and $96 7 million, respectively. The change in 2009 was primarily due to an increase in the 2009 fuel cost recovery factors and resulting revenue collected in the period and a higher percentage of natural gas-fired generation which cost less than projected. The Company continuously monitors the over or under recovered fuel cost balance in light of the inherent variability in fuel costs If the projected fuel cost over or under recovery exceeds 10% of the projected fuel revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the fuel cost recovery factor is being requested.

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Purchased Power Capacity Recovery

The Florida PSC allows the Company to recover its costs for capacity purchased from other power producers under power purchase agreements (PPAs) through a separate cost recovery component or factor in the Company's retail energy rates Like the other specific cost recovery factors included in the Company's retail energy rates, the rates for purchased capacity are set annually on a calendar year basis When the Company enters into a new PPA, it is reviewed and approved by the Florida PSC for cost recovery purposes As of December 31, 2009 and 2008, the Company had an over recovered purchased power capacity balance of approximately $1.5 million and $0.3 million, respectively, which is included in other regulatory liabilities, current in the balance sheets.

In March 2009, the Company entered into a PPA (the Agreement) with Shell Energy North America (US), L P (Shell) conditioned on subsequent review and approval of the Company's participation by the Florida PSC. The Florida PSC approved the Agreement through an order that became final in October 2009. As a result, the Agreement became effective on November 1, 2009. The Agreement will terminate on May 24, 2023, unless terminated earlier in accordance with its terms. Under the terms of the Agreement, the Company will be entitled to all of the capacity and energy from an approximately 885 MW combined cycle power plant (the Plant) located in Autauga County, Alabama that is owned and operated by Tenaska Alabama II Partners, L.P. (Tenaska) Shell is entitled to all of the capacity and energy from the Plant under a 20-year Energy Conversion Agreement between Shell and Tenaska that expires on May 24, 2023 Payments under the Agreement will be material. However, these costs have been approved by the Florida PSC for recovery through the Company's fuel clause and purchased power capacity clause; therefore, no material impact is expected on the Company's net income. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 7 to the financial statements under "Fuel and Purchased Power Commitments" for additional information

Environmental Cost Recovery

In August 2007, the Florida PSC voted to approve a stipulation among the Company, the Office of Public Counsel, and the Florida Industrial Power Users Group regarding the Company's plan for complying with certain federal and state regulations addressing air quality The Company's environmental compliance plan as filed in March 2007 contemplated implementation of specific projects identified in the plan from 2007 through 2018. The stipulation covers all elements of the current plan that are scheduled to be implemented in the 2007 through 2011 timeframe. On April 1, 2009, the Company filed an update to the plan, which was approved by the Florida PSC on November 2, 2009 The Florida PSC acknowledged that the costs associated with the Company's CAIR and Clean Air Visibility Rule compliance plans are eligible for recovery through the environmental cost recovery clause. Annually, the Company seeks recovery of projected costs including any true-up amounts from prior periods. At December 31, 2009 and 2008, the over recovered environmental balance was approximately $11.7 million and $71 thousand, respectively, which is included in other regulatory liabilities, current in the balance sheets See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein, Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery," and Note 7 to the financial statements under "Construction Program" for additional information.

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Limestone Commitments

As part of the Company's program to reduce sulfur dioxide emissions from certain of its coal plants, the Company has entered into various long-term commitments for the procurement of limestone to be used in flue gas desulfurization equipment Limestone contracts are structured with tonnage minimums and maximums in order to account for fluctuations in coal burn and sulfur content. The Company has a minimum contractual obligation of 0 8 million tons equating to approximately $67.7 million, through 2019 Estimated expenditures (based on minimum contracted obligated dollars) over the next five years are $6 0 million in 2010, $6 2 million in 2011, $6 3 million in 2012, $6.5 million in 2013, and $6 7 million in 2014. Limestone costs are recovered through the environmental cost recovery clause.

Fuel and Purchased Power Commitments

To supply a portion of the fuel requirements of the generating plants, the Company has entered into various long-term commitments for the procurement of fossil fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments Coal commitments include forward contract purchases for sulfur dioxide and nitrogen oxide emissions allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery, amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2009. Also, the Company has entered into various long-term commitments for the purchase of capacity, electricity, and transmission The energy-related costs associated with PPAs are recovered through the fuel cost recovery clause The capacity-related costs associated with PPAs are recovered through the purchased power capacity cost recovery clause

Fuel Cost Recovery

The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. The Company is required to file for an adjustment to the retail fuel cost recovery factor annually; such filing occurred in November 2009 The Mississippi PSC approved the retail fuel cost recovery factor on December 15, 2009, with the new rates effective in January 2010. The retail fuel cost recovery factor will result in an annual decrease in an amount equal to 11.3% of total 2009 retail revenue At December 31, 2009, the amount of over recovered retail fuel costs included in the balance sheets was $29.4 million compared to $36.0 million under recovered at December 31, 2008. The Company also has a wholesale Municipal and Rural Associations (MRA) and a Market Based (MB) fuel cost recovery factor. Effective January 1, 2010, the wholesale MRA fuel rate decreased, resulting in an

Miss PSC

(e) Recovered through the ad valorem tax adjustment clause over a 12-month period beginning in April of the following year

