BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO
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IN THE MATTER OF THE INVESTIGATION	**)**	
OF REGULATORY AND RATE INCENTIVES	**)**	
FOR GAS AND ELECTRIC UTILITIES	**)**	**Docket No. 08I-113EG**

SECOND ROUND OF COMMENTS BY PUBLIC SERVICE COMPANY OF COLORADO

Public Service Company of Colorado ("Public Service" or "the Company") appreciates the opportunity to provide responses to the questions of the Colorado Public Utilities Commission ("Commission") in this proceeding. Before responding to the individual questions posed by the Commission in Decision No. C08-0903 (August 26, 2008), the Company will provide an Executive Summary of our responses, provide some background on the past and current regulatory framework in Colorado, and identify likely future challenges to the Commission and stakeholders.

I. EXECUTIVE SUMMARY

The Company welcomes this opportunity to begin a dialogue with the Commission and other stakeholders on the appropriate regulatory structure to address the energy future of Colorado. While this investigatory docket raises many important questions about utility incentives, we believe that it is important to design a regulatory model that will work to achieve the objectives of our Company, our customers, and the State of Colorado. As such, we believe it is important to identify the likely future for the electric utility industry in the nation and, more specifically, in Colorado. Once this likely future is defined, the relative costs and benefits of any new regulatory structure can be better assessed. Public Service will provide our view of the future and the resulting cornerstones of a regulatory model that will be necessary to support this future. In many ways, the issues currently facing Colorado are applicable to utilities nationwide. Looking forward, we believe that utilities are currently planning for, and will be required to make, much more significant, some would say even massive, capital investments in their systems to meet a variety of both new and traditional needs. The following factors will also increase both the cost structure of the utilities and the rates paid by utility customers:

- Utilities in the future will be called upon to change both the resources they currently rely on and the types of resources they add to make them cleaner and less carbon-intensive. The costs of these new technologies are likely to be more expensive than the costs of technologies that do not address these environmental concerns to the same degree.
- The heavier emphasis on renewable resources to meet future energy demands will require significant transmission investments to bring these resources to market.
- The United States' utility infrastructure is old and will need to be replaced or upgraded. The quality of electric service is likely to be enhanced and its corresponding cost higher, as technology that incorporates what is now regularly referred to as "SmartGrid" begins to be more widely deployed.

- The resources used by utility systems have been and will probably continue to be characterized by rising, rather than declining, incremental costs.
- All of the above trends will heighten both the need for, and cost-effectiveness of, energy efficiency.

The Company believes that the vertically-integrated utility model in states such as Colorado that have not gone through restructuring will continue for the foreseeable future. If this assessment is accurate, then the Commission will continue to need to determine whether utility-proposed construction of generation and transmission projects is in the public interest. To the extent stakeholder interests are aligned, as we believe is the case, then the regulatory model should facilitate raising the capital needed to move the State of Colorado forward to meet the objectives of the New Energy Economy, as well as the more traditional goals of providing reliable and high-quality service at just and reasonable rates.

To facilitate needed investment in utility facilities, it is important that any changes to the current regulatory model strive to accomplish three goals:

- <u>There needs to be timely recovery of investment costs.</u> Regulatory lag will not allow utilities to gain the confidence of financial markets needed to fund the billions of dollars of necessary new investment. Lags in the cost recovery of significant new investments that are well above the level of depreciation will erode utility earnings. This is one reason why some jurisdictions have used investment riders, project-specific cost-recovery mechanisms, and/or formula rates to minimize this lag so that investments can be made.

- Commissions should provide more certainty that the utility will be able to recover investment costs. No utility would proceed with (for example) a new nuclear plant in today's market without some high level of assurance that the investment is desired by the state and that its costs will, in spite of the construction cost risks, be allowed recovery in rates. The same is true for other large capital projects. Major projects need up-front Commission approval so that the *decision to undertake the project* is not challenged later. The ongoing review of management prudence in implementing the approved projects at a reasonable cost remains an appropriate part of the regulatory framework. Thus, substantial regulatory risk remains, particularly in a rising-cost environment.
- Commission support for a reasonable return on equity that will attract the attention and support of investors is crucial. Many observers believe that if utilities are allowed to reduce the lag and uncertainty of cost recovery, then the risk of financing major capital projects is significantly reduced and the authorized return on equity should be correspondingly adjusted. This linkage may at first blush appear reasonable, but it is important to remember that the measurement of ROE is always guided by a comparison of the risks faced by the regulated utility with the business and financial risks faced by other, comparable utilities. If these same risks are reduced elsewhere with no corresponding reduction in the measured ROE, it is likely because financial markets have assumed a higher risk of full cost recovery even under a well-structured regulatory environment. This response is actually quite rational, as

the absolute dollars needed to be recovered through the regulatory process will increase at a faster rate than in the past, as will customer rates. As such, the overall required return will probably remain constant or even rise, in order for the utility to attract capital even in a “reduced lag” regulatory environment.

While these three objectives will be critical to meeting the capital requirements of the future, any regulatory model must continue to address the more traditional concerns of regulation, including the reliability of the grid and the efficiency of utility operations. Achieving these goals forms the foundation of the overall regulatory structure. To date, the current model’s reliance on regulatory lag, given the size of investments and the long investment horizons that utilities face, will pose a challenge. But the Company stresses that regulatory lag is not the only way to encourage efficient operations. Nor may it necessarily be the most important objective in light of the state’s policy construct. For example, it may be preferable to incent construction of significantly higher levels of transmission investment, in order to assure the timely implementation of renewable objectives, than to assure that the utility achieves some defined level of efficiency in construction or operations. While we will continue to strive to achieve these goals, we will likely face much higher rates of change in the real cost of energy than we have experienced during the last two decades. The regulatory construct should recognize the challenges this presents.

As the Commission looks at the regulatory “State of the Art” across the country, we believe it will discover that many jurisdictions, particularly where utilities have embarked on major investment programs or projects, have revised their traditional utility regulation. We believe this review is important, as at least three fundamental changes have influenced recent reforms.

First, there is greater recognition of the natural and strong alignment between utility and customer interests. For example, both utilities and customers want a strong, reliable grid with sufficient generation resources to meet the State's public-policy goals. Thus, for example, certainty of cost recovery over the life of a major project to allow for this investment to occur is one way in which regulation has adapted.

Second, financial markets are clearly driving the need to change the regulatory structure. Investment capital is a scarce resource – as has been dramatically highlighted over the past few weeks; there is a real cost to attracting capital. As we enter a period of increasing investments in an escalating price environment, access to this capital will not come easily, or on the same terms available in the recent past. In the late 1970s and early 1980s, when the utility sector faced a similar period of higher-than-normal levels of inflation and large investment programs, many utilities faced significant cost-recovery problems. Investors remember this experience, and utilities have worked with commissions to address these concerns.

Third, we believe that the Commission should carefully consider the merits of rate riders independently. Each was created for a specific purpose. The actual number of riders is, from our perspective, less important than whether a given rider benefits the State and our customers. Some riders respond to the inability of traditional ratemaking to encourage the full pursuit of all cost-effective initiatives if the costs are capped by a test-year budget. Others riders attempt to manage the volatility in commodity or fuel costs both for the Company and customers. Other riders are designed to facilitate investments. As the Commission evaluates other models, it should consider whether these models can achieve the same goals that the current riders achieve.

The Company does not propose a single plan or structure. We do not believe that there is a single right way to achieve common objectives. Rather, we hope that these comments will provide an opportunity for further dialogue about how the Company, the Commission, our customers, and other interested stakeholders can work collaboratively to achieve a regulatory structure that advances the interests of all. We recognize that some of the alternatives we discuss may require statutory changes. But we believe the exploration of alternatives in this investigation should include all reasonable policy options.

II. BACKGROUND ON CURRENT REGULATORY STRUCTURE

Dr. Schmitz summarized the history of gas and electric ratemaking in Colorado in his *History of Colorado Energy Industry Regulatory Incentives*, a report prepared and issued as part of this proceeding. The Company will not revisit all of this history, but simply reiterate a few important conclusions.

For many years the Commission has set base rates for utility services using the costs and revenues of representative, historical test years. The pronounced regulatory lag created by the use of historical test years, coupled with the lag between the filing of a rate case and the Commission's approval of new rates, may offer some advantages. But any such advantages are outweighed by significant disadvantages.

The assumed advantage of regulatory lag is that it provides a financial incentive for utilities to manage costs and revenues not only between rate cases, but also during rate-case proceedings and immediately afterwards. In other words, there is a continual incentive for utilities to manage earnings, since the utility cannot immediately capture cost increases or revenue losses through rates. But Public Service believes that this assumed advantage is questionable. Regardless, it is outweighed by the disadvantages of setting rates based upon past history instead of the expected future environment. Public Service believes it is time to implement all ratemaking decisions on a forward-looking basis. Here is why we believe that this shift is important.

First, long lags do not allow utilities to pursue large capital investments without significant earnings drain. A well-regulated utility should be able to bring substantial capital investment to Colorado to facilitate the shift to the New Energy Economy. It is counterproductive to hamstring such an important source of funds by artificially impairing the achievement of acceptable earnings. Second, some costs (such as fuel costs or the costs of public-benefits programs) can fluctuate significantly on an annual or even a monthly basis. Rates adjusted only through general rate cases cannot capture these changes, meaning that the utility either under-recovers or over-recovers these costs. Just as important, rates that do not capture these cost fluctuations in a reasonable and timely manner lead to subsidies among customer classes or among customers in the same class.

Third, continual increases in the costs of inputs used to provide utility services (labor, materials, etc.) bias the utility's likely earnings to levels below authorized returns even without the purposeful infusion of regulatory lag. If the inflation rate is 4 percent, costs incurred in 2006 will be a little over 8 percent higher in 2008. This means that rates implemented in 2008 based on a historical test year of 2006 will not be compensatory in 2008. While productivity improvements, growth in use per customer and/or hot or cold weather may offset inflation to some degree, over time there will be a bias towards under-collection.

This phenomenon is borne out by Public Service's returns on equity from 2000 through 2007 for its gas and electric utilities. During that period the Company's electric utility earned more than its authorized return only once, in the year 2000; we earned less than our authorized return during the other seven years. The average annual authorized return during that period was 10.81 percent, while the average annual earned return was 9.48 percent.

Public Service's gas utility earned more than our authorized return for three years, and less than our authorized return for five years. The average annual authorized return during that period was 10.88 percent, while the average annual earned return was 9.98 percent.

