History of Colorado Energy Industry Regulatory Incentives

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The Colorado Public Utilities Commission

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Executive Summary

The purpose of this report is to summarize the regulatory history of the various incentives that make up the current Colorado regulatory landscape. For each incentive category covered in the report, Table A provides an index of the key decision numbers, docket numbers, and a brief summary of the decision. For most readers, Table A[1] is a good beginning point to obtain an overview of the history of Commission decisions and legislative directives. The body of the report provides an expanded discussion of the various incentives and a brief discussion of the context shaping the Commission's incentive decisions.

The goal of this report is to assist the Commission, its staff, and interested parties in locating the various decisions which form the history of Colorado utility regulation, and more importantly, to help understand the historical context for the current set of incentives.

After a brief introduction to regulatory incentives in Section 1, Section 2 begins by noting that traditional rate base-rate of return regulation sometimes is characterized as "cost-plus" regulation, implying that utility management has no financial incentives to be concerned about cost containment and operational efficiency. This section points out that some efficiency incentives exist within the traditional regulatory structure, due to the operation of regulatory lag and the fact that utilities are given an opportunity (but not a guarantee) to earn a fair rate of return.

Section 3 discusses the Commission decisions establishing the performance based regulatory (PBR) plan which was in effect from 1997 through 2006 for Public Service's electric operations. In PBR plans, utilities agree to share "overearnings" with customers in return for a rate case moratorium.

The largest portion of this report is devoted to automatic adjustment mechanisms which are discussed in Section 4. These mechanisms allow a utility to pass on increases or decreases in some particular category of costs to customers without the necessity of a general rate case. Automatic adjustment mechanisms have been used in Colorado since the 1970s for both electric fuel costs and purchased gas costs. There has been a steady increase over time in the types of costs that are covered by these mechanisms.

Section 4 begins with a discussion of the advantages and disadvantages of these mechanisms. The remainder of this section discusses the history of the Commission's regulatory decisions for seven adjustment mechanisms covering the following cost categories: electric fuel costs; purchased gas costs for gas customers; purchased capacity costs; demand side management costs; air quality improvement costs; renewable energy costs; and transmission costs.

[1] Table A is organized and numbered consistently with the body of the report. For example, Section 3 of the report discusses incentive Regulation–Earnings Sharing and Section 3 of Table A provides the summary of relevant decisions and dockets.

Section 5 discusses the Commission's consideration of price volatility management and trading issues. Beginning in the late 1990s, Colorado natural gas utilities experienced rapid and large increases in the cost of natural gas purchased in wholesale markets. Beginning in 2001, the Commission adopted rules requiring gas utilities to report the measures each utility considered to reduce customers' risk of gas price volatility for the upcoming year.

In the past decade the penetration of natural gas generation has increased substantially - strengthening the link between natural gas prices and retail electricity prices. This has led to the use of hedging "insurance" for natural gas used in electric generation. The last portion of Section 5 discusses the Commission's treatment of wholesale trading by regulated utilities. Trading has expanded during the past decade due to the various FERC initiatives that promoted a more robust wholesale electricity market.

Section 6 discusses Commission decisions and legislative requirements affecting utility resource acquisition decisions. The first two subsections discuss another type of incentive – a legislative mandate to deploy minimum levels of DSM and renewable resources in Colorado. In addition, the legislature provided incentives for Colorado electric utilities to develop integrated gasification combined cycle generation facilities that use western coal at high altitude combined with carbon dioxide sequestration. This section concludes with a review of Commission regulatory decisions concerning decoupling of utility profits from sales and the treatment of construction work in progress.

Section 7 reviews Commission service quality and reliability decisions. The original motivation for the adoption of service quality plans was concern that the PBR mechanism may lead to deterioration in service quality. The PBR mechanism provided cost-reduction incentives which potentially create incentives to reduce service quality. Under service quality plans, utilities must provide bill credits to customers if service quality falls below an established threshold.

This report describes the history of existing Colorado energy industry regulatory incentives. A review of Table A shows many types of incentives that have evolved over a long period of time and through a series of Commission decisions. In addition, Table A shows that many Commission decisions involve the establishment and modification of automatic adjustment mechanisms which have expanded over the past decades. Finally, Table A indicates that the Colorado legislature recently has begun to establish regulatory incentives, particularly in the areas of mandates and options for the acquisition of electricity resources.

Section 1
Introduction

The Colorado Public Utilities Commission ("Commission") recently opened Docket No. 08I-113EG for the purpose of examining regulatory and rate incentives for electric and gas customers. Decision No. C08-448 in Docket No. 08I-113EG states:

> We find that there is a need for greater understanding, by the Commission and its Staff, of the following: (1) the manner in which the existing regulatory structures and incentives influence energy utilities' behaviors; (2) the extent to which these incentives align results with Commission policy goals; (3) the manner in which alternative regulatory structures and incentives for these utilities may impact their actions; and (4) the extent to which these alternative regulatory structures may achieve results consistent with Commission policy goals.

The purpose of this report is to provide a summary of the history of the various incentives that make up the current Colorado regulatory landscape. For each category of incentives, Table A provides an index of the key decision and docket numbers. Within the body of the report is a summary and history of the various incentives and a brief discussion of the context shaping the Commission's incentive policy.

The Commission is undertaking this incentive investigation during a period of significant challenges and uncertainty in the electricity and natural gas industries. The natural gas industry faces significant price volatility and long-term supply concerns. The electric utility industry is confronted with global climate change concerns, increasing construction costs and fossil fuel prices, and difficulty in building new electric generation and transmission resources. The magnitude of the global warming challenge is demonstrated by Governor Ritter's recently announced Climate Action Plan which establishes a short-term greenhouse-gas reduction goal of 20 percent below 2005 levels by 2020 and a long-term goal of 80 percent reduction below 2005 levels by 2050.

Finally it should be noted that in response to these challenges, the Colorado legislature passed a series of new energy-related laws during the past two years. The fact that some of the incentives discussed in this report have been created by the legislature creates an additional factor for the Commission to consider in its examination.

This report is organized as follows: Section 2 provides a brief summary of the incentives that are a part of traditional rate base-rate of return regulation; Section 3 discusses the history of performance based regulation in Colorado; Section 4 addresses the incentive implications of automatic adjustment mechanisms and the specifics of each mechanism currently used in Colorado; Section 5 discusses price volatility management and electricity trading incentives; Section 6 provides a summary of the resource acquisition incentives and mandates; and Section 7 concludes with a discussion of quality of service incentives.

Section 2
Traditional Regulation

One important feature of competitive markets is that the dynamics of competition drive producers to reduce production costs in order to increase profits or even to survive in the struggle for customers. This incentive for companies to operate efficiently and reduce costs is regarded as one of the most important characteristics of competition.

In considering regulated industries, critics sometimes characterize traditional rate base-rate of return as “cost-plus” regulation, implying that utility management has no financial incentive to be concerned about cost containment and operational efficiency because all costs simply are recovered from customers who lack alternative suppliers. While it is generally true that all prudently incurred costs are recovered from customers at the conclusion of a rate case, efficiency incentives exist within the traditional regulatory structure.

Under common regulatory practice, utilities are given an opportunity (but not a guarantee) to earn a fair rate of return. As a result, utilities may be under some pressure to reduce costs in order to actually realize the authorized rate of return.   The operation of “regulatory lag” also provides efficiency incentives. Regulatory lag refers to the fact that there is a delay between the time that the actual rate of return varies from the Commission-authorized rate and the time that the new rate actually takes effect. As a result, if utility management is able to reduce costs and to increase efficiency between rate cases, the cost savings result in increasing shareholder returns.

In addition, utility management has an incentive to increase sales during the period between rate cases. This has led to concerns the utility management may not have financial incentives to pursue cost-effective demand side management (DSM) measures because it reduces incremental sales and utility profits. Decoupling utility profits from sales has been suggested as one solution to the incentive to increase utility sales. This concept is discussed in Section 6.4.

Section 3
Incentive Regulation – Earnings Sharing

Performance Based Regulation: Public Service Company of Colorado[2] filed an application in which it sought Commission authorization to merge with Southwestern Public Service Company (SPS) through the formation of a registered public utility holding company called New Century Energies (NCE). By Decision No. C96-1235 in Docket No. 95A-531EG, the Commission approved a settlement in the case which created what was referred to as a performance based regulatory (PBR) plan.[3] As a part of this PBR plan,[4] the parties agreed to an earnings test and a sharing mechanism which applied only to Public Service's electric department. According to the settlement, Public Service's earnings were measured using the ratemaking principles from PSCo's last rate case proceedings (Dockets No. 93S-001EG and No. 95I-513E). The PBR plan and earnings test applied to the years 1997 through 2001.

The Commission-approved PBR plan featured a "reverse taper." Excess earnings greater than 11 percent, to and including 12 percent return on equity (ROE), were allocated 65 percent to ratepayers. For earnings greater than 12 percent to and including 14 percent ROE, ratepayers and the Company shared the excess earnings equally. Above 14 percent, to and including 15 percent ROE, the Company was allocated 65 percent of the excess earnings. Above 15 percent ROE, all excess earnings were to be returned to ratepayers.

In order to provide efficiency incentives, the parties agreed that the Company's base electric rates would not be changed prior to December 31, 2001. The Commission ruled that it could not prohibit the Company from filing a rate case, or to prohibit any party from filing a complaint.[5]

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[2] This report refers to Public Service Company of Colorado, an operating division of Xcel Energy, as Public Service, PSCo, or Company.

[3] Public Service proposed two earnings-sharing incentive plans in the early 1990s. PSCo proposed a Regulatory Earnings Incentive Plan in conjunction with its 1991 general rate case (Docket 91S-091EG). In its 1993 rate case (Docket No. 93S-001EG), Public Service proposed an Earnings and Service Quality Incentive Plan. It appears that both plans were withdrawn and not ruled upon by the Commission.

[4] It should be noted that in 1992 the Commission established an Alternative Form of Regulation (AFOR) plan for US WEST (Decision No. C92-854). A key component of the AFOR was an earnings sharing plan.