The Alabama PSC has also approved a rate mechanism that provides for adjustments to recognize the cost of placing new generating facilities in retail service and for the recovery of retail costs associated with certificated power purchase agreements (PPAs) under a Rate Certificated New Plant (Rate CNP). There was no adjustment to Rate CNP in April 2007, 2008, or 2009. Effective April 2010, Rate CNP will be reduced approximately $70 million annually, primarily due to the expiration on May 31, 2010 of the PPA with Southern Power covering the capacity of Plant Harris Unit 1 Rate CNP also allows for the recovery of Alabama Power's retail costs associated with environmental laws, regulations, or other such mandates. The rate mechanism is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on invested capital. Retail rates increased approximately 2.4% in January 2008 and 0.6% in January 2007 due to environmental costs. In October 2008, Alabama Power agreed to defer collection during 2009 of any increase in rates under this portion of Rate CNP which permits recovery of costs associated with environmental laws and regulations until 2010. The deferral of the retail rate adjustments had an immaterial impact on annual cash flows, and had no significant effect on Southern Company's revenues or net income in 2009. On December 1, 2009, Alabama Power made its Rate CNP environmental submission to the Alabama PSC of projected data for calendar year 2010 The Rate CNP environmental increase for 2010 is 4 3%, or $195 million annually, based upon projected billings. Under the terms of the rate mechanism, the adjustment became effective in January 2010. The Rate CNP environmental adjustment is primarily attributable to scrubbers being placed in service during 2010 at four of Alabama Power's generating plants.

Rate CNP

The Company's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service and the recovery of retail costs associated with certificated power purchase agreements (PPAs) under a Rate CNP. There was no adjustment to the Rate CNP to recover certificated PPA costs in 2007, 2008, or 2009. Effective April 2010, Rate CNP will be reduced approximately $70 million annually, primarily due to the expiration on May 31, 2010 of the PPA with Southern Power covering the capacity of Plant Harris Unit 1.

Rate CNP also allows for the recovery of the Company's retail costs associated with environmental laws, regulations, or other such mandates. The rate mechanism is based on forward looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on invested capital. Retail rates increased approximately 0.6% in January 2007 and 2.4% in January 2008 due to environmental costs. In October 2008, the Company agreed to defer collection of any increase in rates under this portion of Rate CNP, which permits recovery of costs associated with environmental laws and regulations, from 2009 until 2010. The deferral of the retail rate adjustments had an immaterial impact on annual cash flows, and had no significant effect on the Company's revenues or net income. On December 1, 2009, the Company made its Rate CNP environmental submission of projected data for calendar year 2010, resulting in an increase to retail rates of approximately 4.3%, or an additional $195 million annually, based upon projected billings. Under the terms of the rate mechanism, this adjustment became effective in January 2010. The Rate CNP environmental adjustment is primarily attributable to scrubbers being placed in service during 2010 at four of the Company's generating units. See Note 3 to the financial statements under "Retail Regulatory Matters — Rate CNP" for further information.

Mississippi Baseload Construction Legislation

In the 2008 regular session of the Mississippi legislature, a bill was passed and signed by the Governor in May 2008 to enhance the Mississippi PSC's authority to facilitate development and construction of base load generation in the State of Mississippi (Baseload Act). The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant The effect of this legislation on the Company cannot now be determined

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properties. The Company has authority from the Mississippi PSC to recover approved environmental compliance costs through regulatory mechanisms.

Vectren Corp.

Rate & Regulatory Matters

Gas and electric operations with regard to retail rates and charges, terms of service, accounting matters, issuance of securities, and certain other operational matters specific to its Indiana customers are regulated by the IURC. The retail gas operations of the Ohio operations are subject to regulation by the PUCO.

Gas rates in Indiana contain a gas cost adjustment (GCA) clause. The GCA clause allows the Company to charge for changes in the cost of purchased gas. Electric rates contain a fuel adjustment clause (FAC) that allows for adjustment in charges for electric energy to reflect changes in the cost of fuel. The net energy cost of purchased power, subject to a variable benchmark based on NYMEX natural gas prices, is also recovered through regulatory proceedings. The IURC approved agreement authorizing this recovery expires in April 2010, and is subject to automatic annual renewals.

GCA and FAC procedures involve periodic filings and IURC hearings to establish the amount of price adjustments for a designated future period. The procedures also provide for inclusion in later periods of any variances between the estimated cost of gas, cost of fuel, and net energy cost of purchased power and actual costs incurred. The Company records any under-or-over-recovery resulting from gas and fuel adjustment clauses each month in margin. A corresponding asset or liability is recorded until the under-or-over-recovery is billed or refunded to utility customers.

The IURC has also applied the statute authorizing GCA and FAC procedures to reduce rates when necessary to limit net operating income to a level authorized in its last general rate order through the application of an earnings test. These earnings tests have not had any material impact to the Company's recent operating results.

Prior to October 1, 2008, gas costs were recovered in Ohio through a gas cost recovery (GCR) clause. The GCR clause operated similar to the GCA clause in Indiana. The PUCO periodically audited the GCR rates. The PUCO has completed all audits of periods prior to October 2008, and no issues or findings are outstanding. After October 1, 2008, the Company is no longer the supplier, and the GCR is no longer necessary.

Further, the IURC granted SIGECO authority to invest in an SO_2 scrubber at its generating facility that is jointly owned with ALCOA (the Company's portion is 150 MW). The order allows SIGECO to recover an approximate 8 percent return on capital investments through a rider mechanism, which is periodically updated for actual costs incurred less post in-service depreciation expense. The Company has invested approximately $100 million in this project. The scrubber was placed into service on January 1, 2009. Recovery through a rider mechanism of associated operating expenses including depreciation expense associated with the scrubber also began on January 1, 2009. The SO_2 scrubber is in compliance with the additional SO_2 reductions required by Phase I CAIR commencing on January 1, 2010.

One such project currently under construction is an interstate 345 kilovolt transmission line that will connect Vectren's A.B. Brown Generating Station to a station in Indiana owned by Duke Energy to the north and to a station in Kentucky owned by Big Rivers Electric Corporation to the south. Throughout the project, SIGECO is to recover an approximate 10 percent return, inclusive of the FERC approved equity rate of return of 12.38 percent, on capital investments through a rider mechanism which is updated annually for estimated costs to be incurred. Of the total investment, which is expected to approximate $75 million, as of December 31, 2009, the Company has invested approximately $21.3 million. The Company expects this project to be fully operational in 2011. At that time, any operating expenses including depreciation expense are also expected to be recovered through a FERC approved rider mechanism. Further, the approval allows for recovery of expenditures made even in the event currently unforeseen difficulties delay or permanently halt the project.