Fourth, high-quality service requires continual system upgrades and sufficient qualified personnel to respond to customers' needs. Such initiatives increase over time both capital and O&M expenditures. It is counterproductive to service quality to artificially constrain the utility's ability to handle these cost increases.

Some of the shortcomings inherent in setting rates based upon historical test years have been addressed by the introduction of adjustment clauses. We discuss the purposes of a few of these clauses next.

Public Service has had fuel adjustment clauses for decades, because the Commission has recognized that these fuel expenses are large, volatile, and largely beyond the control of Public Service. Recently, the Company and the Commission became concerned that the volatility in natural gas prices, in particular from month to month and season to season, required changes to the Company's fuel adjustment clauses on bases more frequent than annually. This modification allows the Company to avoid large deferred balances in the adjustment clause accounts, more accurately recover costs from the customers who impose these costs, and provide more accurate price signals to customers. These clauses were made forward-looking, again to recover costs more accurately and send better price signals. Without the GCA and ECA, the Company would be forced to file multiple rate case simply to reflect its rapidly changing fuel costs.

The gas and electric Demand Side Management Cost Adjustments ("DSMCA") recognize the unique challenges associated with utility-sponsored DSM programs. As discussed in more detail in our response to Question 6, there are multiple reasons for the DSMCAs, stemming from the utility's financial disincentive to implement effective DSM programs and the fact that the costs are significant and change significantly from year to year.

The Purchased Capacity Cost Adjustment ("PCCA") is an important vehicle for allowing the Company to reduce the level of rating agencies' imputation of debt-equivalent obligations from the stream of capacity payments required under the Company's various purchased power agreements ("PPAs"). As the Company has discussed in many cases before this Commission, the PCCA reduces the risk factor assigned by Standard & Poor's in the calculation of PPA imputed debt. In this respect the PCCA serves a unique purpose. The PCCA also serves a traditional purpose of adjustment clauses – to reflect changes in significant cost components in a more timely manner.

The Renewable Energy Standard Adjustment ("RESA") was developed to track the incremental cost of renewable energy acquired by Public Service so that compliance with the retail rate impact limitations in Amendment 37, now C.R.S. §40-2-124 (g)(I), could be determined. To encourage acquisitions of renewable resources (including acquisitions above and beyond the minimum levels needed to comply with the Renewable Energy Standard), the Commission's Renewable Energy Standard Rules specifically provide for timely cost recovery of these favored expenditures through forward-looking adjustment clauses. See Rule 3660.

Public Service currently recovers the costs of renewable energy acquisitions acquired after the passage of Amendment 37 (with four Commission-approved exceptions) through a combination of the RESA and the ECA. The RESA recovers the incremental costs of these renewable resources (limited to 2% over the cost of the avoided non-renewable resources), and the ECA recovers all costs of the renewable resources up to the costs of the avoided non-renewable resources. Timely cost-recovery mechanisms can be used to allow utilities to meet and exceed important public-policy objectives.

The Transmission Cost Adjustment ("TCA") and Air Quality Improvement Rider ("AQIR") are "investment riders," in that their primary purpose is to reduce or eliminate the lag between the incurrence of costs for important infrastructure or environmental investments and the recovery of these costs. These riders also more accurately charge customers for the specific facilities used to provide them services. As noted at the outset, the need for timely recovery of investment costs is an important objective. As we discuss below, this objective can be achieved either through the use of rate riders or more comprehensively through enhancements to the current regulatory model --or a combination of both strategies.

The electric Quality of Service Plan ("QSP") provides the utility with a financial incentive, through penalties, to offer high-quality service.

In short, the current ratemaking framework is arguably the end result of warranted efforts on the part of the Colorado General Assembly and the Commission to achieve important public-policy goals. The reliance on historical test years was originally implemented to provide the utility with an incentive to operate efficiently and reduce costs. The periodic authorization of adjustment clauses and other departures from traditional cost-of-service regulation were layered on top of this basic framework in response to the concerns summarized above. The end result is arguably a proliferation of adjustment clauses, quality-of-service plans, incentive mechanisms and prudence reviews. This complexity may raise concerns; but any changes to the existing regulatory structure must recognize and address the original public-interest reasons for the status quo. Some of these reasons may no longer be relevant, but we believe most still are.

II. RECENT AND FUTURE CHALLENGES

OVERVIEW

The ratemaking alternatives that the Commission is exploring in this proceeding should be informed not only by the regulatory history to date, but also by recent trends and anticipated challenges over the next few years. Below the Company identifies trends over the past several years that may continue into the future and explores their implications for alternative ratemaking approaches and utility incentives.

INCREASING MARGINAL COSTS

One recent trend is higher costs for the Company's labor, materials and plant. Strong international demand for resources, fueled by growth in China, India and other developing countries, will increase input costs faster than would otherwise be the case. Structural issues in the U.S. budget are also likely to cause upward pressure on input costs. It is difficult to predict how the dramatic events of the past week will affect this view. But over time, and absent a radical economic setback, these issues will likely continue to persist and drive prices higher over the long run.

The annual percentage increases in the costs of key inputs in the Plateau Region (which includes Colorado), based on the most recent data from *Global Insights*, is provided below:

YEAR	STEAM PROD. PLANT % INCREASE	GAS TORBOGEN. PROD. PLANT % INCREASE	DISTRIBUTION PLANT % INCREASE
2007	5.2	16.5	11.2
2008	7.6	12.5	11.9
2009	3.7	5.2	3.6

The comparable percentage increases in the Company's Corporate Escalation Factor for 2007, 2008 and 2009 are 3.6 percent, 6.56 percent and 3.24 percent, respectively.

As explained above, the equity and efficacy of regulatory lag are at best questionable during periods of increasing marginal cost, when productivity improvements cannot realistically be expected to offset increases in input prices. Further, higher levels of capital investment, produce a similar bias. During such periods a reliance on traditional rate cases with historical test years and delay in rate implementation can lead to systemic under-earnings and higher costs of raising capital. These higher costs of raising capital are ultimately passed on to customers.

INCREASING CAPITAL EXPENDITURES

The industry as a whole has experienced a sharp increase in capital expenditures over the past two years. The reasons for this increased capital spending include the need for additional baseload generation, the need for transmission and distribution upgrades, and the increasing costs of environmental compliance.

Utilities are currently discussing extra-high voltage lines costing billions of dollars to move energy from clean generation resources to regions of the country that do not currently have access to renewable resources. In the West, where renewable resources are more abundant, large regional lines are needed to help cost-effectively move power from more remote locations to multiple markets.

Utilities have been able to prolong the useful lives of equipment and facilities. But these assets must ultimately be replaced at a much higher cost. The result will be increases in the utility's cost of service.

In the spring of 2007 the Edison Electric Institute ("EEI") completed a study of industry capital spending. This study concluded that actual capital expenditures in the electric industry have increased significantly over the past three years and are expected to continue increasing in 2008 and 2009. The actual and estimated capital expenditures provided by EEI are listed below:

YEAR	CAPITAL EXPENDITURES (U.S. Shareholder Utilities)
2004	$41.1 Billion (Actual)
2005	$48.4 Billion (Actual)
2006	$59.9 Billion (Actual)
2007	$69.1 Billion (Actual)
2008	$75.0 Billion (Projected)
2009	$75.5 Billion (Projected)

Public Service's projected capital expenditures are consistent with this industry trend. The Company's five-year capital budget reflects continued high levels of spending that are expected to exceed the Company's internally generated funds and require additional borrowing and equity investment. The Company believes these investments will benefit customers by assuring that we continue to provide reliable, high-quality service.

This higher level of investment will place pressure on utilities to issue additional debt and equity. Utilities can manage their financing costs to reasonable levels only if the capital markets anticipate timely and complete recovery of all prudently incurred investments.

Substituting purchased power for utility-owned generation may reduce a utility's capital requirements, but there is a growing awareness that such purchases often increase the utility's financial risk and result in higher debt and equity costs. Generally, PPAs that represent large capital investment by an Independent Power Producer can (absent an alternative mechanism such as the PPCA) also cause significant harm if regulatory lag is not reduced. Public Service explained to the Commission in Docket No. 07A-447E our views of the problems created by an over-reliance on purchased power in our generation portfolio and the attendant concerns of imputed debt, capital lease accounting, and consolidation for financial reporting purposes.

LUMPY INVESTMENTS

The electric industry in particular is characterized by the need to undertake very large, discrete investments. The salient example is baseload generating plants, such as the Company's Comanche 3 generating unit, which must be of sufficient scale to capitalize on the economies of scale in generation capacity and lower long-term costs to customers. As noted above, additional baseload plants account for a significant percentage of the rising capital expenditures in the industry. Timely recovery of these investments is crucial to eliminate the financial disincentives of regulatory lag and to lower the financing costs ultimately borne by customers. Similar large, lumpy investments are anticipated going forward as we pursue additional transmission plans consistent with our SB 100 obligations and as we replace carbon-emitting resources with cleaner alternatives.

INCREASED EMPHASIS ON RECOGNIZING THE SOCIETAL IMPACTS OF PRODUCING ENERGY

Over the past several years the State of Colorado has begun the transition to a "New Energy Economy" that features an increased reliance on renewable energy, energy efficiency, more sophisticated pricing, and better protection of the customers least able to afford service. Achieving these worthy goals requires a transformation of the utility mission. In the past utilities were required to meet all applicable governmental health, safety and environmental standards. The costs of such compliance were included in the utility's revenue requirements. Within the constraint of complying with all governmental standards, the utility's mission was then to minimize its cost of service.

But this traditional goal of providing reliable utility service at least cost to customers has been modified. Colorado utilities must now emphasize the consequences of their decisions on environmental quality, price risk and affordability. This shift in focus often leads to programs or resource decisions that may raise utility rates in the short term, but are designed to:

- reduce environmental impacts,
- reduce the risk of fuel-price increases,
- allow customers to receive the same level of service with less energy use,
- send better price signals, and/or
- ease the burden on low-income customers.

In effect, utilities are being asked to provide energy services considering factors other than the provision of electricity and natural gas at the absolute lowest private cost. This new mission in no way requires or even anticipates the consideration or quantification of all potential societal impacts of various alternatives for providing energy services. But the State is placing a relatively greater emphasis on these societal goals than it did in the past.

For example, neither the non-energy benefits of DSM programs nor their costs to participating customers are part of a utility's revenue requirements. Yet when evaluating the cost-effectiveness of DSM programs, the utility is required to employ a Total Resource Cost test that includes both impacts. Colorado's renewable energy standard is another example of an initiative that raises revenue requirements in return for other public-policy benefits. Moreover, the Colorado General Assembly recently authorized utilities to expand upon our offerings of low-income programs.