[5] The settlement addressed the possibility of a party filing for rate a rate change during the "rate freeze." According to the settlement, if Public Service filed to change rates outside of the specified exceptions, the earnings test sharing mechanism, annual $18 million reduction in base electric rates, and the modified ECA would remain in place until the issuance of a final Commission decision in the rate change filing. If a complaint or show cause proceeding regarding PSCo's rates is initiated, under the settlement the Company has the right to immediately terminate the earnings sharing mechanism. The electric rate reduction and the modified ECA mechanism were to remain in place until the issuance of a final Commission decision in the show cause or complaint proceeding.

Finally, it should be noted that the implementation of the PBR earnings test superseded the imposition of an earnings test that the Commission adopted as a condition for the approval of an automatic adjustment mechanism to recover capacity costs associated with qualifying facilities (QFCCA). This topic is discussed in greater detail in Section 4.4.[6]

By Decision No. C00-393 in Docket 99A-373E, the Commission approved a settlement of the New Century Energies - Northern States Power merger, which created Xcel Energy. This decision extended Public Service's electric earnings sharing mechanism through calendar year 2006. The Commission stated:

> The electric earnings sharing mechanism is part of the Performance Based Regulation (PBR) that was a central pillar of the Commission's approval of the Public Service/SPS merger in Docket No. 95A-531EG. The PBR creates the incentive for Public Service to pursue cost savings and allows for those efficiencies to be shared with Colorado consumers. The extension to the electric earnings sharing mechanism will allow Colorado consumers to continue to share in any additional cost savings achieved by Public Service after base rates are reset in the 2002 electric rate case.

By Decision C07-1008 in Docket No. 07A-388G, the Commission approved a settlement which established an earnings sharing for Atmos Energy. The settlement addressed excess earnings for Atmos in 2006 and established a sharing mechanism for any excess earnings in 2007. The agreement did not address potential excess earnings after 2007. The customer’s share of the excess earnings begins at 25 percent if the ROE is 10.25 percent or greater. The customer’s share increases to 75 percent if the ROE is greater than 13.25 percent.

Context: The PBR plan was a key element of the two Public Service merger decisions. The PBR created efficiency incentives but also was a convenient mechanism to share expected merger costs savings with ratepayers.

In considering the efficiency incentives related to earnings sharing, it is useful to consider two cases: 1) PSCo’s earnings are below its authorized return; and 2) PSCo’s earnings exceed its authorized return.

If PSCo’s earnings are below its authorized rate of return, then the Company has incentives to reduce its costs because it retains 100 percent of the incremental savings due to such cost reductions. This is true whether or not an earnings test exists and regardless of the earnings sharing percentage.

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[6] By Decision No. C95-1169 in Docket No. 95S-041E, the Commission required Public Service to implement a QFCCA earnings test on October 1, 1996, unless the Commission issued a decision that established a comprehensive form of performance based incentive regulation (PBR) for Public Service prior to September 1, 1996. The Commission terminated the QFCCA earnings test scheduled to become effective October 1, 1996.

The impact of an earnings test on incentives is more complicated if PSCo's earnings exceeds its authorized rate of return. Under the PBR, utility shareholders generally retained a portion of any costs savings, thus providing some incentive for efficiency, although less of an incentive than if no earnings test were present. If the Company was in the first sharing bracket, it retained only 35 percent of any savings. Thus, the earnings test weakens the efficiency incentives compared to traditional regulation. This weakened incentive is balanced against the commitment for a five-year period during which no new rate cases were to be filed. This gives the utility some certainty concerning the period of time that it will be allowed to retain some benefits from cost reductions.

An attractive component of PBR was its ability to share cost savings resulting from expected merger synergies with ratepayers. In the first merger, PSCo and SPS projected net financial savings resulting from the merger of approximately $770 million (in nominal dollars) over a ten-year period. In the New Century Energies – Northern States Power merger estimated potential ten-year net merger savings were approximately $1.1 billion.

Section 4
Automatic Adjustment Mechanisms

Section 4.1 Purpose and criteria

Automatic adjustment mechanisms allow a utility to pass on increases or decreases in some particular category of costs to customers without the necessity of a general rate case.

Advantages: Automatic adjustment mechanisms help avoid regulatory lag and the need for frequent rate cases. For example, if a particular category of costs constitutes a large component of a utility's total expense and increases rapidly, a utility may be unable to change rates fast enough to recover these costs. In this instance the utility would be forced to file frequent rate cases and may be unable to earn its authorized rate of return.

In addition, automatic adjustment mechanisms help provide the better price signals to customers, since the full impact of cost changes are more timely reflected in new rates.

Finally, the use of automatic adjustment mechanisms could be viewed by the investment community as decreasing the utility's risk. Consequently, such mechanisms could allow a utility to raise capital on more favorable terms.

Disadvantages: Since automatic adjustment clauses reduce regulatory lag, they also diminish the efficiency incentives that are a part of regulatory lag. The concern is that if some expense, such as fuel, is passed on to customers on a dollar-for-dollar basis, utility management has no direct financial incentive to control this expense. From a pure profit maximization perspective, management should allocate its scarce resources (money, time, creative energy) in areas with the greatest expected return to shareholders.

Automatic recovery mechanisms raise concern about piecemeal ratemaking. Piecemeal ratemaking refers to allowing the utility to increase rates to cover demonstrated increased costs associated with one cost category, while failing to look at the utility's overall financial situation to determine whether other costs have decreased or revenues have increased.

Finally, there is concern that utility management may have an incentive to alter its resource mix in order to use the item subject to a clause more intensively.

It should be remembered that, regardless of the Commission's policy regarding automatic adjustment mechanisms, utilities are entitled to fully recover prudently incurred costs during a subsequent rate case. Automatic adjustment mechanisms are concerned with the treatment of costs in the periods between rate cases.

Criteria: The Commission undertook an investigation of the recovery of electric fuel costs in Docket No. 93I-702E. On page five of Decision No. C95-248 the Commission stated:

> Staff summarized past Commission justification for electric adjustment clauses as being: (1) the expense item included in the adjustment clause constitutes a significant portion of the utility's total costs; (2) costs or price for the expense item is beyond the utility's control; (3) the price of the expense item is increasing at a rate in excess of the general rate of inflation; and (4) there is volatility in the price of the expense item.

Add "Incentives" to adjustment mechanisms: Over time there have been attempts to introduce an incentive component to adjustment mechanisms. For example, an electric incentive fuel cost adjustment mechanism was used by jurisdictional utilities in the late 1990s. Under this approach, only a portion (for example 50 percent) of the change in fuel cost was passed on to customers. This addition of regulatory lag provided a financial incentive for utility management to expend resources to control such costs. In addition, the Commission approved a modified incentive mechanism for PSCo in which cost recovery depended on coal plant availability, generating plant heat rates, and the price paid for natural gas used in generating plants.

Section 4.2 Fuel costs (electric)

Public Service Company of Colorado:

Automatic adjustment mechanisms have been used to recover the cost of fuel used in electric generation facilities since the 1970s. By Decision No. 89225 in Case No. 5700 (dated August 17, 1976); the Commission stated that the reason for the fuel cost adjustment (FCA) was to permit rapid recovery of increased costs over which the utility has no control. The Commission recognized that, in the circumstances which existed at the time, unless increased fuel costs were passed through to customers expeditiously, the utility would undergo serious earnings erosion. The Commission observed that this erosion of earnings would, in turn, jeopardize the utility's ability to provide service.

The FCA refers to the Fuel Cost Adjustment. During the 1970s the FCA was used to recover the costs associated with fuel used in PSCo power plants. In 1978, the Commission approved a Firm Purchased Power Adjustment (FPPA) mechanism to recover the costs of firm power purchases[7]. By Decision No. C80-1592 in Application No. 32603, the Commission granted PSCo's application to establish an electric cost adjustment mechanism (ECA) that essentially combined the FCA and FPPA mechanisms into a single tariff.

In PSCo's 1993 general rate case, Docket No. 93S-001EG, the Office of Consumer Counsel (OCC) requested that the ECA be eliminated and that fuel and purchased power costs be recovered in base rates. The Commission undertook an investigation of the ECA

[7] See section 4.4 for more information about the recovery of purchased power costs through automatic adjustment mechanisms.

in Docket No. 93I-702E. Decision No. C95-248 provided Commission guidance concerning further formal proceedings which should investigate the possibility of abolishing existing electric fuel cost recovery mechanisms as well as other alternatives.

On page nine of Decision No. C95-248 the Commission stated:

> Our review of the oral and written comments indicates that there is cause to believe that, in large measure, the historical reasons for implementing automatic adjustment clauses no longer exist.

At the conclusion of Docket No. 93I-702E, the Commission directed PSCo and WestPlains Energy[8] (WPE) to file formal pleadings to initiate an investigation of existing Electric Cost Adjustment mechanisms.

In 1995, PSCo filed an application (Docket No. 95I-464E) to investigate its ECA. That docket ultimately was consolidated with the New Century Energies (NCE) merger docket. The parties in that docket entered into a settlement which created an ICA mechanism. The ICA was structured so that 50 percent of the difference between the base cost of energy and the cost of energy in a particular test period was passed on to customers in the form of a rider to be applied during a subsequent recovery period. The ICA was viewed as an experiment and the settlement required PSCo to make a filing with the Commission before January 1, 2002, which would allow for a review of the incentive mechanism.

By Decision No.C00-393 in Docket 99A-373E, the Commission approved a settlement approving the merger of NCE and Northern States Power and also continuing the Incentive Cost Adjustment ("ICA") through December 31, 2002. The order states:

> Public Service has also agreed to a continuation of the Incentive Cost Adjustment (ICA) through the Test Year Period ending December 31, 2002. The ICA was a product of the 1996 Public Service/SPS merger settlement. The Commission believes the ICA has provided, and will continue to provide, a positive performance incentive.

On March 1, 2002, PSCo proposed to modify its ICA. In its application, Public Service projected a large deferred balance of recoverable ICA costs of approximately $148 million, by December 31, 2002. Under the existing ICA mechanism, those deferred costs would be collected from ratepayers over the period April 1, 2003, through March 31, 2004. Public Service expressed concern about the effect of such a large deferred balance on customers. By Decision No. C02-609 in Docket No. 02A-158E, the Commission accepted a settlement in which this deferred balance was recovered uniformly over a 34-month period from June 1, 2002, through March 31, 2005.