A significant portion of Vectren's electric utility sales are space heating and cooling. Accordingly, its operating results may fluctuate with variability of weather.

Vectren's electric utility sales are sensitive to variations in weather conditions. The Company forecasts utility sales on the basis of normal weather. Since Vectren does not have a weather-normalization mechanism for its electric operations, significant variations from normal weather could have a material impact on its earnings. However, the impact of weather on the gas operations in the Company's Indiana territories has been significantly mitigated through the **implementation in 2005 of a normal temperature adjustment mechanism.** Additionally, the implementation **of a straight fixed variable rate design over a two year period per a January 2009 PUCO order mitigates most weather risk related to Ohio residential gas sales.**

Rate Design Strategies
Sales of natural gas and electricity to residential and commercial customers are seasonal and are impacted by weather. Trends in average use among natural gas residential and commercial customers have tended to decline in recent years as more efficient appliances and furnaces are installed and the price of natural gas has been volatile. Normal temperature adjustment (NTA) and lost margin recovery mechanisms largely mitigate the effect on Gas Utility margin that would otherwise be caused by variations in volumes sold to these customers due to weather and changing consumption patterns. Indiana Gas' territory has both an NTA since 2005 and lost margin recovery since 2006. SIGECO's natural gas territory has an NTA since 2005 and lost margin recovery since 2007. The Ohio service territory had lost margin recovery since 2006. The Ohio lost margin recovery mechanism ended when new base rates went into effect in February 2009. This mechanism was replaced by a rate design, commonly referred to as a straight fixed variable rate design, which is more dependent on monthly service charge revenues and less dependent on volumetric revenues than previous rate designs. This new rate design, which will be fully implemented in February 2010, will mitigate most weather risk in Ohio. SIGECO's electric service territory has neither NTA nor lost margin recovery mechanisms; however, rate designs proposed in a recently filed rate case requests a lost margin recovery mechanism that works in tandem with conservation initiatives, similar to rate designs undertaken in the Indiana gas service territories.

Vectren North Gas Base Rate Order Received

On February 13, 2008, the Company received an order from the IURC which approved the settlement agreement reached in its Vectren North gas rate case. The order provided for a base rate increase of $16.3 million and a return on equity (ROE) of 10.2 percent, with an overall rate of return of 7.8 percent on rate base of approximately $793 million. The order also provides for the recovery of $10.6 million of costs through separate cost recovery mechanisms rather than base rates.

Further, additional expenditures for a multi-year bare steel and cast iron capital replacement program will be afforded certain accounting treatment that mitigates earnings attrition from the investment between rate cases. The accounting treatment allows for the continuation of the accrual for AFUDC and the deferral of depreciation expense after the projects go in service but before they are included in base rates. To qualify for this treatment, the annual expenditures are limited to $20 million and the treatment cannot extend beyond four years on each project.

With this order, the Company has in place for its North gas territory weather normalization, a conservation and lost margin recovery tariff, tracking of gas cost expense related to a uncollectible accounts expense level based on historical experience and unaccounted for gas through the existing GCA mechanism, and tracking of pipeline integrity management expense.

Vectren South Gas Base Rate Order Received
On August 1, 2007, the Company received an order from the IURC which approved the settlement reached in Vectren South's gas rate case. The order provided for a base rate increase of $5.1 million and a ROE of 10.15 percent, with an overall rate of return of 7.2 percent on rate base of approximately $122 million. The order also provided for the recovery of $2.6 million of costs through separate cost recovery mechanisms rather than base rates.

Further, additional expenditures for a multi-year bare steel and cast iron capital replacement program will be afforded certain accounting treatment that mitigates earnings attrition from the investment between rate cases. The accounting treatment allows for the continuation of the accrual for AFUDC and the deferral of depreciation expense after the projects go in service but before they are included in base rates. To qualify for this treatment, the annual expenditures are limited to $3 million and the treatment cannot extend beyond three years on each project.

With this order, the Company now has in place for its South gas territory weather normalization, a conservation and lost margin recovery tariff, tracking of gas cost expense related to a uncollectible accounts expense level based on historical experience and unaccounted for gas through the existing gas cost adjustment mechanism, and tracking of pipeline integrity management expense.

Vectren South Electric Base Rate Order Received
In August 2007, the Company received an order from the IURC which approved the settlement reached in Vectren South's electric rate case. The order provided for an approximate $60.8 million electric rate increase to cover the Company's cost of system growth, maintenance, safety and reliability. The order provided for, among other things: recovery of ongoing costs and deferred costs associated with the MISO; operations and maintenance (O&M) expense increases related to managing the aging workforce, including the development of expanded apprenticeship programs and the creation of defined training programs to ensure proper knowledge transfer, safety and system stability; increased O&M expense necessary to maintain and improve system reliability; benefit to customers from the sale of wholesale power by Vectren sharing equally with customers any profit earned above or below $10.5 million of wholesale power margin; recovery of and return on the investment in past demand side management programs to help encourage conservation during peak load periods; timely recovery of the Company's investment in certain new electric transmission projects that benefit the MISO infrastructure; an overall rate of return of 7.32 percent on rate base of approximately $1,044 million and an allowed ROE of 10.4 percent.