This shift in focus requires innovative regulatory mechanisms to ensure that the utility's financial interests are aligned with the State's public-policy goals and that customers receive the full benefits of the public-policy direction provided by the General Assembly and Commission.

FUEL PRICE VOLATILITY

Fuel prices, particularly the price of natural gas, have demonstrated increasing volatility. For example, the Company's GCA for residential customers decreased from $1.0187 per therm in August 2008 to $0.4992 per therm in September 2008. In other words, the price declined by about 50 percent in one month. Similar but less pronounced price volatility has occurred in previous years. This volatility affects both natural-gas and electric services, and there is little indication that prices will be more stable in the future. While the Company can hedge its fuel costs to reduce the price risk to customers, these hedging efforts entail their own costs that are ultimately passed on to customers.

DECLINING USE PER CUSTOMER

The natural gas industry has experienced declining use per customer for at least two decades. From July 2000 through June 2006 the average use of the Company's residential gas customers declined by about 2.6 percent annually. While electric use per customer has not yet declined, utility DSM programs, distributed generation, the natural penetration of more efficient appliances and higher electric prices will tend to reduce usage and slow the rate of growth over time. Since the Company recovers a large share of its costs through usage or demand charges, reductions in customer use tend to erode earnings between rate cases and ultimately lead to higher prices.

SUMMARY OF FUTURE CHALLENGES

During much of the 1970s and 1980s the utility industry was characterized by high inflation and significant plant additions to meet projected growth. In contrast, most of the 1990s was characterized by relatively stable prices for utility services. Many utilities were reducing O&M and capital spending in anticipation of competition in the market for retail generation services. Other utilities were focusing on reducing reserve margins and reducing utility-sponsored public-benefits programs for the same reason.

The general rate of inflation was very low, and fuel prices (in retrospect) were relatively low and stable. Under these conditions, traditional ratemaking was reasonably effective.

The situation now is more similar to that in the 1970s and 1980s. Few states are interested in restructuring to create competitive markets for retail generation services. Utilities and customers are trying to manage cost increases due to increasing labor and material costs, volatile commodity markets and high levels of capital expenditures. At the same time, the public is demanding more emphasis on environmental protection and relief to customers least able to afford utility services. The widespread deployment of public-benefits programs in response to these demands further raises costs.

But while it is important to recognize such challenges, it is equally important to recognize some very promising developments. Energy-efficiency programs will ultimately lower costs to customers, while low-income programs should mitigate the bill impacts for those customers least able to afford basic utility services. The investments in renewable technologies may be more costly now, but will provide a hedge against natural gas price increases, significantly reduce air emissions, and position Colorado to capitalize on the continual improvements in renewable technologies. The Company's recently approved retirement of four coal-fired generating units will also reduce air emissions, as will the explicit valuation of carbon emissions in the Company's resource planning. Investments in innovative technologies such as SmartGrid will ultimately allow customers more options for controlling their bills and reducing the environmental impacts of their energy use.

Finally, when considering the impacts of various ratemaking alternatives on utility incentives, it is also important to remember that a utility's financial interests can be and should be aligned with public interest goals. There are ways to reward utilities for effectively implementing DSM programs and encouraging distributed generation. There are ways to reduce regulatory lag while maintaining the utility's incentive to operate efficiently – with or without some adjustment clauses. There are broad initiatives that utilities can undertake broad initiatives that both enjoy broad public support and reduce long-run costs (even if they raise short-run costs). While goals and interests sometimes compete, there is considerable common ground. When responding to the Commission's questions regarding utility incentives, the Company will focus on identifying that convergence.

IV. RESPONSES TO COMMISSION'S QUESTIONS

1. The NRRI paper identifies six possible commission goals:

- ***ensure adequate physical infrastructure,***
- ***ensure cost-effective demand-side management and energy efficiency,***
- ***respond to climate change,***
- ***induce cost-effective management practices,***
- ***maintain excellent service quality, and***
- ***spur technological innovation***

Each of these goals presupposes that rates are set at just and reasonable levels.

We invite comment on this list of goals; whether any items should be added or deleted from this list. What are the relative priorities of these goals? Are the suggested goals compatible? Explain how any tradeoffs between the goals can be reconciled.

When articulating public-interest goals it is easy to supplant broad, over-arching goals with vehicles or means of achieving these goals. Public Service believes that a high-level list of commission goals should reflect the end results that the public desires. These end results would seem to be: strong levels of reliability and service quality; minimizing the long-run societal costs of utility-provided energy services, stabilizing customer bills for energy services, recovering costs from customers equitably, and providing customers with multiple service options. The net costs would include both the utility and customer's private or internal costs of providing energy services, as well as various additional costs and benefits accruing to society that would primarily be considered on a qualitative basis. These basic public-interest goals should be clearly distinguished from their components or subparts, as well as from the vehicles through which the goals can be achieved. For example, the maintenance of an adequate physical infrastructure could be viewed as a subset of the goal of maintaining high-quality service. The promotion of cost-effective DSM and responses to climate change could be construed as vehicles for achieving the broader goal of minimizing the long-run costs of energy services. Likewise, technological innovation could be viewed as a vehicle for attaining all of the primary public interest goals. These vehicles should not be treated as goals in themselves, but rather as ways to best meet the true public interest goals.

Based on this reasoning, the Company suggests the following goals:

- Maintaining strong reliability and service quality.
- Minimizing the long-run cost of energy, with the potential consideration of other societal impacts.
- Stabilizing prices.
- Equitably recovering costs from the appropriate groups of customer.
- Providing service options to customers.

There are a wide variety of *vehicles* for achieving these goals, including but not limited to, DSM, renewable resources, hedging plans, a robust utility infrastructure, a financially sound utility, utility financial incentives to operate efficiently and reliably, and technological innovation. For example, the second goal listed above captures the goals listed in the NRRI report of encouraging DSM and preparing for climate change.

Of particular importance to this investigation are the assurance of the utility's financial health and the aligning of utility incentives with public-interest goals. (In contrast, the goal of providing service options is probably less of an issue for this investigation.) While a financially healthy utility may not be a high-level, public-interest goal in and of itself, it is an absolutely critical condition for meeting the goals listed above. The utility's financial health is an issue of importance not only to shareholders, but also to customers. A utility with little opportunity to earn its authorized return will face higher financing costs – both for equity and debt. It will not be capable of making discretionary investments that create long-run benefits. Moreover, utilities with poor financial prospects will find it difficult to raise the capital required for critical infrastructure improvements that improve service quality. These higher costs will ultimately be borne by customers, thereby increasing the net long-run cost of providing utility services and impairing the achievement of the first two public-interest goals.

Similarly, as explained throughout these comments, the aligning of utility incentives with public-policy goals is necessary to best achieve the high-level public-interest goals.

The five goals listed above often do conflict with one another and need to be reconciled. The challenge is that it is difficult to quantify “success" in achieving these goals. The most direct way to balance goals is to place dollar values on them (monetize them) to allow for direct comparisons. But improvements in environmental quality, national security, and other policy goals are difficult to quantify. It is likewise very difficult to monetize additional price stability or customer choice. Service quality can be assessed through many performance metrics. But it is difficult to monetize any given improvement or deterioration in service quality or the equitable collection of costs from customers – to evaluate whether a given improvement in one area justifies the cost of achieving the improvement. As a result, the optimal balancing of goals will always require judgment and qualitative assessments. The Company believes that providing strong levels of service quality and minimizing long-run costs (all while maintaining the financial health of the utility) are the most important of the five goals, followed by price stability, the equitable collection of costs from customers and customer choice.

2. ***Please discuss how the Commission's current regulatory regime, as applied to electric and gas utilities, promotes or impedes achievement of the policy goals identified by your response to Question 1.***

The Commission's current regulatory regime does promote the achievement of these public-interest goals, but could be improved. An assessment by goal is provided below:

STRONG RELIABILITY AND SERVICE QUALITY

Utilities have traditionally been required to maintain strong reliability and service quality through a variety of standards and requirements. For example, the Company is required to maintain adequate planning and reserve margins to ensure reliable electric service. The types and timing of resources for best meeting these requirements are developed in resource-planning proceedings. Moreover, the Commission has established quality-of-service standards under the Company's Quality Service Plan ("QSP") and assessed penalties for performance that falls short of these standards. The Company notes that service-quality plans that provide only a "stick" and not a "carrot' are generally less effective than plans that provide both. (See response to Question 8.)

But regulatory lag works against the goal of strong reliability and service quality. Utilities contemplating large investments to enhance reliability and service quality are not allowed to recover the costs of these investments through utility rates until they are captured in a historical test year and the Commission approves final rates. That lag is a significant financial disincentive to being proactive in improving reliability and service quality. The Company believes the utility should not have to choose between earning its authorized return and providing high-quality service. The reduction in regulatory lag could help resolve this conflict.

MINIMIZATION OF LONG RUN SOCIETAL COSTS

When discussing the minimization of long-run costs, with the potential consideration of other societal impacts, the Company will address separately recent regulatory initiatives to advance public-policy goals, the impact of regulatory lag on cost minimization, the impact of riders on cost minimization, and the impact of fuel-cost recovery on cost minimization. The long-run element is critical, as many of the investments that the utility industry is facing will cause short-run price increases but have the potential for long-run benefits. This is another way of suggesting that costs should be "optimized" rather than simply minimized. The goal of minimizing costs can lead to short-run decisions to cut costs and defer investments. Such decisions may not appropriately capture the potential benefits of such investments in terms of quality of service or reducing future economic costs.

The General Assembly and the Commission have recently taken steps to introduce broad environmental and other public-policy goals into a utility's resource decisions. The focus has shifted from solely minimizing the private costs of traditional utility commodity and delivery services to an evaluation that considers other impacts as well. For example, the approval of DSM savings goals and benefit-cost tests advance this goal, as does the implementation of the renewable energy standard.

As was discussed in connection with Public Service's 2007 Electric Resource Plan in Docket No. 07A-447E, many of the policy objectives that are set forth in recent statutory enactments are difficult or impossible to quantify and need to be addressed on a qualitative basis only. Judgment must be employed to weigh the respective impacts of various resource alternatives on environmental improvement, price stability, energy self-sufficiency and economic development.