The Settlement in Docket No. 02A-158E also included a mechanism to address recovery of 2003 energy costs, because the existing ICA mechanism was set to expire on

[8] WestPlains Energy is referred to as Aquila later in this report.

December 31, 2002. The parties agreed that, in the event the new rates from the May 2002 rate case were not in effect on January 1, 2003, the Company would be entitled to put into effect an interim adjustment clause on January 1, 2003. That clause would collect 100 percent of the difference between its 2003 energy costs and the energy costs currently in base rates.

The settlement of the 2002 rate case addressed the recovery of PSCo's fuel costs for the years 2003 through 2006. By Decision No. C03-670 in Docket No. 02S-315EG, the Commission approved a settlement in which 2003 energy costs were recovered through an adjustment clause that passes through to retail customers 100 percent of 2003 energy costs.

In addition, Decision No. C03-670 provided that 2004-2006 PSCo energy costs were recovered through an incentive mechanism called the electric commodity adjustment (ECA) to be effective January 1, 2004. The test year for the ECA base was the 12-month period ending August 31, 2003. The incentive-sharing mechanism was structured so that the first $15 million difference (positive or negative) in any calendar year between the ECA base formula and actual energy costs was shared equally between retail customers and the Company. The next $15 million difference (positive or negative) was to be shared in a ratio of 75 percent retail customers and 25 percent Company. If the difference (positive or negative) in any calendar year exceeded $30 million, the excess amount of such difference beyond $30 million would be passed through to retail customers. This means that the maximum "profit" or "loss" to be absorbed by the Company in any one year through this incentive mechanism was $11.25 million. The remainder of any cost savings or cost increases would be passed through to retail customers. This mechanism ensured that the difference between ECA revenue paid by customers and prudently-incurred energy costs would never vary more that $11.25 million, either positive or negative.

By Decision No. C06-1379 in Docket No. 06S-234E, the Commission approved a settlement addressing the recovery of PSCo fuel costs during the period 2007 through 2010. The new quarterly ECA was intended to be simpler and more transparent than the previous mechanism. The settlement allows Public Service the opportunity to earn two incentives. The first incentive is based upon the increase in coal production compared to a benchmark target. The monetary savings from the coal production over the benchmark is shared in a ratio of 80 percent to customers and 20 percent to Public Service. The second incentive encouraged PSCo to pursue cost reductions through purchases of economical short-term energy. The total incentive payment to Public Service in any calendar year is not to exceed $11.25 million.

Aquila:

In response to Decision No. C95-248, WPE filed an advice letter to modify its ECA clause. By Decision No C96-19 in Docket No. 95S-292, the Commission approved a Settlement Agreement implementing an Incentive Cost Adjustment (ICA) mechanism which permitted WPE to recover 50 percent of the difference between the base cost of energy and actual cost of fuel and purchased energy charges. Demand charges for purchased power were excluded from WPE's ICA clause.

By Decision No. C03-697 in Docket No. 02S-594E, the Commission approved a settlement permitting Aquila to revise its ICA tariff which contained a 50/50 sharing mechanism. The new ICA sharing mechanism was 75 percent customers/25 percent Aquila, allowing Aquila to recover from or credit to customers 75 percent of the fuel and purchased energy cost changes recovered in its ICA tariff.

By Decision No. C94-999 in Docket No.04S-035E, the Commission approved a settlement permitting Aquila to terminate the ICA and replace it with an ECA. Unlike the ICA, the ECA allows Aquila to recover or to credit 100 percent of the fuel and purchased energy cost changes above or below its base energy cost.

Context: The Commission's electric fuel cost recovery policy has been shaped by the volatility of the underlying costs. According to Decision No. C95-248 in Docket No. 93I-702E, PSCo's original FCA was justified on the basis of the rapid fuel price increases experienced during the 1970s. For example, this order states that between 1970 and 1977, PSCo's fuel costs tripled from $.246 to $.749 per million BTU.

During the 1980s, the cost of fuel stabilized. According to Decision No. C95-248, the cost of generating electric power for PSCo declined an average of 1.37 percent per year for the years 1980 through 1993. However, the unit cost of purchased power increased an average of 4.14 percent per year for the same period. This relative fuel cost stability allowed the Commission to implement the ICA mechanisms for Public Service and WestPlains which specified that only a portion of the change in costs was passed on to customers.

Finally, the dawning of the new millennium was accompanied by increasing fuel cost volatility due to rapid increases in natural gas prices and the increased penetration of natural gas-fired generation in the total generation mix. This combination made it difficult to maintain the partial pass-through mechanisms and led to more targeted incentives based upon heat rates and coal plant availability.

Section 4.3 Gas cost adjustment (natural gas)

By Decision No. 89952 in Case No. 5721, the Commission stated that the purpose of gas cost adjustment (GCA) mechanisms was to permit rapid recovery of increased costs over which gas utilities have no control. In that decision, the Commission recognized that unless increased gas procurement costs were passed through to customers expeditiously, gas utilities would undergo serious earnings erosion. The Commission observed that such an erosion of earnings could jeopardize the ability of gas utilities to provide service.

In late 1993, the Commission opened Docket No. 93I-701G for the purpose of investigating the gas cost adjustment clauses of jurisdictional utilities. Decision No. C95-348 in that docket stated:

> The Commission concedes that at least two of the historical criteria used to justify the existence of the GCA appear to no longer be satisfied. However, when the record provided in this docket is viewed in its totality, it does not appear that there is adequate justification to initiate proceedings for the elimination or modification of the GCA at this time. Therefore, this investigation into gas cost and purchased gas adjustment clauses for regulated gas utilities is closed.

The Commission noted that prudence reviews of gas procurement activities were increasingly difficult to perform given the extremely complex gas procurement environment created by FERC Order No. 636. As a result, the Commission encouraged parties to participate in informal conferences intended to devise modifications to the GCA filing and review process. Staff and interested parties were directed to propose modifications to the GCA process to allow for an appropriate level of regulatory scrutiny to prevent abuses and inefficiencies associated with the gas procurement activities of jurisdictional gas utilities.

By Decision No. C97-367 in Docket No. 96R-089G, the Commission adopted GCA rules. This decision states:

> The intent of the proposed rules regarding GCAs (4 CCR 723-8) is to establish a standardized process that enables gas utilities to reflect changes in the cost of gas commodity and upstream services in rates charged for sales gas and gas transportation service. These proposed rules also establish a standardized process for the review of such costs by the Commission and other interested parties.

This led to new GCA rules which added the gas purchase plan and the gas purchase report to enhance Commission oversight of gas procurement practices.

<u>Context:</u> Gas commodity costs make up a large component of customers' total natural gas bill. This fact, combined with the substantial volatility in the well-head price of gas has led to general agreement that gas costs meet the criteria for inclusion in an automatic adjustment clause. The Commission adoption of GCA rules enhanced its ability to carry out its responsibility to insure that gas commodity expenses are just and reasonable.

<u>Section 4.4 Purchased capacity costs (electric</u>)

By Decision No C78-734 in Application No. 31012, the Commission authorized a Firm Purchased Power Adjustment (FPPA) mechanism to recover PSCo's firm power purchase costs. The Commission found that, due to a delay in the construction of PSCo's planned generating units, it was necessary for the Company to enter into a contract to purchase firm power to meet its system requirements. In the decision approving the FPPA, the Commission found that:

> In order to prevent further deterioration in Public Service's earnings and avoid the need for additional general rate case filings, it is essential that Public Service be permitted to recover, as fully and in as timely a manner as possible, the incremental cost of the firm purchased power needed to meet its customers' requirements.

The FPPA remained in effect until 1980 when the Commission combined the FPPA with the fuel cost adjustment mechanism to create the Electric Cost Adjustment (ECA) mechanism. In the decision approving the ECA (Decision No. C80-1592 in Application No. 32603), the Commission found that:

> Basically, Public Service's ECA proposal incorporates its current operative FCA and FPPA proposals, together with the additional cost tracking of non-firm purchased power and transportation costs. We find that Public Service's ECA program will reduce regulatory lag, inhibit attrition, and provide a greater degree of flexibility and response to changing costs.

The ECA recovered purchased capacity costs from its creation in 1980 through 1993. By Decision No. C92-1057 in Docket No. 91A-480EG, the Commission approved a settlement agreement modifying the ECA on the effective date of new rates from the 1992 general rate case. The settlement provided that capacity related costs of purchased power and capacity related wheeling costs were excluded from the calculation of base energy costs and not recovered through the ECA mechanism. All capacity associated purchased power expenses were to be recovered through base rates and changes were considered in general rate case filings. The settlement agreement recognized that PSCo may propose a mechanism to recover capacity-related costs of qualifying facilities.

In 1993, PSCo filed Docket No. 93S-151E to create a qualifying facility capacity cost adjustment (QFCCA) mechanism. The OCC recommended that if the Commission approved the QFCCA, then an earnings test also should be adopted. By Decision No. R93-1214, the Administrative Law Judge declined to adopt the earnings test. By Decision No. C93-1500, in response to exceptions, the Commission upheld the need for the QFCCA and adopted an earnings test. The record was sparse concerning precisely what the earnings test should be; therefore, the Commission ordered PSCo to make a new filing to incorporate a proposed earnings test and review process.

By Decision No. C95-1169 in Docket No. C95-041E, the Commission adopted an earnings test on a contingent basis. PSCo was required to implement a QFCCA earnings test on October 1, 1996, unless the Commission issued a decision that established a comprehensive form of performance-based incentive regulation ("PBR") for Public Service prior to September 1, 1996. The Commission structured the earnings test so that electric department excess earnings were to be shared equally between shareholders and ratepayers.

In 1995, PSCo filed an application to merge with Southwestern Public Service Company and to implement an incentive regulation plan, which included an earnings test mechanism. By Decision No. C96-1235, the Commission determined that the earnings test resulting from the merger should replace the earnings test from the QFCCA case. The Commission then terminated the QFCCA earnings test resulting from Docket No. 95S-041E.

By Decision No. C04-0476 in Docket No. 03A-436E, the Commission approved Public Service's application to implement a Purchased Capacity Cost Adjustment Rider (PCCA) for certain allowed contracts. The "allowed contracts" were those already reflected in the Company's base rates plus the contracts for the resources approved by the Commission in the Company's 1999 Electric Resource Plan.