Wisconsin Energy

Wisconsin Energy

Other Utility Rate Matters

Oak Creek Air Quality Control System Approval In July 2008, we received approval from the PSCW granting Wisconsin Electric authority to construct wet flue gas desulfurization and selective catalytic reduction facilities at Oak Creek Power Plant units 5-8 Construction of these emission controls began in late July 2008, and we expect the installation to be completed during 2012 We currently expect the cost of completing this project to be approximately $800 million ($950 million including AFUDC) The cost of constructing these facilities has been included in our previous estimates of the costs to implement the Consent Decree with the EPA

Michigan Legislation During October 2008, Michigan enacted legislation to make significant changes in regulatory procedures, which should provide for more timely cost recovery Public Act 286 allows the use of a forward-looking test year in rate cases rather than historical data, and allows us to put interim rates into effect six months after filing a complete case Rate filings for which an order is not issued within 12 months are deemed approved In addition, we could seek a CPCN for new investment, and could recover interest on the investment during construction Public Act 286 also gives the MPSC expanded authority over proposed mergers and acquisitions, and requires action within 180 days of filing In addition, Public Act 295 calls for the implementation of a renewable portfolio standard of 10% by 2015, and energy optimization (efficiency) targets up to 1% annually by 2015 Public Act 295 specifically calls for current recovery of costs incurred to meet the standards, and provides for ongoing review and revision to assure the measures taken are cost effective

Fuel Cost Adjustment Procedure: Within the state of Wisconsin, Wisconsin Electric operates under a fuel cost adjustment clause for fuel and purchased power costs associated with the generation and delivery of electricity and purchase power contracts Embedded within its base rates is an amount to recover fuel costs Under the current fuel rules, no adjustments are made to rates as long as fuel and purchased power costs are expected to be within a band of the costs embedded in current rates for the 12-month period ending December 31 If, however annual fuel costs are expected to fall outside of the band, and actual costs fall outside of established fuel bands, then we may file for a change in fuel recoveries on a prospective basis

In June 2006, the PSCW opened a docket (01-AC-224) to consider revisions to the existing fuel rules (Chapter PSC 116) The current version of the revised rule recommends modifications to allow for annual plan and reconciliation filings of fuel costs by each regulated utility In the period between plan and reconciliation, escrow accounting would be used to record fuel costs outside a plus or minus 2% annual band of the total fuel costs allowed in rates The proposed rule further recommends that the escrow balance be trued-up annually following the end of each calendar year Currently, draft legislation is under review The earliest that we expect any possible action on the fuel rules is mid-2010

Edison Sault and Wisconsin Electric's operations in Michigan operate under a Power Supply Cost Recovery mechanism which generally allows for the recovery of fuel and purchased power costs on a dollar for dollar basis

Electric Transmission Cost Recovery: Wisconsin Electric divested its transmission assets with the formation of ATC in January 2001 We now procure transmission service from ATC at FERC approved tariff rates In connection with the formation of ATC, our transmission costs have escalated due to the socialization of costs within ATC and increased transmission infrastructure requirements in the state In 2002, in connection with the increased costs experienced by our customers, the PSCW issued an order which allowed us to use escrow accounting whereby we deferred transmission costs that exceeded amounts embedded in our rates We were allowed to earn a return on the unrecovered transmission costs we deferred at our weighted average cost of capital As of December 31, 2009, we had deferred $157 8 million of unrecovered transmission costs The escrow accounting treatment has been discontinued as our 2008 and 2010 PSCW rate orders have provided for recovery of these costs

Gas Cost Recovery Mechanism Our natural gas operations operate under GCRMs as approved by the PSCW Generally, the GCRMs allow for a dollar for dollar recovery of gas costs Prior to 2010, there was an incentive mechanism under the GCRMs that allowed for increased revenues if we acquired gas at prices lower than benchmarks approved by the PSCW However, as part of the January 2010 PSCW rate order, the PSCW approved changing from an incentive method to a modified one for one method The new method does not have revenue sharing The GCRMs measure commodity purchase costs against a monthly benchmark which includes a 2% tolerance Costs in excess of this monthly benchmark are subject to additional review by the PSCW before they can be passed through to our customers The modified one for one is the same method used by the other utilities in Wisconsin

Bad Debt Costs In March 2005, the PSCW approved our use of escrow accounting for residential bad debt costs The escrow method of accounting for bad debt costs allows for deferral of Wisconsin residential bad debt expense that exceeds amounts allowed in rates As part of the January 2010 PSCW rate order, the escrow accounting method for bad debt costs was extended through December 31, 2011

MISO Energy Markets The PSCW approved deferral treatment for our costs related to the implementation of the MISO Energy Markets Amounts deferred through December 31, 2007 are being recovered in rates For additional information, see Industry Restructuring and Competition -- Electric Transmission and Energy Markets

Wholesale Electric Pricing In August 2006, Wisconsin Electric filed a wholesale rate case with FERC The filing requested an annual increase in rates of approximately $16 7 million applicable to four existing wholesale electric customers This includes a mechanism for fuel and other cost adjustments In November 2006, FERC approved the rate filing subject to refund with interest Three of the existing customers' rates were effective in January 2007 The remaining wholesale customer's rates were effective in May 2007 FERC approved a settlement of the rate filing in September 2007 In August 2008, we issued a one time $62 5 million refund to our wholesale customers pursuant to a FERC approved settlement related to the sale of Point Beach

Depreciation Rates In January 2009, we filed a depreciation study with the PSCW, proposing new depreciation rates that would reduce annual depreciation expense by approximately $55 million The PSCW approved the depreciation study and the new depreciation rates began on January 1, 2010 We do not expect the new depreciation rates to have a material impact on earnings because the new depreciation rates were considered when the PSCW set our 2010 electric and gas rates