As we discussed earlier, the use of historical test years creates significant "regulatory lag." One of the reasons advanced for this approach is that it provides utilities with an incentive to reduce the internal or private costs of providing energy services. On the other hand, utilities would have this same financial incentive if the implementation of new rates coincided with the test year (i.e., if there were no regulatory lag). Whatever "bogey" is established in terms of rates and cost recovery, the utility can almost always increase its earnings over time by reducing costs. Because cost-containment initiatives are not capable of starting and stopping with a decision to file a rate case, utility cost-containment measures will be reflected in rates in a forecast test year as well as a historic test year. The duration of the regulatory lag affects primarily the allocation of risks and rewards between customers and shareholders and the utility's incentive to invest in its bulk-power and delivery systems.

We believe that regulatory lag is counterproductive: It does not allow the State to achieve the higher levels of utility investment that are likely to be required; it does not reflect the costs incurred by the utility and, in most cases, fails to provide the utility an adequate opportunity to earn its authorized return; it is not an effective tool when the public policy of the State is fostering goals that run counter to pure internal cost minimization. Colorado lawmakers have passed laws encouraging utility investment in the New Energy Economy – such as investments in generation, transmission and energy efficiency. It is counterproductive to maintain a regulatory structure that "fights against" this public-policy goal by making it harder or more expensive for utilities to raise and spend capital that garners acceptable returns.

To counteract the regulatory lag from historical test-year ratemaking and the lack of any form of timely rate implementation such as interim rates, the Commission and the General Assembly have employed a number of rate riders or adjustment clauses. These mechanisms are useful for limiting a utility's exposure to the risk of cost fluctuations over which it has little control – such as fuel costs. Riders are also important for encouraging significant capital investment, particularly when sales growth is not growing at an extraordinary pace. In Colorado, riders have been successfully employed to encourage utility investment in voluntary emission controls beyond the level required by law, DSM programs, renewable resources, and transmission infrastructure.

Riders have long been deemed essential for the recovery of volatile fuel costs. Utilities are largely "price-takers" for natural-gas commodity services. While the Company can take steps to minimize the costs of purchasing natural gas, prices in that commodity market are primarily a function of national (or even international) supply and demand. The Commission has relied on traditional prudence reviews to encourage cost-effective commodity purchases to meet the needs of natural-gas sales customers. The Company believes these prudence reviews induce the Company to lower fuel costs, although the lack of any positive incentive skews the allocation of risks and rewards.

Many of the same observations relevant to natural gas also apply to electric fuel costs. One important difference is that the Commission has provided a financial incentive for the Company to reduce its electric fuel costs through the incentive component of the Company's ECA. The ECA incentive currently seeks to minimize fuel costs by increasing the availability of the Company's coal plants and by encouraging off-system purchases. The Commission has indicated that it wishes to revisit these specific incentives in Public Service's next rate case, now that the public-policy emphasis has shifted from cost minimization to carbon reduction. The Company agrees that the ECA incentives should be aligned with public-policy goals and we will propose in our next rate case new incentive proposals that provide that alignment.

PRICE STABILITY

Price stability is particularly crucial for natural-gas customers, as commodity services account for about 75 percent of a customer's bill and the prices of these services vary widely on a monthly and annual basis. The Company relies on a combination of physical and financial hedges to mitigate the impact of price changes on customers. The Commission approves this hedging plan on an annual basis. The Company believes that these plans have stabilized prices. However, stability always entails a cost. The Company could theoretically lock-in prices for 100 percent of its commodity purchases. But the price of this "insurance" would be prohibitively expensive. Consequently, the Commission must decide on the proper balance between price stability and cost minimization.

Similarly, for electric service the Commission also allows utilities to hedge against fluctuations in fuel costs. With the caveats explained above, the Company believes this is an effective approach. Moreover, the increased reliance on wind and solar generation provides another hedge against increases in fuel prices. Overall, the Company believes the Company and the Commission have been reasonably successful in promoting price stability.

EQUITABLE RECOVERY OF COSTS FROM CUSTOMERS

At least two criteria can be used to assess whether the costs of utility service are being collected equitably. First, costs incurred to provide service to customers in one year should, to the extent possible, not be recovered from customers in another year. Second, rates should be designed, to the extent possible, to limit subsidies between businesses and residential customers, between small and large customers, or among customers with varying load factors or usage profiles. This criterion is usually captured in the traditional ratemaking goal of basing rates on the cost of providing service.

Another goal may be to reduce the burden on low-income customers through rate or other incentives financed by other customers. This approach would require a subsidy, or a departure from cost-based rates, but the subsidy would be targeted so as to (arguably) achieve a more equitable collection of costs.

CUSTOMER CHOICE

Customers would ideally be able to choose from multiple tariffs that reflect trade-offs between the expected price and other objectives, such as bill stability or the support of renewable resources and DSM programs. The attainment of this goal has historically been hampered by the metering and administrative costs of more sophisticated pricing options and uncertainty about the net benefits of such options. Public Service is currently exploring ways to overcome these barriers, primarily through its *SmartGridCity* demonstration project.

The Commission's current regulatory regime probably tends to discourage customer choice. The emphasis on regulatory lag is an impediment to new service offerings. The Company believes that forward-looking pricing and more timely cost recovery, with adequate protections against revenue erosion for significantly different forms of pricing initiatives where customer response is at best uncertain, would better align the utility's interests with the public-policy goal of promoting customer choice.

Moreover, due to the pace of the policy changes to date, Commission and stakeholder resources have been focused on how best to encourage certain types of specific resources, such as renewables and DSM. There has been less emphasis on more market-oriented approaches to achieving efficiency gains -- such as sending better pricing signals to customers -- that require new tariffs. This second impediment to customer choice is more of a practical problem than a structural problem with the current regulatory regime.

3. Please discuss the manner in which each of the following features of cost of service regulation affects the incentives of a utility:

a. ***Allowed earnings calculated as authorized rate of return times rate base***

b. ***Use of net original cost rate base***

c. ***Regulatory lag (base rates persist until changed after rate case or complaint case)***

d. ***Choice of test period for a rate case***

e. ***Timing of rate cases***

f. ***Current earnings on construction work in progress***

g. ***Prices based on historic cost***

<u>Allowed earnings calculated as authorized rate of return times rate base</u>

The impact of this approach to setting earnings depends on the level of the authorized return and the regulatory lag. If the return on investment (adjusted for the impact of regulatory lag) is set at the utility's opportunity cost of attracting capital in the market, then the utility is theoretically indifferent to undertaking new investments. Because they are disciplined by capital markets, utilities will seek to invest in "safer" investments to the extent expected returns do not vary. Utilities can be encouraged to invest in accordance with public-policy goals through higher returns for such investments or accelerated cost recovery. In other words, setting allowed earnings based on a return applied to rate base might provide either an incentive *or* disincentive to new investment, depending on other aspects of the regulatory regime.

Use of net original cost rate base

The impact on utility incentives of using the net original cost rate base for ratemaking purposes is relatively minor, in that it does not skew investment decisions either way. But this feature of traditional regulation may affect the utility's incentive to sell or purchase a regulated asset, depending on whether the market value of the asset is greater or less than its original cost minus accumulated depreciation and the Commission's policy on acquisition adjustments.

Regulatory lag

Regulatory lag usually reduces the utility's earned rate of return and provides a disincentive to new investment.

Choice of test period for rate case

A projected or forecasted test year allows the utility a better opportunity to achieve its required rate of return than a historical test year. Either test year provides the utility with an incentive to operate efficiently and reduce costs. A projected test year also enhances a utility's ability to raise capital at attractive rates, thereby lowering rates to customers. Finally, a forecasted test year reduces, but does not eliminate, the earnings erosion attributable to DSM programs and distributed generation.

Timing of rate cases

In most case, more frequent rate cases provide the utility with a greater opportunity to realize its authorized rate of return. Some states, such as Wisconsin, have established a predetermined schedule for rate-case filings. This approach provides certainty to regulators that there will be periodic reviews of the utility's earnings and activities.

Current earning on construction work in progress

Current earnings on construction work in progress ("CWIP") affect primarily relatively large projects with relatively long construction schedules. For utilities contemplating such investments, a current return on CWIP can be a very powerful inducement to undertaking them as it provides balance sheet support by providing both a source of cash and income (whereas AFDUC provides only book income that is not fully valued in rating agencies' views of credit quality). A return on CWIP also enhances investor confidence that the State supports the project.

Prices based on historic costs

Public Service needs clarification as to what the Commission means by this phrase. The Commission may be referring to the use of a historic test year for the determination of revenue requirements, cost allocation, and rate design. If so, Public Service believes that using a future test year would be more reflective of the costs that are actually incurred in the years that the rates are in effect, would reduce overall financing costs due to the reduction in regulatory lag, and would send to customers better price signals.

4. For the policy goals identified in your response to Question 1, please describe, at a high level, a revised regulatory structure (compared to the existing regulatory structure) that makes achievement of these goals more likely.

In evaluating regulatory alternatives it is crucial to consider the environment in which they will be applied. As explained above, Public Service is projecting growing infrastructure needs over the next decade. To ensure adequate physical infrastructure and to maintain excellent service quality, the regulatory paradigm must provide for the timely recovery of prudently incurred costs. There are two components to the regulatory lag discussed previously. The first component results from the use of a historical test year; the test year is stale even before the utility files its rate case. The second component is the interval between the utility's filing for rate relief and the Commission's approval of final rates. Both components of regulatory lag should be addressed.

Similarly, policy makers are requiring utilities to implement a variety of public-benefits programs. This new emphasis will require regulatory approaches that align the utility's financial incentives with public-policy goals. An increasing reliance on planning and up-front approval of resource decisions will also be required.

The goal of price stabilization will require some up-front approvals as to what level of stability is best, given the additional costs entailed. The tactics for achieving this stability must be reevaluated through some regulatory process to meet changing needs and goals. Public Service believes that the regulatory mechanisms currently in place – the annual reviews of price volatility mitigation plans for both the electric and gas utilities – are good mechanisms for achieving these goals.

The goals of equitably recovering costs and promoting customer choice will require some vehicle for periodically adjusting rates and adding tariff options to better reflect costs and send better price signals. The Commission will also need to evaluate carefully how "ability-to-pay" considerations should be captured in ratemaking and how utilities can be allowed timely cost recovery of low-income programs.