By Decision C06-1379 in Docket No. 06S-234EG, the Commission approved a settlement modifying the existing PCCA. The settlement removed all purchased capacity costs from base rates, and allowed recovery of all of those costs through the PCCA rider on a forward-looking basis. The PCCA rider expires either when the final Comanche 3 rates take effect or December 31, 2010, whichever occurs first.

<u>Context:</u> The FPPA first was approved in the 1970s to address financial stress caused by the delay of the construction of a new power plant. Purchased capacity costs then were removed from the fuel cost recovery mechanism and a new clause was created to recover capacity costs associated with qualifying facilities, since utilities were mandated to make these purchases. The mechanism was later expanded to recover incremental capacity costs associated with the 1999 IRP, since these purchases were reviewed in as a part of the resource planning process. Finally, all capacity costs are now recovered through the PCCA.

<u>Section 4.5 Demand side management (electric and gas)</u>

<u>Electric DSM:</u> By Decision No. C90-1551 in Docket No. 90A-147E, the Commission approved a settlement agreement which authorized the creation of an electric demand side management cost adjustment (DSMCA) mechanism. The DSMCA was designed to recover demand side management (DSM) expenses, the amortized cost of DSM investments, a return on investment, and an incentive based on the cost and expected life of the DSM measure. The original DSMCA featured a seven-year amortization period and a ten-year financial incentive component based on a bounty of $240 per KW.

The Commission has modified the DSMCA several times since 1990. By Decision No. C93-38 in Docket No. 91A-480EG, the Commission approved a settlement which modified the DSMCA for programs developed as part of the DSM collaborative process. The modified DSMCA included a $200/kilowatt base bounty which was reduced depending on the cost of the individual DSM measure.

In Docket No. 93I-199EG the Commission approved a settlement which applied to the years 1994 and 1995. This settlement expressed the bounty payment on the basis of kilowatt-hour energy savings in addition to kilowatt capacity savings.

By Decision No. C95-1305 in Docket No 93I-199EG, the Commission approved PSCo's request to shorten the DSMCA investment amortization period from seven years to five years for those DSM investments made beginning in 1995 and to forego the financial incentive payments for DSM programs.

By Decision C96-697 in Docket No. 95A-625E, the Commission approved WestPlains' application for authorization to implement a DSMCA clause.

By Decision No. C05-049 in Docket No. 04A-214E, the Commission approved a settlement in which investments in new DSM programs were recovered over an eight-year amortization period.

HB 07-1037 (codified as C.R.S. §40-3.2-104) requires investor-owned electric utilities to achieve at least five percent reduction of retail energy sales and capacity savings by 2018, based on 2006 sales. HB 07-1037 further states that the Commission shall allow electric DSM investments an opportunity to be more profitable to the utility than any other utility investment that is not already subject to an incentive. Incentives include, but are not limited to: a premium rate of return on DSM investments; rapid amortization of DSM investments; utility retention of DSM net benefits; and cost recovery through a cost adjustment clause.

By Decision No. C08-560 in Docket No. C07A-420E, the Commission granted a new incentive mechanism for PSCo pursuant to HB 07-1037. The new incentive consists of the following: $2 million in after-tax revenue annually (approximately $3.2 million gross), for each year that PSCo achieves 80 percent of its DSM goal; allow for expensing of the DSM costs and recovery via the DSMCA on a prospective basis; and a performance benefit based on net economic benefits and the achievement of at least 80 percent of DSM targets.

<u>Gas DSM</u>

By Decision No. C92-1519, in Docket No. 91A-783E, the Commission authorized PSCo to implement a gas DSMCA. The gas DSMCA compensates PSCo for investments, costs, and incentives associated with the gas components of the Low-Income Energy Efficiency Assistance Program. The settlement established a partnership between PSCo and the Colorado Division of Housing. The original incentive component of the gas DSMCA was based on a bonus of $60 per residential unit created. The amount of money collected though the gas DSMCA was based on the same methodology of the electric DSMCA mechanism.

HB 07-1037 requires natural gas investor-owned utilities to spend two percent of a natural gas utility's base rate revenues on natural gas DSM programs. The Commission is directed to allow cost recovery and to provide an additional incentive. The incentive is either is 20 percent of the net economic benefits of the program or 25 percent of the DSM program expenditures, whichever is less.

Context: From the time of the establishment of the DSMCA in 1990 through the latest revision in 2008, the DSMCA has allowed recovery of expenses, rapid amortization of DSM investments and a return on the unamortized balance. While the amortization period has ranged between five and eight years (and has been replaced by expensing DSM costs), the overall DSMCA structure has been fairly stable.

The treatment of lost revenue has been a complex and controversial DSM issue. While the Commission has not approved an explicit lost revenue adjustment, various incentives have been used at times to partially recognize lost revenue. In the latest DSM decision, the Commission has allowed PSCo to retain a portion of the net economic benefits associated with DSM resources. This has the advantage of linking the financial reward to the demonstration of customer benefits.

Section 4.6 Air quality improvement (electric)

By Decision No. R99-678 in Docket No. 98A-511E, the Administrative Law Judge approved a stipulation establishing an Air Quality Improvement Rider (AQIR) to recover the air quality improvement costs that Public Service voluntarily incurred in reducing air emissions from three of its Denver/Boulder metro area power plants (Cherokee, Arapahoe, and Valmont).

The recovery of the air quality improvement costs was authorized by Senate Bill 98-142, codified as C.R.S. §40-3.2-101. This legislation allowed public utilities to enter into voluntary agreements with the Air Pollution Division of the Colorado Department of Public Health and Environment to reduce emissions below levels required by current environmental regulations. To induce this voluntary activity, the legislation provided for full recovery of air quality improvement costs that were prudently incurred up to a prescribed limit. The average rate impact from air quality improvement costs recovered by the public utility shall not be greater than the equivalent of 1.5 mills per kilowatt hour in any period, nor shall such costs exceed a total of $211 million calculated using 1998 present value dollars. The air quality improvement costs for a generating facility is to be recovered during a period of 15 years or less.

The stipulation in Docket No. 98A-511E specified that Public Service would file to implement its proposed AQIR on July 1, 2002. The 1999 Stipulation provided for the AQIR to go into effect on January 1, 2003.

By Decision No. C02-1422, in Docket 02S-485E, the Commission approved a settlement agreement approving tariff sheets to implement the AQIR to be effective on January 1, 2003. The settlement approved the rider and provided for resolution of four issues: the treatment of Arapahoe 1 & 2 depreciation expense; the removal of Arapahoe 1 & 2 from rate base; the appropriate discount rate to be used in calculating the AQIR; and the method for tracking the actual AQIR variable operation and maintenance expenses at the Company's plants receiving the emission control equipment.

Context: The AQIR could be viewed as a unique "one of a kind" recovery mechanism. It was established by the legislature to recover the costs to voluntarily reduce emissions from power plants to levels below that required by existing environmental regulation. No other mechanism to recover similar environmental control costs has been passed by the legislature.

However, the model of legislative incentives to encourage specific utility action has been repeated several times. Since the passage of the AQIR, the legislature created voluntary incentives for the construction of Integrated Gasification Combined Cycle generation units in Colorado and investments in transmission investments. In addition, the legislature passed legislation requiring investments in DSM and renewable resources along with incentives for cost recovery.

Section 4.7 Renewable energy standard (electric)

By Decision No. C97-203 in Docket No. 96A-401E, the Commission approved a stipulation allowing PSCo to implement an optional, experimental renewable energy service program (Windsource) and a tariff mechanism. Under the stipulation, customers could purchase renewable resources in 100 kilowatt hour blocks. The Company agreed to disclose that the price of this green power is based on market concepts instead of those traditionally used to develop regulated rates. The stipulation makes clear that the wind energy service program is being offered at shareholder risk.

By Decision No. C05-412 in Docket No. 04S-164E, the Commission approved a Windsource Settlement in which the parties agreed to continue current Windsource rates that were developed through the "value pricing" approach.

In November 2004, voters approved Amendment 37, making Colorado the first state in the country to pass a statewide ballot referendum requiring a renewable energy standard (RES). HB07-1281 expanded the RES beyond the requirements of Amendment 37. The RES for IOUs increased to five percent by 2008, 10 percent by 2011, 15 percent by 2015, finally requiring a level of 20 percent by 2020.

By Decision C05-1461 in Docket No. 05R-112E, the Commission established rules implementing Amendment 37.[9] Commission rules (4CCR 723, Rule 3660) allow investor-owned utilities to recover all prudently expended costs to comply with the RES through adjustment clauses. In addition, the rules specify that a utility can earn extra profit on its ownership investment in specific renewable resources based on the net economic benefits provided to customers. For these specific renewable resources investments, the utility is entitled to a return equal to its most recent authorized rate of return on rate base plus a bonus limited to 50 percent of the of the net economic benefit, provided that the utility is in compliance with the rules implementing the RES. If the utility's investment in a specific renewable resources does not provide a net economic

[9] Note that the Commission modified its RES rules by Decision No. C07-622 in Docket No. 07R-166E to reflect the passage of HB07-1281.

benefit to customers, the utility is entitled to a return equal to its most recent authorized rate of return on rate base.

HB07-1281 established a retail rate impact of two percent of the total electric bill annually for each customer. The retail rate impact is net of alternative sources of electricity supply from non-renewable resources reasonably available at the time of the determination.

Context: Amendment 37 and HB07-1281 allow utilities to recover costs associated with the RES through an adjustment clause and provide an incentive based on the net economic benefit associated with renewable resources.

It should be noted that the Commission approved the utility purchase of wind resources in previous resource acquisition processes. By Decision No. C01-295 in Docket No. 99A-549E, the Commission ordered Public Service to acquire 162 MW of wind energy. The Commission stated:

> We find that adding Enron's Lamar wind energy bid to PSCo's preferred resource plan is in the public interest and comports with the IRP rules. This determination is based solely on our finding that the acquisition of the Lamar facility will likely lower the cost of electricity for Colorado's ratepayers. After a careful analysis of the economics of the wind bid, we find that it is justified on purely economic grounds, without weighing other benefits of wind generation that could be considered under the IRP rules.