Renewables, Efficiency and Conservation In March 2006, Wisconsin revised the requirements for renewable energy generation by enacting Act 141 Act 141 defines "baseline renewable percentage" as the average of an energy provider's renewable energy percentage for 2001, 2002 and 2003 A utility's renewable energy percentage is equal to the amount of its total retail energy sales that are provided by renewable sources Wisconsin Electric's baseline renewable energy percentage is 2 27% Under Act 141, Wisconsin Electric could not decrease its renewable energy percentage for the years 2006-2009, and for the years 2010-2014, it must increase its renewable energy percentage at least two percentage points to a level of 4 27% Act 141 further requires that for the year 2015 and beyond, the renewable energy percentage must increase at least six percentage points above the baseline to a level of 8 27% Act 141 establishes a goal that 10% of all electricity consumed in Wisconsin be generated by renewable resources by December 31, 2015 Assuming the bulk of additional renewables is wind generation, Wisconsin Electric must obtain approximately 362 MW of additional renewable capacity by 2012 and another approximately 300 MW of additional renewable capacity by 2015 to meet the requirements of Act 141 We have

already started development of additional sources of renewable energy which will assist us in complying with Act 141 See Renewable Energy Portfolio discussion below

In 2007, the Governor of Wisconsin established the Governor's Task Force on Global Warming The Task Force issued its final report in July 2008 that includes an increased renewable portfolio standard Pursuant to the Task Force's recommendations, the renewable portfolio standard would increase to 10% by 2013, 20% by 2020 and 25% by 2025 Draft legislation regarding this recommendation, as well as other recommendations made by the Task Force, is pending in the Wisconsin legislature

Act 141 allows the PSCW to delay a utility's implementation of the renewable portfolio standard if it finds that achieving the renewable requirement would result in unreasonable rate increases or would lessen reliability, or that new renewable projects could not be permitted on a timely basis or could not be served by adequate transmission facilities Act 141 provides that if a utility is in compliance with the renewable energy and energy efficiency requirements as determined by the PSCW, then the utility may not be ordered to achieve additional energy conservation or efficiency Prior to Act 141, there had been no agreement on how to determine compliance with the Energy Priorities law which provides that it is the policy of the PSCW, to the extent it is cost effective and technically feasible, to consider the following options in the listed order when reviewing energy-related applications (1) energy conservation and efficiency, (2) noncombustible renewable energy resources (3) combustible renewable energy resources, (4) natural gas, (5) oil or low sulfur coal and (6) high sulfur coal and other carbon-based fuels

Act 141 also redirects the administration of energy efficiency, conservation and renewable programs from the DOA back to the PSCW and/or contracted third parties In addition Act 141 requires that 1 2% of utilities' annual operating revenues be used to fund these programs The Governor of Wisconsin's Task Force on Global Warming recommended in July 2008 that the energy efficiency goal be based on achieving efficiency resulting in a 2% reduction in electric load annually starting in 2015 rather than a goal based on a percent of revenue

Public Act 295 enacted in Michigan calls for the implementation of a renewable portfolio standard by 2015 and energy optimization (efficiency) targets up to 1% annually by 2015 Public Act 295

Xcel Energy

Xcel

Electric, Purchased Gas and Resource Adjustment Clauses

AQIR	Air quality improvement rider. Recovers, over a 15-year period, the incremental cost (including fuel and purchased energy) incurred by PSCo as a result of a voluntary plan to reduce emissions and improve air quality in the Denver metro area.
DSM	Demand side management. Energy conservation, weatherization and other programs to conserve or manage energy use by customers.
DSMCA	Demand side management cost adjustment. A clause permitting PSCo to recover demand side management costs over five years while non-labor incremental expenses and carrying costs associated with deferred DSM costs are recovered on an annual basis. Costs for the low-income energy assistance program are recovered through the DSMCA.
ECA	Retail electric commodity adjustment. Allows PSCo to recover its actual fuel and purchased energy expense in a calendar year to a benchmark formula. Short-term sales margins and margins from the sale of SO_2 allowances are shared with retail customers through the ECA.
FCA	Fuel clause adjustment. A clause included in electric rate schedules that provides for monthly rate adjustments to reflect the actual cost of electric fuel and purchased energy compared to a prior forecast. The difference between the electric costs collected through the FCA rates and the actual costs incurred in a month are collected or refunded in a subsequent period.
GCA	Gas cost adjustment. Allows PSCo to recover its actual costs of purchased natural gas and natural gas transportation. The GCA is revised monthly to coincide with changes in purchased gas costs.
OATT	Open Access Transmission Tariff
PCCA	Purchased capacity cost adjustment. Allows PSCo to recover from retail customers for all purchased capacity payments to power suppliers, effective Jan. 1, 2007. Capacity charges are not included in PSCo's electric rates or other recovery mechanisms.
PGA	Purchased gas adjustment. A clause included in NSP-Minnesota's and NSP-Wisconsin's retail natural gas rate schedules that provides for prospective monthly rate adjustments to reflect the forecasted cost of purchased natural gas and natural gas transportation. The annual difference between the natural gas costs collected through PGA rates and the actual natural gas costs is collected or refunded over the subsequent period.
QSP	Quality of service plan. Provides for bill credits to retail customers if the utility does not achieve certain operational performance targets and/or specific capital investments for reliability. The current QSP for the PSCo electric utility provides for bill credits to customers based on operational performance standards through Dec. 31, 2010. The QSP for the PSCo natural gas utility also expires Dec. 31, 2010.
RES	Renewable energy standard
RESA	Renewable energy standard adjustment
SCA	Steam cost adjustment. Allows PSCo to recover the difference between its actual cost of fuel and the amount of these costs recovered under its base steam service rates. The SCA is revised annually to coincide with changes in fuel costs.
SEP	State Energy Policy
TCR	Transmission cost recovery adjustment. Allows NSP-Minnesota to recover the cost of transmission facilities not included in the determination of NSP-Minnesota's electric rates in retail electric rates in Minnesota. The TCR was approved by the MPUC in 2006 to be effective in 2007, and will be revised annually as new transmission investments and costs are incurred.