A wide spectrum of alternative ratemaking mechanisms could be used to meet these objectives. Some mechanisms involve only slight modifications to the existing cost-of-service model, while some entail a more dramatic departure. The following is a list of mechanisms that could be adopted alone or in combination with others to accomplish the goals provided in response to Question 1 above:

- <u>Pre-Approval of Utility Decisions</u>

  The Commission currently employs several periodic dockets to examine through public-hearing processes various utility proposals and to approve them before they are undertaken. These processes provide certainty to the utility that its plans are considered prudent and that cost disallowance will be minimized. Examples of this approach are the periodic resource-plan proceedings, the periodic DSM application proceedings, the annual Renewable Energy Standard Plan proceedings and the annual Price Volatility Mitigation (fuel hedging) proceedings. All of these dockets examine proposed plans prior to execution. These more collaborative processes further the goal of considering long-run costs by ensuring better decisions before-the-fact and assuring the investment community that the utility's actions are consistent with the preferences of the regulatory body.

Nonetheless, this regulatory tool or approach should not be confused with pre-approved cost recovery. The utility is still required to demonstrate that it has implemented these decisions in a timely and cost-effective manner. Along those lines, the Commission could provide financial incentives to encourage the utility to minimize costs and finish projects expeditiously.

- *Future Test Years*

  The application of a future or forecasted test year allows the Company to minimize the first component of regulatory lag (the gap between the test year and the filing of the rate case) and the concomitant adverse financial consequences of test-year ratemaking. In addition, the use of a forecasted test year ensures more equitable cost recovery, because the new revenue requirements are reflected in rates much closer to the beginning of the test year.

- *Timely Rate Implementation*

  The second component of regulatory lag (the lag between the filing date of the rate case and the Commission's approval of final rates) can be addressed through interim rates. In other words, the utility would be allowed to begin charging rates based on its proposed deficiency relatively soon after filing a rate case. The revenues recovered under the higher interim rates would be subject to refund, depending on the final rates that the Commission ultimately approves.

- *Multi-Year “Step-Rate” Plans*

  The application of a multi-year plan includes an annual step-rate adjustment to rates based on the traditional cost-of-service model applied to three or more future test years. California and New York have employed this approach. The test years may be based on the utilities forecasted budget for each year, or may be based on a first-year forecasted budget with known and measurable cost changes and/or escalation factors applied to the cost of service for subsequent years under the plan. This approach both assures timely cost recovery and provides an incentive to the Company to seek efficiencies between rate cases. It also accurately recovers costs from customers, because rates are based on future test years and adjusted to capture changes in the cost of service. In addition, a multi-year plan minimizes the frequency and costs of rate case proceedings. Most multi-year rate plans are combined with an earnings sharing mechanism to protect customers and shareholders from extreme over- or under-earnings.

- *Formula Rates*

Formula rates refer to rates that are changed periodically based on a pre-established formula. Cost and revenue changes in specific accounts in specific financial reports serve as the basis for annual rate adjustments. The Federal Energy Regulatory Commission uses formula rates to facilitate investment in transmission infrastructure.

- Earnings Sharing

  A form of sliding-scale regulation, earnings sharing mechanisms share with customers and shareholders any actual earnings that fall below or above established bandwidths. Shareholders absorb variations in actual earnings within the bandwidth. Some plans allow for annual price changes not to exceed a set level. The sharing of earnings below or greater than the allowed rate of return is predetermined. Depending on other ratemaking mechanisms in place, earnings deviations may accrue in a tracking account and captured through future rate adjustments, or may be combined with annual rate adjustments such as those implemented as a result of formula rates or step-rate mechanisms. The primary benefit of an earnings sharing mechanism is that the utility has a direct financial incentive to operate more efficiently between rate cases, but both customers and shareholders are protected from high levels of over- or under-earnings. These approaches can are being used for utilities in California, Connecticut and New York.

- Quality of Service Incentives

  The Commission could reward or penalize utilities based on their quality of service, using service metrics similar to those used for the Company's existing QSP Plan. The Company believes that such an incentive should be symmetrical, i.e., allow for rewards as well as penalties.

- Adjustment Clauses

  Even if the initiatives listed above are optimally deployed, there will continue to be a need for adjustment clauses. In general, significant costs that vary widely on a monthly or annual basis should still be collected through adjustment clauses such as the ECA and GCA. The PCCA needs to be retained as a cost-minimization device with respect to imputed debt. But depending on which of the other initiatives are employed, the need for adjustment clauses intended to facilitate investments by capturing annual changes in investment and O&M costs more accurately may be reduced or even eliminated. The need for adjustment clauses is discussed in more detail in response to Questions 6 and 11.

Finally, the Company believes that a couple of the commonly cited regulatory alternatives are not likely to be good solutions given the anticipated future challenges. Specifically, the Company believes that both the price-cap and revenue-cap models would not best achieve the goals identified in Question 1. Neither model can capture in a timely manner changes in costs during periods of increasing marginal costs or high levels of capital investment absent the use of a negative “x factor,” which is an anomalous and inconsistent use of a productivity adjustment. Revenue cap models assume static revenue needs or fixed growth in revenues. Consequently, such models also fail to account for large, lumpy capital investments.

5. Provide details of your proposed regulatory structure. The exposition should identify all assumptions, and take into account costs, cost reductions, financial effects on the company, and other relevant factors.

- ***a. In crafting your regulatory proposal, consider:***
  - ***i. What constitutes a "just and reasonable" rate for customers and for the utility? How does your structure ensure that such rates are achieved?***
  - ***ii. What productivity gains are available to an energy utility, and how should those be accounted for in the regulatory structure?***
  - ***iii. How should inflation be treated within the regulatory structure?***
  - ***iv. How should targets and incentives for service reliability and customer service be treated?***
  - ***v. What types of innovation, technological or otherwise, appropriately can be expected from an energy utility?***

b. ***Explain what modifications to present Colorado regulation would be necessary to implement your proposal. Would statutory changes be necessary?***

c. ***Explain any tradeoffs among the goals identified in response to Question 1 that would be caused by your proposal.***

d. ***How would your suggested regulatory structure affect the existing level and types of required regulatory resources (at regulatory agencies, at the utility, among interested parties)?***

e. ***Explain how the effectiveness of your proposed regulatory structure would be measured.***

At this time, the Company is not prepared to provide a detailed proposal for an alternative regulatory model for Colorado. In our response to Question 4 above, we provide an overview of the alternative mechanisms that we believe would advance the goals identified in response to Question 1.

6. ***Assuming this Commission continues to set rates using a relatively traditional ratemaking approach, through base rate cases with some cost adjustment mechanisms, please discuss the appropriate ratemaking adjustments between base rate cases.***

   a. ***What criteria should be used to determine the appropriateness of adjustments between rate cases?***

Adjustment mechanisms between rate cases may be appropriate for costs that meet one or more of the following criteria:

- The costs vary significantly within a year or between years.
- The costs are for a large investment or investments for which the traditional lag would impose incomplete cost recovery and impose significant financial harm on the utility.

Adjustment mechanisms are also good vehicles for ensuring the timely recovery of financial incentives that either remove financial disincentives to the provision of energy-efficiency programs or distributed generation, award superior performance in the utility's provision of DSM programs, or distribute penalties or awards pursuant to quality-of-service plans. Moreover, adjustment clauses can sometimes advance goals not typically associated with riders. For example, the PCCA actually lowers the costs to customers by allowing the utility to avoid the imputation of additional debt. Finally, adjustment mechanisms are sometimes appropriate because they facilitate meeting statutory provisions regarding cost recovery or rate impacts. The RESA may be a good example of such a mechanism.

b. What adjustment mechanisms are important to retain?

c. Explain how such adjustment mechanism promotes or impedes the goals identified in response to Question 1, above.

Public Service believes it is most important to retain the GCA and ECA, because fuel or commodity costs vary significantly within a year and should be recovered as accurately as possible from customers on a dollar-for-dollar basis. These adjustment clauses advance the goals of minimizing the cost of service (by reducing the Company's business risk and financing costs) and recovering costs from customers accurately.

The Company also believes that both the gas and electric DSMCAs should be retained, because they align the utility's financial incentives with the State's public-policy goals. The mechanisms that will be implemented on January 1, 2009, will promote this alignment for several reasons.

First, because energy-efficiency programs reduce revenues and earnings, the utility has a disincentive to pursue all cost-effective opportunities. The financial incentive component of the DSMCA mitigates this disincentive, while rewarding the utility for good performance. Second, the DSMCA allow the Company to collect its DSM costs on a current basis, thereby eliminating regulatory lag. Third, the DSMCA removes any financial incentive for the Company to reduce its DSM expenditures below some level built into base rates.

The Company believes the PCCA should be retained because it assists in reducing the costs associated with imputed debt. This advances the goal of minimizing the cost of service.

The Company believes the RESA should be retained to maximize the acquisition of renewable resources within the statutory limits of the two percent incremental cost cap. Public Service proposes to maximize the funds that are available for section 124 renewable resources by using a two percent RESA, in connection with the RESA deferred account, to bank and track the funds that have been approved by the General Assembly for this purpose.

The costs recovered through the TCA meet the two criteria for costs listed above. As explained previously, any sound regulatory structure must facilitate investments. The Company recognizes that the TCA is not the only option for meeting this goal. Nonetheless, the Company believes the TCA should be retained to the extent there continues to be any significant regulatory lag and transmission investment costs continue to increase significantly.

The AQIR originally did meet the goal of aligning the utility's financial incentive with the State's public-policy goals. But this adjustment clause is perhaps the least critical mechanism, as the annual levelized costs are reasonably stable and there are no foreseeable, additional large investments that would be subject to recovery through the AQIR.

d. What is the desirable interval between rate cases, if any?

It is impossible to specify an optimal interval. During periods of flat growth and low inflation, the interval could be relatively long. During periods of high inflation and high capital expenditures, the optimal interval would be shorter. The optimal interval would also depend on the number and scope of rate adjustments allowed between rate cases and the macroeconomic conditions prevailing at the time. For example, periods of very rapid inflationary increases will drive the need for more frequent rate cases.

e. What is the interplay between the use of future test periods and cost adjustment mechanisms?

As mentioned above, cost-adjustment mechanisms can be justified on a few fundamental bases. A forecasted test year does not significantly reduce the need for adjustment clauses whose purpose is to recover costs that vary significantly on a monthly or annual basis. The primary examples of such adjustment clauses are the ECA and GCA, and to a lesser extent the DSMCA. A forecasted test year still locks in cost recovery based on the costs projected for that year. The forecasts are very unlikely to be accurate for fuel or commodity costs. Even if the forecasts were accurate, some monthly or quarterly mechanism would still be needed to charge customers appropriately for the specific fuel or commodity costs incurred in a specific billing period.