Section 4.8 Transmission costs (electric)

SB07-100 requires investor owned utilities to submit a filing by October 31, 2007, and each subsequent odd numbered year, to: designate energy resource zones; develop transmission construction plans to deliver power consistent with the development of energy resources to such zones; consider how transmission can be provided to encourage local ownership of renewable energy facilities; and submit plans and Certificates of Public Convenience and Necessity (CPCN) to the Commission. The Commission is to approve the CPCNs if it finds that the construction or expansion is necessary to ensure reliable electricity delivery or enable the utility to meet the RES standards as well as meeting its usual CPCN standard. The bill requires the Commission to issue a final order within 180 days of the CPCN application or the application is approved.

SB07-100 provides incentives for cost recovery:

> To provide additional encouragement to utilities to pursue the construction and expansion of transmission facilities, the commission shall approve current recovery by the utility through the annual rate adjustment clause of the utility's weighted average cost of capital, including its most recently authorized rate of return on equity, on the total balance of construction

> work in progress related to such transmission facilities as of the end of the immediately preceding year. The rate adjustment clause shall be reduced to the extent that the prudently incurred costs being recovered through the adjustment clause have been included in the public utility's base rates as a result of the commission's final order in a rate case.

By Decision No. C07-1085 in Docket No. 07A-339E, the Commission approved PSCo's initial Transmission Cost Adjustment. This decision addressed specific issues associated with the transmission rider such as: the costs to be included in Public Service's 2008 Transmission Cost Adjustment Rider; whether average or year-end rate base should be used as the basis of the calculation of the incremental revenue requirement of the TCA rider; the interest rate to be applied on any over-collections of rider revenues; and reporting requirements associated with each electric power transmission project.

<u>Context:</u> This legislation provides incentives for increased investment in Colorado transmission infrastructure. A robust electric transmission system contributes to greater electric reliability, allows greater access to renewable resources in order to meet Colorado's renewable energy standard, and provides access to a larger portfolio of electric generation resources.

Section 5
Price Volatility Management and Trading

Section 5.1 Natural gas price volatility management

Beginning in the late 1990s, Colorado natural gas utilities experienced rapid and large increases in the cost of natural gas purchased in wholesale markets. Colorado gas utilities applied for multiple increases in their gas cost adjustment clauses. These requests were consistent with the GCA Rules and were approved by the Commission.

By Decision No. C01-207 in Docket No. 01R-083G, the Commission adopted an emergency rule amending Rule 5.3.3 of the GCA Rules to require that Gas Purchase Plans specify the measures each utility considered to reduce customers' risk of gas price volatility for the upcoming Gas Purchase Year. The Commission adopted an emergency rule so that utilities had sufficient time to consider price volatility management measures in their Gas Purchase Plans (GPP) to be filed on June 1, 2001.

By Decision No. C02-181 in Docket No. 01R-346G, the Commission made permanent those changes that were adopted as emergency rules in Docket No. 01R-083G. The permanent rules clarified that costs related to gas price volatility risk management may be included for recovery through the GCA if allowed by tariffs, subject to the prudence review standard.

By Decision No. C04-1112 in Docket No. 02A-267G, the Commission approved a settlement allowing PSCo to recover its purchased gas costs through a monthly GCA process rather than the annual GCA process. The settlement established procedures for Commission pre-approval of Public Service's annual Gas Price Volatility Mitigation (GPVM) plans applicable to its natural gas sales services. As part of the GPVM plan, the parties agreed to establish certain hedging targets and parameters for Public Service to follow during the four Gas Purchase Years subject to the settlement, covering the period from July 1, 2005 through June 30, 2009. The purpose of the GPVM plan is to provide a robust hedging program intended to reduce the level of gas price volatility experienced by Public Service's customers. Under the GCA rules, the Commission does not approve the GPP, but uses it as a part of its after-the-fact prudence evaluation. The settlement establishes procedures for the merits of the GPVM plan to be reviewed and approved by the Commission for reasonableness in advance of the gas purchase year. These procedures are similar to, and were negotiated by the Parties in conjunction with, parallel procedures adopted by the Commission for approval of Public Service's GPVM Plan for its electric generation fuel procurement activities in Docket No. 04A-045EG.

Context: The increase in both the price and the volatility of natural gas in the late 1990s ended a period of relatively stable gas prices. In response, the Commission ordered gas utilities to consider using hedging mechanisms to provide for greater gas price stability. Such mechanisms include physical gas storage, fixed price forward contracts, and financial instruments such as puts, calls, collars, and swaps.

Hedges are a form or insurance that reduces natural gas customers' risk of gas price volatility, but also may be more costly over the long-term compared to simply purchasing gas at indexed prices. The Commission's evaluation of the prudence of hedging techniques must be based on the reasonableness of the overall hedging strategy rather the performance of any particular element of the hedging program.

Section 5.2 Electricity price volatility management

By Decision No. C03-670 in Docket No. 02S-315EG, the Commission approved a settlement which established a hedging program to reduce the exposure of Public Service's electric sales customers to fluctuations in the price of gas used to generate electricity. The settlement capped the net gas hedging costs passed through to retail customers at $15 million for each period of May 1 through April 30. The net gas hedging costs includes: all premium costs; all settlement costs in excess of the Commission-approved floor price; and all gains from gas hedging transactions.

By Decision No. C04-1281 in Docket No. 04A-045EG, Commission approved a settlement which established a strategy for mitigating the volatility of natural gas prices for the natural gas that Public Service uses for its electric generation facilities. In the settlement the parties requested that the Commission approve: a seasonal strategy and a long-term strategy; the floor price and maximum hedging budget; the gas purchase volume to be included in the Price Volatility Mitigation Plan; and the timing for implementation.

Context: The volatility of natural gas prices has a large impact on electricity costs. In the past decade the penetration of natural gas generation has increased substantially, thus strengthening the link between natural gas prices and retail electricity prices. The same factors which led the Commission to require gas utilities to consider measures to reduce customers' risk of gas price volatility also applies in the case of natural gas used in electric generation.

Section 5.3 Electricity Trading

By Decision No. R00-830 in Docket No. 99A-557E, Staff entered into a settlement which allowed PSCo to engage in short term wholesale electricity trading through December 31, 2002. The settlement required that 50 percent of the net margins from trading be shared with retail customers and that no net negative margins by passed on to retail customers. Short-term wholesale sales were defined as sales up to one year in length.

By Decision No. C03-670 in Docket No. 02S-315EG, the Commission approved a settlement which extended the terms and conditions of the Settlement in Docket No. 99A-557E through December 31, 2004, with some modifications for the calendar years 2003 and 2004. Significant modifications include: the ratemaking treatment of the costs of conducting electric trading operations; separate margin sharing for the GenBook and

PropBook[10] operations;[11] establishment of separate general ledger accounts to track the GenBook and PropBook costs and revenues; the development of business rules that the Company would follow through December 31, 2004; a procedures audit of PSCo's GenBook and PropBook electric trading operations; Company agreement to file an application in January 2004 for Commission review of its electric trading operation; and Public Service's agreement to provide funds to hire a consultant selected by the Trial Staff and the Office of Consumer Counsel (OCC) in order to provide them with technical advice and consulting services regarding prospective changes that should be made, if any, to the Colorado regulatory treatment of Public Service's trading activities.

By Decision No. C04-1208 in Docket No. 04A-050, the Commission approved a settlement which authorized Public Service to continue electric commodity trading. The settlement required: the sharing of positive trading margins from the GenBook and the PropBook agreed to in the Docket No. 02S-315EG settlement agreement would continue through calendar year 2006; beginning November 15, 2004, Public Service agreed to conduct its electric commodity trading operations in accordance with the revised business rules; and the development of plans and reports to assist Staff in auditing the Company's compliance with the revised business rules. Finally, the settlement required PSCo to file an application by April 1, 2006, addressing the Company's proposed regulatory treatment of energy costs incurred after December 31, 2006 and to also address the mechanism for returning the customer's share, if any, of the trading margins earned in calendar year 2006.

By Decision No. C06-1379 in Docket No. 06S-234EG, the Commission approved a settlement that continued short-term energy trading under all the terms and conditions set forth in the settlement agreement approved in Docket No. 02S-315EG, under the business rules approved by the Commission in the trading docket. The settlement altered the sharing of the gross margins. Public Service is to share with ratepayers the retail jurisdictional share of aggregated annual positive gross margins over and above $1,023,070 from both the Gen Book and Prop Book. The sharing percentages of aggregated annual positive gross margins is Gen Book – 80 percent to ratepayers and 20 percent to Public Service; and, Prop Book – 20 percent to ratepayers and 80 percent to Public Service.

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[10] A Gen book transaction is defined as a short term electric energy sale that is generated from units owned by Public Service, that is available to Public Service under long term contracts, or that is acquired in a short term market purchase. Prop book transactions are purchases and sales of electric energy on the wholesale market from and to entities that are not related to Public Service or to any other Xcel Energy operating company.

[11] For the Gen book, retail customers receive the first $1.74 million; the Company retains the next $1.74 million; and the remaining gross margin was shared 60 percent retail customers/40 percent Company. For the Prop book, the Company retains the first $1 million; the remaining gross margin was shared 40 percent retail customers/60 percent Company. No net losses are shared with retail customers.
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Context: Opportunities for short-term electricity trading by regulated utilities increased in the late 1990s due to FERC initiatives which created a more robust wholesale electricity market. Generation (Gen) Book transactions are a traditional utility activity. It has been a long-established practice for utilities to buy power for customers when it is cheaper than generating and to sell power when economically advantageous and not needed by native load customers. The changes to the margin-sharing percentages reflect this situation. After beginning with equal generation book sharing in the 2000 settlement, the latest agreement specifies that 80 percent of net positive margins are shared with ratepayers. Prop Book transactions have a weaker link to regulated utility operations; therefore, only 20 percent of any net positive margins are shared with ratepayers.

Section 6
Resource Acquisition Incentives

Incentives can take several forms. The types of incentives discussed in this report to this point generally take the form of financial carrots and sticks either to encourage or discourage some utility behavior. The next two subsections discuss a different type of incentive – a legislative mandate to deploy minimum levels of DSM and renewable resources in Colorado.