NSP-Minnesota

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Minnesota's operations are regulated by the MPUC, the NDPSC and the SDPUC within their respective states. The MPUC has regulatory authority over aspects of NSP-Minnesota's financial activities, including security issuances, property transfers, mergers and transactions between NSP-Minnesota and its affiliates. In addition, the MPUC reviews and approves NSP-Minnesota's electric resource plans for meeting customers' future energy needs. The MPUC also certifies the need for generating plants greater than 50 MW and transmission lines greater than 100 KV.

No large power plant or transmission line may be constructed in Minnesota except on a site or route designated by the MPUC. The NDPSC and SDPUC have regulatory authority over generating and transmission facilities, and the siting and routing of new generation and transmission facilities in North Dakota and South Dakota, respectively.

NSP-Minnesota is subject to the jurisdiction of the FERC with respect to its wholesale electric operations, hydroelectric licensing, accounting practices, wholesale sales for resale, transmission of electricity in interstate commerce and certain natural gas transactions in interstate commerce. NSP-Minnesota has received authorization from the FERC to make wholesale electric sales at market-based prices (see Market Based Rate Rules discussion) and is a transmission-owner member of the MISO RTO.

Fuel, Purchased Energy and Conservation Cost-Recovery Mechanisms — NSP-Minnesota has several retail adjustment clauses that recover fuel, purchased energy and other resource costs:

- *CIP* — The CIP invests in programs that help customers save energy. CIP includes a comprehensive list of programs that benefit all customers including Saver's Switch®, energy efficiency rebates and energy audits.
- *EIR* — The EIR recovers the costs of environmental improvements to the A. S. King, High Bridge and Riverside plants, which were renovated under the MERP program.
- *GAP* — The GAP is a surcharge billed to all non-interruptible customers to recover the costs of offering a low-income customer co-pay program designed to reduce natural gas service disconnections.
- *MCR* — The MCR recovers costs related to reducing Mercury emissions at two NSP-Minnesota fossil fuel power plants.
- *RDF* — The RDF allocates money to support development of renewable energy projects research and development of renewable energy technologies.
- *RES* — In 2007, the Minnesota legislature passed new requirements mandating that a certain percent of energy produced by utilities like NSP-Minnesota come from renewable resources. In order to ensure these mandates can be met, the legislature allows utilities to recover the costs of new renewable generation projects to meet the RES in a rider.
- *SEP* — The SEP recovers costs related to various energy policies approved by the Minnesota legislature.
- *TCR* — The TCR recovers costs associated with new investments in the electric transmission system necessary to deliver electric energy to customers.

NSP-Minnesota's retail electric rate schedules in Minnesota, North Dakota and South Dakota include a FCA for monthly billing adjustments for changes in prudently incurred cost of fuel, fuel related items and purchased energy. NSP-Minnesota is permitted to recover these costs through FCA mechanisms approved by the regulators in each jurisdiction.

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The FCAs allow NSP-Minnesota to bill customers for the cost of fuel and fuel related costs used to generate electricity at its plants and energy purchased from other suppliers. In general, capacity costs are not recovered through the FCA. In addition, costs associated with MISO are generally recovered through either the FCA or through rate cases.

NSP-Minnesota is required by Minnesota law to spend a minimum of 2 percent of Minnesota electric revenue on conservation improvement programs. These costs are recovered through an annual cost-recovery mechanism for electric conservation and energy management program expenditures. NSP-Minnesota is required to request a new cost-recovery level annually. While this law changed to a savings-based requirement beginning in 2010, the costs of providing qualified conservation improvement programs will continue to be recoverable through a rate adjustment mechanism.

MERP Rider Regulation — The MPUC approved a rate rider to recover prudent costs to convert two coal-fueled electric generating plants to natural gas, and to install advanced pollution control equipment at a third coal-fired plant beginning Jan. 1, 2006. A. S. King, High Bridge and Riverside went into service in July 2007, May 2008 and March 2009, respectively. In December 2009, the MPUC authorized the recovery of approximately $116.7 million in 2010 rates. The ROE for the A. S. King plant, the High Bridge plant and the Riverside plant, is 10.55 percent, 11.22 percent and 10.55 percent, respectively. The MERP projects will be included in rate base in the next general rate case and the projects removed from the rider.

NSP-Wisconsin

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Wisconsin's operations are regulated by the PSCW and the MPSC, within their respective states. In addition, each of the state commissions certifies the need for new generating plants and electric transmission lines before the facilities may be sited and built. NSP-Wisconsin is subject to the jurisdiction of the FERC with respect to its wholesale electric operations, hydroelectric generation licensing, accounting practices, wholesale sales for resale the transmission of electricity in interstate commerce and certain natural gas transactions in interstate commerce. NSP-Wisconsin has received authorization from the FERC to make wholesale electric sales at market-based prices (see Market Based Rate Rules discussion) and is a transmission-owning member of the MISO RTO.

The PSCW has a biennial base-rate filing requirement. By June of each odd-numbered year, NSP-Wisconsin must submit a rate filing for the test year beginning the following January.

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Bay Front Biomass Gasification — In December 2009, the PSCW granted NSP-Wisconsin a certificate of authority to install biomass gasification technology at the Bay Front Power Plant in Ashland, Wis. The project will convert a third boiler to biomass gasification technology allowing the plant to use up to 100 percent biomass in all three boilers. The project, estimated to cost $58 million, will require additional biomass receiving and handling facilities at the plant, an external gasifier, minor modifications to the plant's remaining coal-fired boiler and an enhanced air quality control system. The project is expected to improve the environmental performance of the plant and contribute towards state RES in the region. Engineering and design are expected to begin in 2010, and the unit could be operational by late 2012.

NSP-Minnesota also made filings in North Dakota and Minnesota requesting future rate recovery of the portion of the project costs that will be billed to NSP-Minnesota through the Interchange Agreement. Decisions on those filings are currently pending regulatory action before the NDPSC and the MPUC respectively.