A forecasted test year reduces the need for adjustment clauses whose purpose is to ensure more timely recovery of large investments or large increases in investment costs. Examples of such adjustment clauses are the TCA and AQIR. However, adjustment clauses are still appropriate when investment costs are expected to increase significantly from year-to-year, because rates based on forecasted test years cannot be changed rapidly enough to reflect the cost changes. If the preferred path of the State is to encourage increased levels of utility investments to meet public-policy objectives, it may be appropriate to facilitate increased levels of investment either by expanding riders or by adopting an alternative structure that achieves similar goals. A forecasted test year does not reduce the need for adjustment clauses if the utility has the ability to increase its earnings by reducing costs below test-year levels. An example of such a mechanism is the DSMCA.

In short, a forecasted test year may reduce the need for some of the current adjustment clauses, particularly the riders implemented to track changes in significant investment costs. But most adjustment clauses would probably continue to be necessary.

7. The concept of "incentive" sometimes refers to an inducement offered to encourage an activity which is voluntary. Compare this meaning of incentive to an approach by which regulators mandate an activity and then provide necessary "cost recovery" through rate adjustments or other regulatory mechanisms.

A commission can provide incentives by either mandating actions with the threat of penalties for noncompliance or offering an inducement to encourage a voluntary activity. In the first case the incentive is the threat of penalties or cost disallowances. In the second case the incentive is the financial reward for taking voluntary, positive steps towards the achievement of a goal.

Despite the fact that both approaches provide an incentive to achieve a desired goal, there are important differences. In the first case the incentive is for the utility to be a “compliance utility.” The utility will construe its objective as narrowly as possible and seek very explicit guidelines as to the compliance rules. As there is no upside for superior performance, the utility will likely do no more or no less than is necessary to comply. In the second case the utility will have a financial incentive to identify innovative ways to achieve the desired goal. The utility will strive for superior performance, up to the point that the cost of additional efforts begins to exceed the additional award attributable to these efforts. As such, Public Service believes that "carrots" are usually more effective than "sticks" in shaping utility performance.

8. Incentives or inducements can be either positive or negative. In what circumstances does one type generally work better than the other?

Either positive or negative incentives can be used to achieve goals. Negative incentives (such as penalties or cost disallowances) are more applicable when the goal is compliance with a specific requirement. An example might be meeting specific filing or other procedural requirements, following tariffs consistently, or complying with specific long-standing state or federal statutory requirements. In such cases the commission should allow timely and complete cost recovery of all reasonable costs necessary to achieve the goal.

Positive incentives are more effective when the desired outcome is not administrative compliance, but rather the achievement of public-interest goals for which there is uncertainty about both how best to achieve them and the best possible performance. In other words, this approach works best when the commission identifies bottom-line goals and requires and depends on the utility to identify and implement the best ways to achieve them. Examples would include encouraging the effective provision of DSM programs, minimizing fuel costs, efficiently managing large construction projects, maximizing margins from off-system sales, and minimizing the number and duration of customer outages. In such cases the commission should share the benefits resulting from the utility's initiatives between customers and shareholders, thus aligning the utility's financial interests with public-interest goals.

It is important to remember that an incentive mechanism cannot be deemed effective just because it provides the utility with some incentive – either through rewards or penalties – to achieve the desired result. Stakeholders could quickly identify a wide variety of Performance Based Regulation ("PBR") mechanisms that meet this criterion. An effective incentive mechanism must also limit the potential to improve performance in one area at the expense of worse performance in another area and allocate equitably the risks and rewards between customers and shareholders. These two criteria are more difficult to meet, and largely explain why the development of an effective PBR mechanism is a difficult and time-consuming task.

9. Please identify "incentives" or "inducements" that have been used in the past in Colorado. Which were effective and why?

Some examples of incentives that have been used in CO include the PBR plans approved as part of merger proceedings, the ECA incentive and the QSP. Also, as we discussed above, significant incentives or inducements have been provided to Public Service through targeted adjustment clauses. For example, the recovery of renewables costs through the RESA and ECA has provided a major inducement to Public Service to take a national leadership position in the acquisition of renewable resources.

In general, the Company believes the incentive mechanisms have met their intended goals, although by no means are the incentives perfect. The ECA incentives have provided a direct incentive to the Company to reduce cost to customers. As explained elsewhere in these comments, the Company believes the adjustment clauses have also facilitated investments that improve the quality of service, reduce costs to customers and facilitate the transmission of energy from remote renewable resources to our customers.

The QSP also provides an incentive for the Company to meet specified service-quality standards. But because the current QSP includes only a “stick,” the Company has no financial incentive to achieve service quality beyond the specified standards. The Company believes a more balanced incentive consisting of both penalties and bonuses would induce us to pursue additional service-quality improvements. (See the response to Question 8.)

10. For purposes of this question, define the term "incentive mechanism" as you will use it in your response. For each incentive mechanism currently in use in Colorado:

- ***a. Classify the mechanism as a positive or a negative incentive, and specify the behavior sought to be elicited by the mechanism.***
- ***b. Is the mechanism having the desired effect? How is this determined?***

Public Service has addressed this question through our earlier responses. In general, a positive incentive mechanism is one that provides the utility with an ability to enhance its earning through achieving specified public-policy goals. The earnings enhancements can take several forms, including but not limited to: the reduction or elimination of regulatory lag; increases in allowed returns; and the recovery of lost revenues due to energy efficiency. Public Service believes that all current rate incentives in its tariffs are having the desired effect and we take them all seriously.

11. Colorado gas and electric utilities collect a significant fraction of their total revenues through "rate riders." Please comment on any or all of the rate rider mechanisms in current use. For each mechanism you choose to address:

a. Do you view the rate rider as an incentive mechanism or as a rate mechanism that provides increased assurance of cost recovery? Please explain.

b. If you know, please state the amount of dollars collected through the mechanism annually for the past five years and state that as a percent of total revenues for each affected utility.

c. What was the change in the underlying metric (e.g., customer service, performance ratios, targeted investments) over the past five years?

<u>ECA – effective January 1, 2007</u>

The ECA is designed to recover, dollar-for-dollar, the Company's prudently incurred electric fuel, purchased energy and purchased wheeling costs. These costs are volatile, and the commodity prices are largely beyond the control of the Company. The ECA also includes a two-part incentive mechanism. First, there is an incentive based on the actual energy generated from coal-fired units compared with a benchmark. The monetary savings from coal-fired generation in excess of the benchmark are distributed to customers (80 percent) and shareholders (20 percent). Second, there is an incentive to encourage Public Service to pursue cost reductions through purchases of economical short-term energy. The total incentive payment to the Company in any calendar year is capped at $11.25 million.

a. The ECA is a mechanism that primarily provides more timely and accurate cost recovery, but also includes an incentive component.

b. The amounts that the Company has collected under the ECA (or its predecessors) in total and as a percentage of total retail revenue are shown below:

	Amount Collected	% of Retail Revenue
2003	$176,008,096	9.97%
2004	$263,251,816	14.73%
2005	$604,264,912	30.23%
2006	$832,847,591	40.38%
2007	$718,724,485	33.90%

c. Not applicable.

PCCA – effective January 1, 2007

The PCCA recovers all purchased power capacity costs. Prior to January 1, 2007, Public Service recovered the capacity costs for certain purchased power contracts through the PCCA, and recovered Qualifying Facilities purchased capacity costs through the Qualifying Facility Capacity Cost Adjustment.

a. The PCCA is a mechanism that allows for more timely and accurate cost recovery. The PCCA also reduces the level of the imputation of debt associated with PPA capacity payments, thereby reducing costs to customers.

b. The amounts that the Company has collected under the PCCA (or its predecessors) in total and as a percentage of total retail revenue are shown below:

	Amount Collected	% of Retail Revenue
2003	$ 5,178	0.00%
2004	$10,972,228	0.61%
2005	$30,660,596	1.53%
2006	$ 7,362,477	0.36%
2007	$12,564,125	0.59%

c. Not applicable.

GCA – effective November 1, 2004

a. The GCA is a mechanism that allows for more timely and accurate cost recovery of gas commodity costs.

b. The amounts that Public Service has collected under the GCA (or its predecessors) in total and as a percentage of total retail revenue are shown below. Only calendar years 2005 through 2007 were readily available.

	Amount Collected	% of Retail Revenue
2003	$	
2004	$	
2005	$ 992,914,433	77.25%
2006	$ 957,942,404	75.20%
2007	$ 848,336,655	71.04%
2008	$ (through August)	

c. Not applicable.

AQIR – effective January 1, 2003

The AQIR is designed to recover costs that Public Service voluntarily incurred to reduce emissions from the Cherokee, Arapahoe and Valmont power plants. Senate Bill 98-142, codified as article 3.2 of title 40, C.R.S., authorized the recovery of the air-quality improvement costs. The costs subject to recovery through the AQIR are recovered over 15 years.

a. The AQIR is a mechanism that allows for more timely and accurate cost recovery. This feature also provides the utility with an incentive to invest in the targeted air-quality improvements.

b. The amounts Public Service has collected under the AQIR in total and as a percentage of total retail revenue are shown below:

	Amount Collected	% of Retail Revenue
2003	$32,562,989	1.85%

2004	$32,493,925	1.82%
2005	$30,374,839	1.52%
2006	$30,933,157	1.50%
2007	$27,938,378	1.50%

c. Not applicable.

<u>Electric DSMCA – effective 1990</u>

The electric DSMCA is designed to recover the costs and financial incentives for Company-sponsored DSM programs. The Commission has modified the DSMCA several times since 1990. The assessment of the electric DSMCA provided in parts "a" and "c" below pertains to the mechanism the Commission recently approved for implementation on January 1, 2009.

a. The electric DSMCA provides both more accurate and timely cost recovery and a greater incentive for the Company to implement DSM programs effectively.

b. The amounts Public Service has collected under the electric DSMCA in total and as a percentage of total retail revenue are shown below:

	Amount Collected	% of Retail Revenue
2003	$ 4,449,038	0.25%
2004	$ 7,326,548	0.41%
2005	$11.767,632	0.59%
2006	$17,180,661	0.83%

2007	$26,724,260	1.26%

c. Not applicable.