Section 6.1 HB07-1037 - DSM

HB 07-1037 (codified as C.R.S. §40-3.2) requires investor-owned electric utilities to achieve at least a five percent reduction of retail system peak demand and at least a five percent reduction in energy sales and capacity savings by 2018. The savings are based upon 2006 peak demand and sales.

By Decision No. C08-560 in Docket No. 07A-420E, the Commission approved DSM goals for Public Services which are significantly higher than the minimum requirements of HB07-1037.

In addition, HB 07-1037 requires natural gas investor-owned utilities to spend at least one-half of one percent of a natural gas utility's revenues from full service customers on natural gas DSM programs. The target for a particular year is based upon revenues from the previous year.

By Decision No. C08-248 in Docket No. 07R-371G, the Commission approved gas rules implementing HB07-1037. The rules state:

> The utility's annual expenditure target for DSM programs shall be, at a minimum, two percent of a natural gas utility's base rate revenues (exclusive of commodity costs), from its sales customers in the 12-month calendar period prior to setting the targets, or one-half of one percent of total revenues from its sales customers in the 12-month calendar period prior to setting the targets, whichever is greater (4CCR 723, Rule 4753(g)).

Context: See Context at the end of Section 6.2.

Section 6.2 HB07-1281 – Renewable resources

In November 2004, Colorado became the first state in the country to pass a statewide ballot referendum requiring a renewable energy standard (RES). Amendment 37 applied to Colorado's largest utilities and required that a portion of their retail electricity sales be supplied by renewable sources. The RES was set at a minimum of three percent in 2007, increasing to six percent by 2011 and reaching a final level of 10 percent by 2015.

Amendment 37 applied to the state's two investor owned utilities (IOU), Public Service and Aquila, as well as municipal utilities and rural electric cooperatives with more than 40,000 customers. Amendment 37 allowed utilities to opt out of the RES through a majority vote of their customers.

HB07-1281 expanded the RES beyond the requirements of Amendment 37. The RES for IOUs increased to a minimum of five percent by 2008, 10 percent by 2011, 15 percent by 2015, and reaching a final level of 20 percent by 2020. In addition, HB07-1281 eliminated the opt-out for municipal utilities and rural electricity cooperatives. The RES for rural electric cooperatives and municipal utilities with more than 40,000 customers is one percent by 2008, three percent by 2011, six percent by 2015, and reaching a final level of 10 percent by 2020. HB07-1281 retained the requirement that at least four percent of the mandated renewable energy is derived from solar electric generation technologies (applicable to investor-owned utilities). At least one-half of this four percent must be derived from solar electric technologies located on-site at customer facilities. In addition, HB07-1281 retained the provision that each kilowatt-hour of electricity generated in Colorado counts as 1.25 kilowatt-hours for purposes of compliance with this standard.

HB07-1281 requires the Commission to establish a maximum retail rate impact of two percent of the total electric bill annually for each customer. The retail rate impact is calculated net of new alternative sources of electricity supply from non-eligible energy resources that are reasonably available at the time of the determination.

The Commission evaluates a utility's RES performance through two separate filings: (1) a Compliance Plan; and (2) a Compliance Review Report. An investor-owned utility is required to file a compliance plan annually, on or before July 1, detailing how it intends to comply with the RES Rules during the upcoming year (4CCR 723, Rule 3657).

Decision No. C08-559 in Docket No. 07A-462 approved Public Service's 2008 compliance plan.

By Decision No. R08-385 in Docket No. 07A-356E, the Administrative Law Judge approved a settlement agreement approving Aquila's 2008 compliance plan

<u>DSM and Renewable Context</u>: In 2006, more than 70 percent of Colorado's electricity was generated from coal. The legislative mandate that utilities acquire minimum levels of DSM and renewable resource promotes greater diversification of Colorado's electric generating mix. In addition, these resources help reduce the risk of fossil fuel price volatility, reduce air emissions, reduce water use, and promote the achievement of the goals contained in Governor Bill Ritter's recently announced Climate Action Plan. According to many studies, DSM resources have the potential to be the least expensive resource available to meet future capacity and energy needs.

Section 6.3 IGCC option

HB06-1281 directed the PUC to consider voluntary proposals by Colorado electric utilities to develop, fund, and construct integrated gasification combined cycle (IGCC) generation facilities. The bill's intent is to demonstrate the feasibility of IGCC technology with the use of western coal at high altitude and with carbon dioxide (CO2) sequestration. The legislation defines an IGCC facility as "one that converts coal to gaseous fuel from which impurities are removed prior to combustion, uses the gas in a combustion turbine and captures waste heat to drive a steam turbine to produce electricity." An IGCC project is not to exceed 350 MW nameplate capacity. However, a larger plant is allowed if necessary to obtain federal cost-sharing, grants or tax benefits, or other financial opportunities including joint development with other utilities. The project must: be located in Colorado, demonstrate the capture and sequestration of "a portion" of the project's carbon dioxide emissions, and monitor the fate of CO2 captured from the facility.

A public utility may apply to the Commission for a Certificate of Public Convenience and Necessity (CPCN) and cost recovery for an IGCC project. A public utility is entitled to fully recover the costs that it prudently incurs in planning, developing, constructing and operating an approved IGCC project, net of any federal or state funds received through a separate rate adjustment rider, from its Colorado retail customers. The utility is granted current recovery of funds during the construction and start-up phases of the project at the utility's weighed-average cost of capital. In addition, the utility shall recover, through the rate rider, any additional costs for purchased power as a result of outages of the IGCC project.

Public Service stated in its Resource Plan (Docket No. 07A-447E) that, while it believes that IGCC is technically feasible and carbon sequestration opportunities exist in Colorado, it will not seek to acquire an IGCC before 2016.

Context: The demonstration of successful CO2 sequestration from an IGCC facility would yield benefits for electricity customers. IGCC technology holds the potential for the efficient use of abundant and relatively inexpensive coal in a combined cycle plant to generate electricity. IGCC may result in a more cost-effective method to capture CO2 emissions from a fossil fuel-fired generating facility.

The regulatory treatment provided to utilities constructing an IGCC facility are intended to balance the risks associated with this new technology. The risks include: construction and operational risks associated with a new technology, the likelihood of delays and higher costs compared to more mature technology. In addition, carbon sequestration presents risks of higher costs, delay, regulatory uncertainty and legal risks of long term responsibility of captured CO2.

Section 6.4 Natural gas partial decoupling

Under traditional regulation, utilities recover both fixed and variable costs of electricity production through rates based either on historical or forecasted levels of sales, expenses, and investments. Once these rates are determined, the companies' revenues are directly dependent on the amount of kilowatt-hours sold. Under this system, a reduction in kilowatt-hour sales due to the success of DSM programs can be harmful to a company's financial performance, until rates are reset in a subsequent rate case. Decoupling takes the form of a rider or attrition allowance in which authorized per customer margins are subject to a true-up mechanism to maintain or cap a given level of revenues or revenues per customer.

Decoupling has been discussed for several decades in Colorado. Decision No. C91-918 settled a complaint case (Docket No. 90F-226E) filed by the OCC against Public Service, alleging that the company's rates were unjust and unreasonable. Public Service filed a rate case (Docket No. 91S-091EG) which was consolidated with Docket No. 98F-266E. The settlement in these cases created a new docket (91A-480EG) to address decoupling revenues from sales and regulatory incentives to encourage demand side management programs. By Decision No. C93-38 in Docket No. 91A-480EG, the Commission directed Staff and Public Service to develop a decoupling mechanism for consideration by the Commission in Phase I of the 1993 Public Service rate case (Docket No. 93S-001EG).

Decision No. C93-325 severed all issues related to decoupling and other DSM incentives from the 1993 Public Service rate case into Docket No. 93I-199EG. A technical working group was created to analyze the effects of three proposed decoupling mechanisms. The emergence of wholesale and retail competition altered the decoupling investigation and led to a discussion of the future of Public Service's regulated DSM activities. By Decision C95-1305 in Docket No. 03I-199EG, the Commission closed the investigation into decoupling and demand-side management incentives for Public Service and ordered modifications to the DSMCA as a vehicle to fund new DSM programs (see section 4.5).

By Decision No. C07-568 in Docket No. 06S-656G, the Commission approved a settlement which established a Partial Revenue Decoupling Adjustment (PRDA) pilot program for Public Service's residential gas customers. The mechanism is designed to reduce the impact of changes in customer use on Public Service's revenues and earnings. Specifically, the proposed mechanism would counter the financial impact of changes in customer use driven by factors other than weather (such as increased appliance efficiency, customer conservation efforts, and customer responses to price changes). This mechanism would adjust the rates of residential customers to reflect actual average residential usage, normalized for weather effects, compared to the average customer consumption used to calculate rates in the rate case. Public Service will adjust rates each year through the decoupling rate adjustment mechanism to recover reduced weather-normalized revenues due to reduced usage per customer to the extent that revenue per residential customer declines more than 1.3 percent per year. The PRDA was approved as a three-year pilot with the first base period July 2007 through June 2008.

Context: As noted in Section 4.5, successful utility DSM programs raise utility concerns with lost revenue. One solution to the lost revenue problem is "decoupling," meaning that utility profits are not dependent on the level of sales. Decoupling, by itself, does not create a positive economic incentive for utilities to promote DSM, but removes the utility disincentive associated with DSM programs. Decoupling has been recently adopted in several states, but is subject to several criticisms. It is argued that decoupling sends mixed price signals to consumers. For example, in the short-run, conservation efforts result in higher future rates, while increased consumption produces bill credits. In addition, it is argued that decoupling is overly broad. Depending upon the design of the decoupling mechanism, the utility is made whole for reduced sales (business cycle and weather) that go beyond DSM programs.

The PRDA mechanism may eliminate the disincentive for Public Service's conservation efforts. In addition, since gas usage per customer recently has been declining, the PRDA could also mitigate regulatory lag, resulting in fewer filed rate cases.