Fuel and Purchased Energy Cost Recovery Mechanisms — NSP-Wisconsin does not have an automatic electric fuel adjustment clause for Wisconsin retail customers. Instead, it has a procedure that compares actual monthly and anticipated annual fuel costs with those costs that were included in the latest retail electric rates. If the comparison results in a difference of 2 percent above or below base rates, the PSCW may hold hearings limited to fuel costs and revise rates upward or downward. Any revised rates would remain in effect until the next rate change. The adjustment approved is calculated on an annual basis, but applied prospectively. NSP-Wisconsin's wholesale electric rate schedules include an FCA to provide for adjustments to billings and revenues for changes in the cost of fuel and purchased energy.

NSP-Wisconsin's retail electric rate schedules for Michigan customers include power supply cost recovery factors, which are based on 12-month projections. After each 12-month period, a reconciliation is submitted whereby over-collections are refunded and any under-collections are collected from the customers over the subsequent 12-month period.

Wisconsin Fuel Cost Recovery Legislation — Existing statutes prohibit the use of automatic adjustment clauses by large investor-owned electric public utilities, but authorize the PSCW to approve a rate increase to allow for the recovery of costs caused by an emergency or extraordinary increase in the cost of fuel.

In November 2009, a bill was introduced in the Wisconsin legislature to modify the existing statutes and rules governing electric fuel cost recovery in utility rates. Under the proposed statutes, an electric utility would submit a forward-looking annual fuel cost plan for approval by the PSCW. Once a utility has an approved fuel cost plan, it could then defer any under-collection or over-collection of fuel costs for future rate recovery or refund, providing that the under/over-collection exceeds a symmetrical annual tolerance band established by the PSCW. Approval of a fuel cost plan and any rate adjustment for recovery or refund of deferred costs would be determined by the PSCW after opportunity for a hearing. If passed, the legislation would require the PSCW to promulgate rules to implement the new statutes.

NSP-Wisconsin expects hearings on the legislation to occur in the 2010 session; however, at this time it is uncertain what, if any, additional action the legislature will take with respect to this legislation.

Wisconsin RPS and Energy Efficiency and Conservation Goals — The Wisconsin legislature has passed an RPS that requires 10 percent of electric sales statewide to be supplied by renewable energy sources by the year 2015. However, under the RPS, each individual utility must increase its renewable percentage by 6 percent over its baseline level. For NSP-Wisconsin, the RPS is 12.89 percent. NSP-Wisconsin anticipates it will meet the RPS requirements with its pro-rata share of existing and planned renewable generation on the NSP System.

ARCs — In 2009, the FERC adopted rules requiring MISO to allow ARCs to offer demand response aggregation services to end-use customers in the states served by NSP-Wisconsin, unless the applicable state regulatory authority prohibits ARCs from serving retail customers in their state. ARCs would operate in competition with the state-regulated retail demand response programs offered by NSP-Wisconsin. The MISO ARC tariff provisions are effective in June 2010. During 2009, the PSCW and MPSC issued orders temporarily prohibiting ARCs from operating in Wisconsin and Michigan, respectively, pending further regulatory proceedings. NSP-Wisconsin expects the PSCW and MPSC to conduct additional proceedings following the implementation of the MISO ARC tariffs.

PSCo

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — PSCo is regulated by the CPUC with respect to its facilities, rates, accounts, services and issuance of securities. PSCo is regulated by the FERC with respect to its wholesale electric operations, accounting practices, hydroelectric licensing, wholesale sales for resale, the transmission of electricity in interstate commerce and certain natural gas transaction in interstate commerce. PSCo has received authorization from the FERC to make wholesale electricity sales at market-based prices; however, PSCo withdrew its market-based rate authority with respect to sales in its own and affiliated operating company control areas.

Fuel, Purchased Energy and Conservation Cost-Recovery Mechanisms — PSCo has several retail adjustment clauses that recover fuel, purchased energy and other resource costs:

- *ECA* — The ECA recovers fuel and purchase power costs. Short-term sales margins and margins from the sale of SO_2 allowances are shared with retail customers through the ECA. The total incentive cannot exceed $11.25 million in any year. For 2009, it included an incentive adjustment to encourage efficient operation of base load coal plants and to encourage cost reductions through purchases of economical short-term energy. Effective Jan. 1, 2010, the incentive adjustment was eliminated from the ECA mechanism. The ECA mechanism is revised quarterly.

- *PCCA* — The PCCA allows for recovery of purchased capacity payments for most power purchase agreements. New rates went into effect Jan. 1, 2010.

- *SCA* — The SCA allows PSCo to recover the difference between its actual cost of fuel and the amount of these costs recovered under its base steam service rates. The SCA rate is revised annually on Jan. 1, as well as on an interim basis to coincide with changes in fuel costs.

- *AQIR* — Effective January 2003, the AQIR recovers, over a 15-year period, the incremental cost (including fuel and purchased energy) incurred by PSCo as a result of a voluntary plan to reduce emissions and improve air quality in the Denver metro area. The CPUC approved PSCo's filing to roll the AQIR into base rates, which was reflected in rates on Jan. 1, 2010.

- *DSMCA* — The DSMCA clause permits PSCo to recover DSM and interruptible service option credit (ISOC) costs on a concurrent basis and performance initiatives based on achieving various energy savings goals. The CPUC approved recovery of the full amount of DSM-related costs through the combination of base rates and a tracker mechanism in the DSMCA starting in 2010.

- *RESA* — The RESA recovers the incremental costs of compliance with the RES and is set at its maximum level of 2 percent of the customer's total bill.

- *Wind Energy Service* — Is a premium service for those customers who voluntarily choose to contribute funds for the acquisition of additional renewable resources beyond the level of PSCo's resource plan. Wind Energy Service customers pay a charge that is in addition to the rates paid by other customers. The service is marketed as WindSource®.

