Final Report

Preliminary Municipalization Feasibility Study

City of Boulder, Colorado

October 2005

R·W·BECK

CITY OF BOULDER, COLORADO
PRELIMINARY MUNICIPALIZATION FEASIBILITY STUDY

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EXECUTIVE SUMMARY

Introduction

The City of Boulder, Colorado ("City") currently has a franchise agreement with Public Service Company of Colorado to provide its electric and natural gas utility service. This franchise agreement provides Public Service Company of Colorado the right to utilize the City's street, public places and public easements to serve its citizens. Following voter approval, this franchise was granted effective August 3, 1990. After this franchise agreement was approved, Public Service Company of Colorado became Xcel Energy, Inc. For the purposes of this report, Public Service Company of Colorado is referred to as Xcel.

The franchise agreement expires on August 3, 2010. The City felt it would be prudent to identify the costs and risks associated with creating and operating a municipal utility. Therefore, the City is conducting an investigation of the logistics, costs and benefits of municipal control of its electric utility. As part of this effort, the City has retained the services of R. W. Beck, Inc. ("R. W. Beck") to provide financial and engineering support to City staff. These services include the development of a Preliminary Municipalization Feasibility Study ("Study").

R. W. Beck reviewed various facets of the City's existing electric system, including the distribution system, the transmission system, and the nearby generation station. Further, R. W. Beck reviewed the annual reports regarding the existing natural gas distribution system. Based upon our review, R. W. Beck recommends that if the City moves forward with its municipalization efforts, it should limit its effort to the electric distribution system only.

Physical Review, Severance, Stranded Investment

A limited field review was conducted to determine the relative condition of the poles, wires (conductors), and low-end of the substations. The condition of the portion of the distribution system observed ranged from good to excellent. Additionally, while conducting the field review of the physical condition of the system, additional services such as severance costs were also evaluated.

Severance

To operate as a municipal utility, the City will have to acquire certain existing Xcel assets. This will require the City to segregate the existing system that serves the City from the system that serves the general Boulder area. The cost estimate associated with segregation of the facilities is referred to as the "severance cost." Review of the severance analysis suggests that preliminary severance costs for the City are approximately $5 million. Depending on specific issues identified during further investigations, this value may need to be adjusted.

Stranded Investment

The Federal Energy Regulatory Commission ("FERC") will likely determine the issue of stranded investment costs. There is a sound factual basis for the City to argue that no stranded costs exist in this situation. Therefore, R. W. Beck's opinion should be considered a conservative and preliminary approach to this issue. For illustrative purposes, we have calculated a cost associated with stranded investment based on public information and assumptions. For the purposes of our preliminary analysis, we have assumed a value of approximately $20 million. The ultimate market price for power will have a large impact on the stranded investment determination, as well as the length of time Xcel could reasonably expect to serve the City's load (which could result in zero stranded investment costs).

Cash Flow Analysis

A cash flow analysis was prepared to model the projected operations of a municipal electric distribution utility. The model projects utility revenues, operation and maintenance expenses, capital requirements and reserve levels. After these cash obligations have been met, the model calculates any remaining free cash flows ("FCF") available for debt service payments. The present value of the cash flows represents the maximum amount the City could pay for Xcel's distribution assets and still meet all the financial goals and objectives of a municipal utility.

FCF is a function of rate revenues and operating costs. This modeling approach allows the City to evaluate various competitive rate scenarios and the corresponding purchase price of the assets. Major revenue and cost components of the model having significant impact on FCF are:

- Rate Revenues
- Purchased Power Costs
- Operation and Maintenance Costs
- Payment to the City In Lieu of Tax
- On-going Capital Requirements
- Cash Reserves Requirements and Financing Assumptions

Purchase Price Analysis

The Purchase Price Analysis discusses the worth of the assets to the City under various valuation perspectives. The book value of the assets (original cost less depreciation, "OCLD") and the reproduction value of the system (reproduction cost new less depreciation, "RCNLD") are compared to the FCF analysis described above. The book and replacement values have been determined from Xcel's Annual Reports to the City, which are based on an allocation of Xcel's entire system to the City's system. We requested information from Xcel to determine this allocation methodology; however, it was not provided. Our conclusions are qualified accordingly.