Section 6.5 Treatment of CWIP

The regulatory treatment of carrying charges (interest costs and an equity return) on construction work-in-progress (CWIP) has implications for resource acquisition. The Commission traditionally has not allowed current earnings on CWIP, but rather, financing costs are accumulated as Allowance for Funds Used During Construction (AFUDC) and earnings are allowed when the plant is put in service and deemed to be "used and useful." The used and useful principle provides the utility with incentives to complete the project on time and to finance the construction efficiently. In addition, it is argued that current earnings on CWIP violates the principle of intergenerational equity, since it is unfair to have current customers pay for a plant that does not benefits them.

As a general matter the Commission has not allowed current earnings on CWIP, but has sometimes granted such treatment during periods when a utility was suffering from financial stress.

By Decision No. C05-049 in Docket No. 04A-214E, 04A-215E, and 04A-216E, the Commission approved a settlement which entitled Public Service to current earnings on CWIP associated with the Comanche 3 project, dependent upon the rating on the Company's senior unsecured debt.

Context: A regulatory treatment of CWIP is controversial. Deferring earnings on a large generating plant places considerable financial strain on a utility during large construction programs. The Colorado legislature has shown willingness to grant current earnings on CWIP for particular resources. SB07-100 provided that any utility constructing transmission facilities receives current earnings on CWIP, as well as timely recovery of these costs, through a rate adjustment clause. In addition, HB06-1281 provides that any utility constructing an IGCC project receives this regulatory treatment.

Section 7
Quality of Service

Section 7.1 Electric industry quality of service

Public Service Company of Colorado:

By Decision C96-1235 in Docket No. 95A-531EG (the Public Service – Southwest Public Service merger) the Commission approved a settlement which established the first electric Quality of Service Plan (QSP) for Public Service. The QSP applied to years 1997 through 2001. Three benchmarks were established: (1) customer complaints received by the Commission; (2) telephone response by the company's customer inquiry center; and (3) electric service unavailability. The QSP established a maximum bill credit of $1 million each for the customer complaint and telephone response time components and $3 million for the electric service unavailability in the first year, with penalties potentially increasing each year. By the fifth year, the maximum penalty for electric service unavailability could total $6.6 million.

The QSP was designed to maintain historical levels of service by discouraging cost savings at the expense of quality of service. It was recognized that the appropriateness of specific service quality measurements and the expected performance targets for those measurements within the electric utility regulatory environment was an emerging area. To appropriately reflect this circumstance, the QSP contained a provision that any party, and the Commission, may initiate a proceeding to modify it.[12]

The parties to the QSP settlement were unable to agree whether a reward should be included in the QSP mechanism for Public Service. The majority, in Decision C96-1235, agreed that Public Service's QSP should include the opportunity for the Company to earn rewards but directed that the actual design of the reward mechanism was to be addressed in a subsequent proceeding. By Decision R97-767 in Docket 97A-145E, the Administrative Law Judge granted an incentive with increasing rewards (to a maximum of $3 million per year) as the regional electric service reliability (SAIDI) measure improved.

By Decision No. R98-10101 in Docket No. 95A-531EG, the Administrative Law Judge accepted a settlement which eliminated the QSP rewards for the years 1999 through 2001.

By Decision No.C00-393 in Docket No. 99A-373E, the Commission approved a settlement in the New Century Energies - Northern States Power merger which extended the QSP for the years 2002 through 2006. Public Service agreed to continue the

[12] For example the benchmarks and exclusion process was modified by Decision R01-1034 in Docket No. 00M-632EG, and again by Decision C05-1438 in Docket No. 05A-268E

standards for measuring the quality of its electric services and to increase bill credits[13] imposed if those standards are not met. The purpose was to help ensure that the merged Company did not pursue cost savings at the expense of the quality of service provided to Colorado's consumers.

In addition, this settlement provided for development of a quality of service plan for Public Service's gas operations to become effective in 2001. For more information on natural gas QSP, please refer to Section 7.2.

By Decision No. C04-1566 in Docket No. 03I-134E and Docket No. 04I-098E, the Commission approved a settlement in which PSCo agreed to accelerate its feeder and underground cable repair and replacement programs by investing an additional $12 million in 2005 over and above the $13 million it has budgeted for this purpose. It also committed to spend an additional $13 million in 2006 and 2007, over and above the $13 million in each of these years it expects to budget for cable replacement and repair. This resulted in an additional expenditure of $38 million over three years. Under the terms of the settlement, these additional expenditures will be recoverable through PSCo's utility rates.

By Decision No. C05-1438 in Docket No. 05M-188E and Docket No. 05A-288E, the Commission approved a settlement in which Public Service agreed to invest an additional $11 million toward improving reliability. This $11 million is an incremental capital investment during 2006, above the present budget. This investment is targeted at specific outage problems in the electric distribution system such as underground residential distribution cable.

Docket No. 06I-118E is the Commission's investigation of PSCo's controlled electricity outages which occurred on February 18, 2006. More than 371,000 Colorado electric customers lost power for an average of more than 41 minutes on one of the coldest days in several years. In this docket, PSCo filed its initial report to the Commission concerning this event on June 15, 2006. Commission Staff filed its initial report regarding its investigation on July 7, 2006, including specific concerns and recommendations for improvements. On August 11, 2006, PSCo filed its responses to the recommendations contained in the Staff report.

By Decision No. 06-1303 in Docket No. 05A-288E, the Commission approved a settlement (SAIDI Settlement) which extended Public Service's electric QSP for the period 2007-2010. The Commission stated:

> While the QSP was originally implemented for merger considerations, the program has nonetheless become an essential component of any incentive regulatory program. In light of these concerns we again note that we appreciate the efforts of the parties to continue the QSP program, and find

[13] The annual maximum bill credits were $3 million each for customer complaints and telephone response. The annual maximum bill credits for electric service unavailability was $9 million.

> that the additional reporting requirements are a critical step in maintaining a fair and comprehensive QSP program over the long run. Further, in the future, parties should consider a direct link to the QSP requirements as a part of any incentive regulatory program(s) implemented at that time.

The SAIDI Settlement provides for total bill credit exposure of $11.064 million, before tax gross-up. The annual bill credit for customer complaints remains at $1 million with a threshold of 0.8 complaints per 1,000 customers. The annual bill credit for telephone response also remains at $1 million with a threshold of 70 percent of calls answered in 45 seconds. The SAIDI settlement established annual bill credits for regional system reliability at $7.04 million and $1 million each for electric service continuity and electric service restoration. In addition, the Commission stated that it is prudent for Public Service to have a replacement QSP program in place and required Public Service to file an application to continue its QSP program by January 31, 2010.

Aquila:

By Decision No. R05-313 in Docket No. 04A-046E, the Administrative Law Judge approved a settlement which established the first QSP for Aquila's electric operations. The QSP will be in effect for five years,[14] beginning July 1, 2005. The settlement provided for maximum bill credits of $125,000 for the first year, with $25,000 based upon the measure for customer complaints, $25,000 for telephone response time, and $75,000 for electric service unavailability. These initial amounts are subject to a ratchet mechanism.

Context: The original motivation for the adoption of the QSP was concern that the PBR mechanism may lead to deterioration in service quality. The PBR mechanism provides cost reduction incentives which may result in reduced service quality, assuming that service quality and costs are positively related to one another. In addition, there is concern that local operating utilities may have greater difficulty obtaining resources to invest in distribution facilities from the parent company.

Section 7.2 Natural gas industry quality of service

By Decision No. C01-1330 in Docket No. 99A-377EG, the Commission approved a settlement which established a QSP for Public Service's gas department. The stipulation provides that the Gas QSP will be in effect from 2002 to 2007 and will include two components: a Leak Permanent Repair (LPR) service metric and a meter reading error (MRE) metric. The LPR metric consists of two components: 1) the total system average of the total time to permanently repair a leak and the total system average for the top 10 percent of LPR repair time. If either of these two subcomponents is exceeded, a bill credit is applied to gas customers. The MRE metric is based upon a percentage of the

[14] According to the settlement, if Aquila attains an investment grade rating on its senior unsecured debt, and has met the benchmarks for adequacy on all three quality of service measures for three consecutive performance years, Aquila may file an application requesting that the Commission terminate the plan.

number of manual meter reading errors found by customers relative to the number of meters read.

The initial total maximum bill credit was set at $1 million dollars. If a service metric is exceeded, a ratchet mechanism could increase the potential maximum total bill credit to $3 million dollars in $500,000 dollar increments, or ratchet the bill credit back to the minimum total bill credit of $1 million dollars in $500,000 dollar increments. The possible bill credit was allocated 90 percent to the LPR metric and 10 percent to the MRE metric.

According to Public Service's current gas tariff, the gas QSP will be in effect through 2010, citing Decision No. C06-1303.

<u>Context</u>: The gas QSP consists of only two measures, leak repair and meter reading errors. It should be pointed out that under PSCo's electric QSP; both the telephone response and customer complaints measure possible deterioration in gas customers' service quality.

In the design of the gas QSP, some parties suggested that gas odor response time should be included. The Commission decided that while this measure captures both an element of safety and quality of service, it is primarily a measure of safety and should not be included in a quality of service program.

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Section 3: Incentive Regulation - Earnings Sharing (electric and natural gas)

Decision	*Docket*	*Summary*
C92-854	90A-665T	Established an Alternative Form of Regulation (AFOR) for US WEST containing an earnings sharing plan.
C95-1169	95S-041E	Required PSCo to implement a QFCCA earnings test, unless incentive regulation in place by September 1, 1996.
C96-1235	95A-531EG	PSCo - SPS merger established PSCo electric earnings sharing through 2001. Replaced QFCCA earnings test.
C00-393	99A-373EG	NCE - Northern States Power merger. Settlement extended PSCo's electric earnings sharing mechanism through 2006.
C07-1008	07A-388G	Settlement establishes 2007 earnings sharing for Atmos Energy. Customer share begins at 25% if ROE exceeds 10.25%.