- *Transmission Cost Adjustment (TCA)* — Effective January 2008, the TCA provides for the recovery outside of rate cases of transmission plant revenue requirements and allows for a return on construction work in progress for transmission investments.

PSCo recovers fuel and purchased energy costs from its wholesale electric customers through a fuel cost adjustment clause accepted for filing by the FERC. PSCo's larger wholesale customers have agreed to pay the full cost of the acquisition of certain non-solar renewable energy purchase and generation costs through a rider and in exchange receive renewable energy credits associated with those resources.

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Performance-Based Regulation Plan (PBRP) and Quality of Service Requirements — PSCo currently operates under an electric and natural gas PBRP. The major components of this regulatory plan include:

- An electric QSP that provides for bill credits to customers if PSCo does not achieve certain performance targets relating to electric reliability and customer service through 2010; and

- A natural gas QSP that provides for bill credits to customers if PSCo does not achieve certain performance targets relating to natural gas leak repair time and customer service through 2010.

PSCo regularly monitors and records as necessary an estimated customer refund obligation under the PBRP. In April of each year following the measurement period, PSCo files its proposed rate adjustment under the PBRP. The CPUC conducts proceedings to review and approve these rate adjustments annually.

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — The PUCT and NMPRC regulate SPS' retail electric operations and have jurisdiction over its retail rates and services and the construction of transmission or generation in their respective states. The municipalities in which SPS operates in Texas have original jurisdiction over SPS' rates in those communities. SPS can and does then appeal municipal rate decisions to the PUCT. The NMPRC also has jurisdiction over the issuance of securities. SPS is subject to the jurisdiction of the FERC with respect to its wholesale electric operations, accounting practices, wholesale sales for resale, the transmission of electricity in interstate commerce and certain natural gas transactions in interstate commerce.

Fuel, Purchased Energy and Conservation Cost-Recovery Mechanisms — Fuel and purchased energy costs are recovered in Texas through a fixed fuel and purchased energy recovery factor, which is part of SPS' retail electric tariff. The regulations allow retail fuel factors to change up to three times per year.

Because regulations require that actual fuel and purchased energy costs be recovered from ratepayers, there is an accounting of over- or under-recovery of fuel and purchased energy expenses under the fixed factor. Regulations also require refunding or surcharging over- or under- recovery amounts, including interest, when they exceed 4 percent of the utility's annual fuel and purchased energy costs on a rolling 12-month basis, if this condition is expected to continue.

PUCT regulations require periodic examination of SPS fuel and purchased energy costs, the efficiency of the use of fuel and purchased energy, fuel acquisition and management policies and purchased energy commitments. SPS is required to file an application for the PUCT to retrospectively review fuel and purchased energy costs at least every three years.

The NMPRC has authorized SPS to continue to use a monthly adjustment factor for a fuel and purchased power cost adjustment clause (FPPCAC) for SPS' New Mexico retail jurisdiction. NMPRC regulations require SPS to periodically request authority to continue using its FPPCAC. In that proceeding, the NMPRC reviews SPS' use of its FPPCAC since the filing of its previous fuel clause continuation filing. SPS' next fuel clause continuation filing is due Aug. 26, 2010.

SPS recovers fuel and purchased energy costs from its wholesale customers through a monthly wholesale fuel and purchased economic energy cost adjustment clause accepted for filing by the FERC.

Performance-Based Regulation and Quality of Service Requirements — In Texas, SPS is subject to a QSP requiring SPS to comply with electric service reliability performance targets. In October 2008, the PUCT staff served SPS with notice that it had initiated an investigation to determine whether SPS is in compliance with the Texas statutes and PUCT rules on reliability and continuity of service.

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Texas EECRF Rider — PUCT regulations established the mechanism under which electric utilities may recover costs associated with providing energy efficiency programs. That mechanism, an EECRF rider, must be included in a utility's tariff and may be established in a utility's base rate case or through a separate request seeking to establish an EECRF. In accordance with this rule, SPS has removed its energy efficiency costs from its recent base rate proceeding, and has requested implementation of its EECRF rider to recover the remaining unamortized balance of historic costs and its projected 2008 and 2009 energy efficiency costs. In September 2008, the PUCT concluded that the rule under which the application was filed does not apply to SPS and the energy efficiency costs could be recovered in the pending Texas retail base rate case. SPS reached a negotiated settlement with the parties and included base rate recovery amounts explicitly designated for energy efficiency. In February of 2010, the PUCT issued a proposed rule that would make SPS subject to the same requirements with respect to the EECRF as other utilities in the state.

New Mexico Energy Efficiency Disincentive Rulemaking — During the last legislative session, increased energy efficiency goals and more affirmative disincentive language were adopted. The NMPRC is currently conducting a rulemaking proceeding to update the energy efficiency rule, consistent with the legislative changes.

SPS Participation in the SPP RTO — In October 2007, the NMPRC ordered an investigation of the benefits of SPS' participation in the SPP RTO. The conversion of SPS' retail load to transmission service under the SPP tariff effective Feb. 1, 2010 was mandatory under the SPP membership agreement. In September 2009, the parties filed a stipulation resolving all issues in the proceeding for a five year interim period. On Feb. 2, 2010, the NMPRC approved the settlement authorizing SPS to put its retail load under the SPP OATT effective Jan. 1, 2010.

TUCO to Woodward District Extra High Voltage (EHV) Interchange — The SPP, as a part of its balance portfolio plan, issued a notice in June 2009 directing SPS to construct a 178 mile 345 KV transmission line between Lubbock, Texas and Woodward, Okla. The estimated investment in the new line is $149 million and will be recovered from SPP members, including SPS, in accordance with the SPP OATT and the retail ratemaking process. A decision is pending.