Gas DSMCA – effective 1992

The gas DSMCA is designed to recover the costs and financial incentives for Company-sponsored DSM programs. The Commission has modified the gas DSMCA several times since 1992. The assessment of the gas DSMCA provided in parts "a" and "c" below pertains to the mechanism the Commission recently approved for implementation on January 1, 2009.

a. The gas DSMCA provides both more accurate and timely cost recovery and a greater incentive for the Company to implement DSM programs effectively.

b. The amounts Public Service has collected under the gas DSMCA in total and as a percentage of total retail revenue are shown below. Only calendar years 2005 through 2007 were readily available.

	Amount Collected	% of Retail Revenue
2003	$	
2004	$	
2005	$ 3,337,563	0.26%
2006	$ 3,589,568	0.28%
2007	$ 3,968,793	0.33%

c. Not applicable.

RESA – effective 2006

The RESA recovers the incremental costs of new renewable resources (over the costs of avoided non-renewable resources) that have been acquired after the passage of Amendment 37, which established the RES. In 2007, HB07-1281 expanded the RES beyond the requirements of Amendment 37.

a. The RESA is a mechanism that provides more accurate and timely cost recovery. It is also a mechanism that will be used to bank and track funds collected within the bounds of the retail rate impact limits in C.R.S. §40-2-124(1)(g) to maximize the acquisition of renewable resources by Public Service.

b. The amounts Public Service has collected under the RESA in total and as a percentage of total retail revenue are shown below:

	Amount Collected	% of Retail Revenue
2003	$0	0%
2004	$0	0%
2005	$0	0%
2006	$ 9,446,233	0.46%
2007	$12,564,125	0.60%

c. Not applicable.

TCA – effective January 1, 2008

The TCA recovers increased investment in transmission facilities since the Company's last rate case, as provided for in SB07-100. The TCA also includes the recovery of a current return on CWIP.

a. The TCA is a mechanism that provides both more timely and accurate cost recovery and the Company with a financial incentive to upgrade and extend its transmission system.

b. The amounts Public Service has collected under the TCA in total and as a percentage of total retail revenue are shown below:

	Amount Collected	% of Retail Revenue
2003	$0	0%
2004	$0	0%
2005	$0	0%
2006	$0	0%
2007	$0	0%

c. Not applicable.

12. Should the Commission provide jurisdictional utilities with either a positive or negative incentive to achieve certain levels of emissions reduction? If yes, what incentive mechanisms can most effectively assist in achieving those emission goals? What are the benefits and the practical problems associated with the mechanisms?

Well-designed incentives are an appropriate means of motivating utility innovation. But such efforts entail trade-offs, because going beyond the emissions standards set forth in state and federal statutes would usually increase costs and rates. The Commission has no jurisdiction to create any “negative” incentive with respect to emission reductions. Utilities are legally entitled to operate within the bounds of their air permits issued by other state agencies. The Commission could provide utilities with positive incentives to achieve emissions reductions beyond the levels required under environmental laws, if the Commission believed such reductions were in the public interest.

Various incentive mechanisms could be used to achieve such goals. For example, utilities could be provided a “bonus” ROE for making investments that dramatically reduce the emissions of one or more regulated pollutants at an existing power plant. Reducing energy consumption and peak demand is another means of reducing emissions, and this could be accomplished through aggressive energy-efficiency and demand-response programs that offer incentives to the utility.

Regarding the structure of the potential incentives, any incentives designed to foster emission reductions needs to be carefully crafted to ensure that they are properly directed and strong enough to get management’s attention. The metrics also need to be “realistic” – overly ambitious goals may discourage the utility from taking more modest actions that could yield significant environmental benefits. As is the case with all incentive mechanisms, the criteria on which the incentives will be based need to be transparent and unambiguous, to avoid excessive after-the-fact litigation as to whether the utility has earned a financial reward. In addition, ratemaking policies should ensure that prudently incurred costs are recovered in a timely manner.

13. It is often said that regulation should function to induce utilities to be efficient in the absence of competitive pressures that would induce that behavior otherwise.

a. Do you agree with this premise?

b. What methods exist to measure the efficiency of a utility operating in Colorado?

c. What types of efficiency are appropriate for regulators to measure?

d. What regulatory mechanisms are best suited to induce a utility to become and remain efficient? Should the related incentives be positive or negative?

The Company agrees that one important objective of utility regulation is to encourage utilities to perform as efficiently as possible. Utilities are subject to some competitive pressures outside of the regulatory arena. As the cost of electricity and natural gas continue to rise, customers are increasingly encouraged to examine alternatives for meeting their energy needs. Some options include energy efficiency, fuel switching, bypass of the local gas distribution utility, or moving to locations with lower energy costs. All of these options could impair the utility’s earnings between rate cases; therefore, they serve as an incentive for the utility to operate efficiently and maintain low rates.

The primary indicator of utility efficiency is the reasonableness of the price to customers. Specific indicators of a utility's efficiency include its cost per MWh (or therm) or customer. Utility performance can be assessed by either measuring changes in such costs over time or by comparing the utility's costs in a given year with those of a group of peer utilities. Another performance barometer might be a comparison of industry productivity trends with changes in a specific utility's productivity over the same period. This approach would require econometric modeling and the availability of comparative data.

Reaching sound conclusions based on specific performance metrics is very difficult. In applying any of these comparisons, it is important to determine if there are unique utility characteristics that affect the comparability of results. Moreover, efficiency measures must be established carefully to ensure that they are aligned with the objectives identified in Question 1 and do not encourage improvement in one area at the expense of worse performance in another area. Other factors that should be considered before using a given efficiency measure include the availability of accurate and timely data, the relevance of the measure to overall goals, the costs of tracking and analyzing performance, and the impact of using the measure on both short- and long-term regulatory strategies.

14. Does the use of future-test-year concepts in conjunction with traditional rate-base rate-of-return principles modify the need for some or all of other special cost recovery and utility incentive mechanisms? Please explain your answer.

By reducing the regulatory lag, the use of a future test year minimizes the need for adjustment clauses whose purpose is to track significant changes in investment-related costs between rate cases, i.e., investment riders. The AQIR and TCA are the two adjustment clauses that can be properly considered investment riders. But as explained above, there is a recovery lag even with future test years. Moreover, the costs of large capital investment programs with multiple projects spanning multiple in-service years will not be captured adequately through the use of forecasted test years. Consequently, it is unclear whether either of these specific adjustment clauses should be eliminated.

15. From a utility perspective, can additional system efficiencies be derived from using alternative retail rate structures (e.g., seasonal, time-of-day, inverted block rate structures, real-time pricing)?

The Company's current base rates for gas and electric service are generally flat, in that there are relatively few variations to reflect changes in costs by time of use. Rate structures that reflect the higher costs of service during periods of high demand on the system could encourage customers to reduce their peak demands or energy use during high-cost periods. The result would be a more efficient use of the Company's generating capacity and fewer subsidies among customers. The Company believes appropriate pricing is a key component of any strategy to maximize system efficiencies.

Examples of such rate structures include time-of-day rates, critical-peak pricing, and real-time pricing. Historically, these structures have proven to be difficult to implement for small customers, because the additional costs of metering and administering the rates have exceeded the expected benefits. The Company's *SmartGridCity* initiative will provide valuable experience with more sophisticated pricing, and may lead to more economically efficient rate structures in the future.

16. Are price cap regulatory regimes compatible with regulatory regimes that permit multiple pass-through rate elements? Why or why not? Please indicate what riders are and are not compatible or appropriate with price caps.

Price caps can co-exist with multiple pass-through rate elements as long as all costs associated with each mechanism are separately tracked. For example, price caps may be applied to base rates, while fuel costs continue to be recovered through a fuel clause adjustment. In this example, the index and productivity factor used to determine the base-rate adjustment would need to be formulated such that it did not include consideration of fuel costs.

Since a price-cap regime is most applicable when costs are forecasted to remain relatively steady, a utility facing increasing capital expenditures in a rising incremental cost environment would still require automatic adjustment mechanisms to reflect and recover changes in these costs. As mentioned in response to Question 4, a price-cap regime by itself does not effectively recognize increasing levels of capital expenditures. In general, for the reasons we have already discussed, Public Service does not believe that price-cap regulation would be an appropriate regulatory model for Colorado at this time.

17. What criteria should the Commission consider in evaluating the effectiveness of a utility's "buy" vs. "bid" decisions? How effective is the "risk of imprudence" in disciplining a utility's costs when the utility builds a project? Is there a quantifiable measure for optimal ownership by the utility? Explain.

As Public Service discussed at length in our testimony in Docket No. 07A-447E, there are hard-to-quantify optionality benefits associated with generation plant ownership that provide operational flexibility and extended value and cost savings, when compared with term-limited PPAs. As such, we do not believe that PPAs can be compared head-to-head against rate-based utility generation to determine which is the better option overall.

The Company pointed out that there are different risks and rewards associated with PPAs and Company-owned generation. Consequently, the Company recommended that the prudent course of action would be for the utility to include both owned generation and PPAs in its portfolio. We explained that, compared with other utilities of our size, Public Service has too much purchased power in our portfolio and we need to rebalance the portfolio with more rate-based generation. We also offered a plan for achieving this rebalancing. Specifically, the Company proposed to replace its retired coal capacity with owned generation, as well as meet 40 to 60 percent of its incremental capacity needs through owned generation. The Commission has agreed with the concept of rebalancing the portfolio, but has reserved judgment on the appropriate balance until generation proposals are reviewed in Phase 2 of the Company's 2007 resource plan.

In Docket No. 07A-447E, we also explained that there are hidden costs associated with purchased power, because these contracts create imputed debt affecting utility credit ratings. We also explained the changing rules with respect to capital leases and how certain power purchase contracts might be required to be reflected on utility financial statements as capital leases. Further, we expressed our concern about possible consolidation for financial reporting purposes of the special purpose entities that sell power to us under PPAs.

The risk of cost disallowance due to construction imprudence provides a significant incentive for the utility to limit actual project costs to estimated levels. Public Service takes pride in managing its construction projects to meet budgeted estimates. Our construction cost estimates include amounts for unforeseen contingencies in our budgeting, as is appropriate with large capital projects. We have internal controls to keep our projects proceeding along paths that complete generation projects on-time and within budget. We know that if our project cost exceeds our best estimate, we need to explain that difference to our regulators -- and that our explanation needs to be a good one.

18. What alternative ways (rather than rate base times rate-of-return) can be used to calculate a profit opportunity incentive for utilities? (e.g., operating

ratio, performance-based ratemaking, indexed rates, etc.) What are the benefits and concerns associated with such alternative mechanisms? What are the effects of such mechanisms on the commission goals identified above, both in the long-run and in the short-run?