Section 4.2 Fuel costs (electric)

Decision	*Docket*	*Summary*
		Public Service Company of Colorado
89225	5700	Commission stated reasons for creating PSCo's fuel cost adjustment (FCA)
80-1592	32603	Commission allowed PSCo to combine its existing FCA and its FPPA into a new mechanism called the ECA.
C93-1346	93S-001EG	OCC requested that the ECA be eliminated and that fuel and purchased power costs be recovered in base rates.
C95-248	93I-702E	Commission ECA investigation - the historical reasons for automatic adjustment clauses may no longer exist.
C96-111	95I-464E	PSCo filed a docket to investigate its ECA - it was consolidated with the NCE merger docket.
C96-1235	95A-531EG	PSCo - SPS merger established PSCo ICA: 50/50 sharing of difference between base and actual energy costs.
C00-393	99A-373E	NCE - NSP merger. Settlement extended PSCo's ICA through 12/31/2002.
C02-609	02A-158E	Established Interim Adjustment Clause to recover 100% of 2003 energy costs; resolves large deferred balance.
C03-670	02S-315EG	Modified the ICA - created an incentive-based Electric Commodity Adjustment for the period 2004-2006.
C06-1379	06S-234EG	Modified the ECA. ECA expires on December 31, 2010, or when Comanche 3 comes on line, whichever occurs first.
		Aquila Electric
C96-19	95S-292E	Settlement created the Incentive Cost Adjustment: 50/50 sharing of the difference between base and actual energy costs.
C03-697	02S-594E	Modified the ICA sharing mechanism prospectively to 75% customers / 25% shareholders.
C04-999	04S-035E	Ended the ICA sharing mechanism. Implemented a traditional Energy Cost Adjustment.

Section 4.3 Gas cost adjustment (natural gas)

Decision	*Docket*	*Summary*
89952	5721	Commission stated that the purpose of gas cost adjustment (GCA) mechanisms
C95-348	93I-701G	Commission docket to investigate the gas adjustment clauses of jurisdictional utilities.
C97-367	96R-089G	Commission adopted GCA rules - standardized process for the review of gas cost adjustment filings.

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Section 4.4 Purchased capacity costs (electric)

Decision	*Docket*	*Summary*
C78-734	No. 31012	Commission authorized a Firm Purchased Power Adjustment (FPPA) mechanism.
C80-1592	No. 32603	Commission authorized the ECA which combined the fuel cost and FPPA mechanisms into a single tariff.
C92-1057	91A-480EG	Commission accepted a settlement removing capacity costs from the ECA.
C93-1500	93G-151E	Commission adopted an earnings test as a condition for granting a Qualifying Facility Cost Adjustment mechanism.
C04-476	03A-436E	Commission approved a Purchased Capacity Cost Adjustment (PCCA) for certain purchased power contracts.
C06-1379	06S-234EG	Modified PCCA to recover all projected capacity costs. PCCA expires earlier of: Comanche 3 rates or end of 2010.

Section 4.5 Demand side management (electric and gas)

Decision	*Docket*	*Summary*
		Electric DSMCA
C90-1551	90A-147E	Commission creates PSCo electric DSMCA - seven year amortization, $240/kW incentive.
C93-38	91A-480EG	Modified DSMCA incentive - $200/kilowatt base bounty depending on the cost of the individual DSM measure.
C95-1305	93I-199EG	Modified DSMCA - five year amortization and elimination of incentive payments.
R96-697	95A-625E	Commission approved WestPlains application to implement a DSMCA clause.
C05-049	04A-214E	DSM projects under Comanche settlement amortized over an 8-year period instead of previous 5 years.
	HB 07-1037	Legislature requires that electric DSM have an opportunity to be more profitable than other utility investments.
C08-560	07A-420E	Commission granted a new incentive mechanism for PSCo pursuant to HB 07-1037.
		Gas DSMCA
C92-1519	91A-783G	Established a gas DSMCA to recover low-income DSM costs allocated to gas customers.
	HB 07-1037	Legislature requires gas DSM incentive: lesser of 20% of net economic benefits or 25% of DSM program expenditures.
C08-248	07R-371G	Commission approved gas DSM rules implementing HB07-1037.

Section 4.6: Air quality improvement (electric)

Decision	*Docket*	*Summary*
R99-678	98A-511E	Settlement approved methodology for air quality improvement rider to recover PSCo air quality improvement costs.
C02-1422	02S-485E	Settlement to implement Air Quality Improvement Rider (AQIR) tariffs Rates became effective on January 1, 2003.

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Section 4.7: Renewable energy standard (electric)

Decision	*Docket*	*Summary*
C97-203	96A-401E	Approval of settlement establishing voluntary Windsource program. Wind Energy Service Adjustment tariff established.
C01-295	99A-549E	Commission ordered Public Service to acquire 162 MW of cost-effective wind energy from the Lamar project.
C05-412	04S-164E	Settlement modified Windsource rates, PSCo agreed to obtain Green-e certification for its Windsource program.
	HB07-1281	Legislation expands RES. Provides financial bonus based on 50% of the net economic benefits.
C05-1461	05R-112E	Adoption of rules implementing RES - utility can earn extra profit based on the net economic benefits.
C07-622	07R-166E	Adoption of rules implementing Renewable Energy Standard HB07-1281.

Section 4.8 Transmission costs (electricity)

Decision	*Docket*	*Summary*
	SB07-100	Legislation provides financial incentives for utilities to pursue the construction and expansion of transmission facilities.
C07-1085	07A-339E	Commission approved PSCo's initial Transmission Cost Adjustment.

Section 5.1 Natural gas price volatility management

Decision	*Docket*	*Summary*
C01-207	01R-083G	Emergency rules requiring utilities to consider measures to reduce customers' risk of gas price volatility.
C02-181	01R-346G	Permanent rules require consideration of measures to reduce customers' risk of gas price volatility, clarify cost recovery.
C04-1112	02A-267G	Monthly GCA settlement establishes gas price volatility mitigation as part of PSCo's regular gas procurement activities.

Section 5.2 Electricity price volatility management

Decision	*Docket*	*Summary*
C03-670	02S-315EG	Settlement requires PSCo to file an annual application for approval its gas hedging plan for electric generation.
C04-1281	04A-045EG	Commission approved settlement mitigating volatility of natural gas that PSCo uses for its electric generating facilities.

Section 5.3. Electricity trading

Decision	*Docket*	*Summary*
R00-830	99A-557E	Settlement authorized short-term trading . Positive aggregated net margins shared 50/50 in ECA, no losses to ratepayers.
C03-670	02S-315EG	Continued trading, modified sharing: Gen Book: 60% customers - 40% PSCo; Prop Book: 40% customers - 60% PSCo.
C04-1208	04A-050E	Trading docket. Trading continued, established business rules, audit plan, and reporting requirements.
C06-1379	06S-234EG	Modifies margin sharing. Gen Book: 80% customers - 20% PSCo; Prop Book: 20% customers - 80% PSCo.

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Section 6.1. HB07-1037 - DSM

Decision	*Docket*	*Summary*
	HB 07-1037	Legislation requires IOUs to reduce retail electric sales and capacity by 5% in 2018, based on 2006 sales.
C08-560	07A-420E	Commission approved electric DSM goals for PSCo which are higher than the minimum requirements of HB07-1037.
	HB 07-1037	Legislation requires IOUs to spend at least 0.5% of revenues from full service customers on gas DSM programs.
C08-248	07R-371G	Commission approved gas DSM rules implementing HB07-1037.

Section 6.2. HB07-1281Renewable resources

Decision	*Docket*	*Summary*
	HB07-1281	Legislation sets RES for IOUs at a minimum of 5% by 2008, 10% by 2011, 15% by 2015, and 20% by 2020.
C05-1461	05R-112E	Adoption of rules implementing the Amendment 37 Renewable Energy Standard.
C07-622	07R-166E	Adoption of rules implementing the HB07-1281 Renewable Energy Standard.
C08-559	07A-462E	Approval of Public Service's 2008 RES compliance plan.
R08-385	07A-356E	Administrative Law Judge approved a settlement agreement concerning Aquila's 2008 RES compliance plan.

Section 6.3. IGCC option

Decision	*Docket*	*Summary*
	HB06-1281	Legislation directs the PUC to consider voluntary proposals by Colorado electric utilities to build IGCC facilities.

Section 6.4. Natural gas partial decoupling

Decision	*Docket*	*Summary*
C93-38	91A-480EG	Commission directed parties to develop a decoupling mechanism for consideration in Phase I of 1993 PSCo rate case.
C95-1305	03I-199EG	Commission closed the investigation into decoupling.
C07-568	06S-656G	Commission approved a Partial Revenue Decoupling Adjustment pilot program for PSCo's residential gas customers.

Section 6.5. Treatment of CWIP

Decision	*Docket*	*Summary*
C05-049	04A-214E	PSCo received conditional current earnings on Comanche 3 CWIP, dependent upon bond rating.
	HB06-1281	Legislation provides for current earnings on CWIP for utility IGCC facility.
	SB07-100	Legislation grants current earnings on CWIP for utility transmission facilities.

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Section 7.1: Electric quality of service

Decision	*Docket*	*Summary*
		Public Service Company of Colorado
C96-1235	95A-531EG	PSCo - SPS Merger. Settlement established PSCo's first electric quality of service plan. QSP "rewards" deferred.
R97-767	97A-145E	Rewards Docket - Commission adopted a reward mechanism.
R98-10101	95A-531EG	Annual QSP docket. Eliminated QSP rewards for the years 1999 through 2001.
C00-393	99A-377EG	NCE - NSP merger. Settlement extended PSCo's QSP through 2006, increased the potential "bill credits."
R01-1034	00M-632EG	Changed the QSP benchmarks and exclusion process.
C04-1566	03I-134E	Investigation of transformer/cable problems. PSCo commits to spend $38 million over 3 years for feeder & cable repair.
C04-1566	04I-098E	Docket to hear PSCo consumer complaints of power outages during the summer of 2003.
C05-1438	05A-268E	Settlement modified QSP benchmarks - required an incremental $11 million PSCo investment to improve reliability.
C06-821	06I-118E	Investigation of PSCo February 18, 2006 controlled electricity outages
06-1303	05A-288E	Continued the PSCo QSP for the period 2007-2010. PSCo ordered to file a replacement QSP by January 2010.
		Aquila
R05-313	04A-046E	Settlement establishes QSP. Measures are customer complaints, telephone response, and electric service unavailability.

Section 7.2: Natural gas quality of service

Decision	*Docket*	*Summary*
C01-1330	99A-377EG	Established PSCo Gas QSP from 2002 to 2007. Adopted leak permanent repair and meter reading error measures.
06-1303	05A-288E	Continued the PSCo QSP for the period 2007-2010.