Some performance-base alternatives for establishing a utility's rate of return include price-cap regulation, revenue-cap regulation, and price indexing.

There are also different ways to implement the traditional regulatory approach (rate base times rate of return) used in Colorado. Among these alternatives are formula rates; multi-year, multi-step ratemaking; rate cases filed according to pre-established schedules; the use of future test years; and interim rates.

As explained in our response to Question 4, the Company is not convinced that any of the commonly cited performance-based alternatives can substitute for traditional cost-of-service regulation -- given the likely future challenges the Commission and utilities will be facing. Nonetheless, as explained in detail throughout our responses, the Company believes that various performance-based incentives can be used in conjunction with traditional cost-of-service regulation. Moreover, the current approach to implementing cost-of-service regulation could be modified to better meet the identified goals. The use of future test years and multi-year, multi-step ratemaking are two promising modifications.

At a later date the Company will provide a summary of different regulatory models used in other states.

19. Some argue utilities should properly receive extra "incentives" to provide DSM and energy efficiency programs. Others assert that it is counterintuitive to offer to utilities inducements to sell less electricity, when their history, purpose and culture all point towards selling more electricity. These commentators point to successful programs administered by non-utilities such as Vermont Efficiency or the Oregon Energy Trust. We invite comment on this debate as it applies to Colorado.

In assessing the need for “extra incentives,” it is first important to recap the necessary conditions under which the utility has no financial disincentive to implement DSM programs. The next step is to evaluate whether the utility can and should be rewarded for achieving more DSM or higher DSM-related net benefits. These aspects of implementing DSM programs were fully discussed in both the Commission’s natural-gas rulemaking on DSM programs and Public Service’s electric DSM proceeding (Docket No. 07A-420E). In general, the disincentive can be removed through timely cost recovery through a rider and the recovery of lost margins -- either directly or through a performance-based incentive.

By definition, successful energy-efficiency programs reduce a utility’s sales of gas or electricity. To the extent that the utility’s rates are structured to recover fixed costs through volumetric rates, and these volumes are reduced because of the installation of DSM measures, then the utility’s profitability (relative to what it would have been absent installing these measures) is reduced. In the DSM proceedings mentioned above, it was generally recognized that such “lost margins” constitute a genuine disincentive that needs to be addressed. These problems exist irrespective of whether the utility or another entity administers the DSM program.

The utility can be encouraged to implement programs effectively through an incentive tied to savings actually achieved and/or the net benefits of the DSM programs. DSM initiatives can then become more attractive to the utility, because it can earn relatively more from managing DSM activities than from managing other aspects of the utility's core businesses. As has been previously represented to the Commission, Xcel Energy's utility DSM programs, particularly those in Minnesota, have been very successful, cost-effective and award-winning. The Colorado General Assembly, in enacting HB07-1037, has required the Commission to allow an opportunity for utility investments in cost-effective DSM programs to be more profitable to the utility than any other utility investment that is not already subject to special incentives.

As the question infers, there are alternative ways of implementing and administering DSM programs – the Vermont and Oregon's practices are two examples. At this time, Public Service cannot assess or comment on the success of these programs. As with so many other aspects of the regulation of public utilities, it is important to understand and appreciate a state's DSM goals, the specific contexts of a state's regulatory structures, and the abilities and sizes of the utilities involved, before concluding that any alternative structure is appropriate and preferable to that currently in place in Colorado.

The Vermont Efficiency, Oregon Energy Trust and NYSEDRA are cited frequently as evidence that third parties can successfully administer energy-efficiency programs. By the same token, there are many examples of successful utility-administered programs across the country.

a. ***Assuming DSM and energy efficiency programs remain a high priority for this Commission, are utilities likely to be the preferred providers, or should alternative providers be considered? Does your answer depend on the program? Please explain in detail.***

Public Service believes that customers benefit from the utility's administration of DSM programs. Xcel Energy's experience suggests that utilities can effectively develop, manage, deliver and administer DSM programs. Offering our customers expertise and rebates to help them manage their energy use and to reduce their utility bills is a very positive component of our overall provision of energy services. When these programs are effectively delivered, they increase customer satisfaction; the utility can demonstrate that we are actively working with and providing the means (through rebates) to customers to reduce their bills. It is important to clarify and emphasize that in offering DSM programs, Xcel Energy relies extensively on third-party entities of all types to successfully market and implement its DSM programs.

As previously stated, there are viable alternatives to utilities for administering and delivering DSM programs. For example, it is possible to fund DSM programs through public-benefits charges collected by utilities and remitted to a governmental agency or other non-utility entity to plan, implement and administer DSM programs. But there are several factors to consider before adopting the non-utility model.

First, if a utility administers the programs, then the funds generated from the utility's public-benefit charge are spent for the benefit of that utility's customers. But if the funds collected flow to a third-party administrator, there may be transfer payments from one utility's customers to another utility's customers. This, in turn, raises a fundamental question about whether the funding for third-party initiatives should be generated through utility-administered public-benefits charges or more directly through the imposition of a statewide tax.

Second, Public Service believes that our administration of DSM programs benefits customers. Customers know us and consider us a neutral source for advice and information. They trust us to maintain the confidentiality of any data they share with us. This relationship helps our sales, marketing and promotional efforts. Our account managers have access to customers that third-party administrators may find hard to achieve. Third-party administrators have stated that they can more easily gain access to customers if they are associated with an Xcel Energy program.

Third, Public Service can use known customer data to efficiently market programs. Currently, customer usage and bill information is deemed confidential and proprietary; this information is not provided to any third party without the customer's expressed consent. The wholesale transfer of customer billing and usage information to outside entities, while maintaining the same confidentiality safeguards and limitations on the usage of such information, prompts concern that would need to be addressed if third-party administration is contemplated.

b. ***Even if non-utility entities were to provide some DSM and energy efficiency programs, are there activities that only the utility can perform because of its indispensable role in providing electric service?***

There are very few DSM activities that can be provided only by utilities, and these primarily relate to demand-response programs such as Saver's Switch or the implementation of the Company's Interruptible Service Option Credit program. The activation and oversight of these programs are indispensably tied to the daily and hourly management of the Company's supply and delivery systems. That being said, third-party suppliers already install some of the switches, meters and communications devices required for the programs.

Even if the Commission decided to use a third-party provider, the Company would continue to encourage customers to conserve energy and to avail themselves of energy-efficiency programs. The Company's active involvement in marketing DSM programs will vary by program and customer type. Currently, the Company assigns individual account managers to our largest customer accounts. Included among the account managers' responsibilities is helping customers identify DSM opportunities. Regardless of the entity that ultimately administers DSM programs, our account managers will continue these activities.

c. ***To the extent non-utilities can provide programs requiring only a "normal" profit, is it likely that the cost of energy efficiency programs could be lower if a non- utility entity offers the same programs? What is***

the rationale for offering extra inducements to the utilities to offer those same programs?

This question raises the issue of what is considered a “normal” profit. In the context of utility regulation, there is absolute transparency regarding an investor-owned utility’s earnings. The profits (or allowed returns) are normally set in the context of an open rate proceeding. This is done in recognition of the monopolistic -- and therefore price-regulated -- status of the utility. For numerous reasons, the overall profitability of a regulated utility is lower than the profitability of competitive, for-profit firms. As a result, the identified “normal” profits for non-utilities are probably higher that those allowed for regulated utilities. Consequently, non-utility entities cannot necessarily provide programs at a lower cost than utilities. It is also possible (but not suggested) for the government itself to offer DSM programs. Governmental provision of DSM programs would eliminate the need for “profits,” but not for the recovery of other DSM costs. The need to ensure timely cost recovery, allow for the recovery of lost margins, and provide positive incentives linked to performance has already been addressed.

20. Does a utility's obligation to serve under Colorado law include only the obligation to sell power or does it also include the obligation to find the least cost means of meeting customers' demands, even if that includes ways to reduce demand?

A public utility has the obligation under Colorado law to provide reliable service at just and reasonable rates. What constitutes "just and reasonable rates" can be influenced by statutory enactments, rules promulgated by the Colorado Public Utilities Commission, and legal orders issued by the Commission.

The Colorado General Assembly has recently enacted specific legislation, HB07-1037, requiring electric utilities to reduce customer demand for electric power. Further, there is no longer any statutory or rule obligation for electric utilities to find the *least cost* way of meeting customer electric demands. Recent legislation enactments, e.g., HB07-1281, HB06-1281, and HB08-1164, all contemplate that the electric utility may acquire resources that are not least-cost resources to achieve other public-policy objectives. The Commission has revised its Electric Resource Planning Rules to remove the obligation for "least cost" resource acquisition. Given the difficulty in measuring the level of demand reductions that could reasonably and prudently be achieved by a particular utility, each with a somewhat unique customer mix, any required savings goals are typically implemented with some form of positive incentive to allow for deployment of the maximum level of cost-effective conservation.

21. Do traditional rate base/rate-of-return regulatory structures disadvantage energy efficiency programs? Why or why not? If yes, what modifications could be made to traditional rate base/rate-of-return to mitigate this disadvantage?

These questions have been thoroughly addressed above, as well as in other proceedings.

22. How does decoupling (of revenue and sales) interplay with utility incentives to roll out DSM and other energy efficiency mechanisms?

The basic goal of full revenue decoupling is to eliminate any impact of changes in customer use on the utility's earnings. There are various ways to accomplish this goal. One way is to eliminate usage charges. Another way is to assess riders that adjust for variations between the revenues per customer actually collected through usage charges and the revenues per customer assumed to be collected through usage charges in the last general rate proceeding. All else being equal, full revenue decoupling would facilitate the implementation of DSM programs by either the utility or a third party, since lost margins would be eliminated. This outcome is different from the outcome under the existing regulatory regime.

V. CONCLUSION

Public Service Company of Colorado looks forward to further discussion of these matters with the Commission and other interested parties. We appreciate the opportunity to review the comments submitted by others and we reserve the right to respond to those comments. We also may supplement these comments as allowed under the Commission's procedural schedule.

Dated this 22nd day of September, 2008.

Respectfully submitted,

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CERTIFICATE OF SERVICE

08I-113EG

I hereby certify that on this, the 22nd day of September 2008, an original and ten (10) copies of the foregoing **SECOND ROUND OF COMMENTS BY PUBLIC SERVICE COMPANY OF COLORADO** were served via hand delivery on:

Doug Dean, Director
Colorado Public Utilities Commission
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and a copy was also served electronically on all parties on this service list:

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