We developed purchase price scenarios under three different rate assumptions to illustrate the sensitivity of worth to rate levels. These scenarios are as follows:

- Base Case – Assumes that the City's average retail rate will be equal to Xcel's average retail rate over the study period.
- Below Xcel Case – Assumes that the City's average retail rate will be 5 percent less than Xcel's average retail rate over the 10-year study period.
- Above Xcel Case – Assumes that the City's average retail rate will be 5 percent greater than Xcel's average retail rate over the 10-year study period.

The results of these case flow analyses are summarized in Table ES-1 below.

Table ES-1
Free Cash Flow Analysis
Worth Under Various Scenarios

Case	Worth Excluding Severance and Stranded Investment	Worth Including Severance and Stranded Investment
Base Case	$105.9 Million	$80.5 Million
Below Xcel Case	$75.2 Million	$49.9 Million
Above Xcel Case	$136.5 Million	$111.1 Million

Another important assumption impacting system worth is power supply costs. Table ES-2 shows the impact on worth under the base case assuming that power costs were slightly higher or lower than those projected.

Table ES-2
Free Cash Flow Analysis
Base Case Worth Under Purchase Power Variations

Case Variation	Worth Excluding Severance and Stranded Investment
Base Case (16% markup)	$105.9 Million
Scenario 1 - Base Case w/ 15% markup	$112.6 Million
Scenario 2 - Base Case w/ 17% markup	$99.2 Million

As indicated in Table ES-2, a 1 percent change in markup of power supply costs results in a 6 percent change in system worth. Therefore, the worth of the system is highly sensitive to power supply costs. For the purposes of this Study, the costs associated with alternative energy power supply options have not been evaluated.

When assuming no stranded investment and minimal severance costs with rates set at the Xcel average system rates, the worth of the system to the City fell between OCLD and RCNLD. When rates are set 5 percent above the Xcel average system rate, the worth exceeded the RCNLD.

Conclusions

The financial analyses conducted for this Preliminary Feasibility Study suggests that there is a reasonable expectation that the City could acquire the Xcel distribution facilities within the City for an amount between the estimated book value of the assets (approximately $93 million) and their estimated replacement value (approximately $123 million). This analysis assumes that the City's average retail rate will be equivalent to Xcel's forecasted average retail rate during the study period. R. W. Beck's analysis is predicated on several issues related to the market price for power, including availability and cost, and costs associated with municipalization, including stranded investment and severance.

The purpose of this Preliminary Feasibility Study was to identify significant issues that would preclude the City from moving forward with its municipalization analysis. The results did not identify any such significant issues. R. W. Beck identified specific technical, economic, legal and political issues, as noted herein, that warrant further review by the City to determine if municipalization should be pursued.

Section 1
INTRODUCTION

Background

The City of Boulder, Colorado ("City" or "Boulder") currently has a franchise agreement with Public Service Company of Colorado to provide its electric and natural gas utility service. This franchise agreement (Ordinance 5569, PO-9302) provides Public Service Company of Colorado the right to utilize the City's street, public places and public easements to serve its citizens. In exchange for this right, the City receives an annual franchise fee and certain other rights from Public Service Company of Colorado. Following voter approval, this franchise was granted effective August 3, 1990. After this franchise agreement was approved, Public Service Company of Colorado became Xcel Energy, Inc. For the purposes of this report, Public Service Company of Colorado is referred to as Xcel.

The franchise agreement expires on August 3, 2010. The City felt it would be prudent to identify the costs and risks associated with creating and operating a municipal utility so the City Council, as well as Boulder's voters, would have information on a full range of service options when they make a decision on whether to renew a long-term franchise with Xcel. Therefore, and in recognition of the rights described in the franchise agreement, the City is conducting an investigation of the logistics, costs and benefits of municipal control of its electric utility. As part of this effort, the City has retained the services of R. W. Beck, Inc. ("R. W. Beck") to provide financial and engineering support to City staff. These services include the following Preliminary Municipalization Feasibility Study ("Study").

This report provides a description of the reviews conducted and services provided by R. W. Beck. These included a condition assessment and field review of the distribution system, a limited development of acquisition costs for the system, and an estimation of costs associated with severance and potential stranded investment. R. W. Beck also developed a cash flow analysis of the existing distribution facilities to estimate a value that the system represents to the City. Additionally, we developed recommendations and action plans for the City should it pursue this municipalization effort.

Data Limitations

As part of the franchise agreement, Xcel is required to provide the City with various types of information and reports. This includes reports, which provide annual electric and gas revenues received from residents of the City, as well as all components of the rate base used for calculation of return. Additionally, the franchise agreement requires

Xcel to provide a list of property it owns in the City, its capital improvement plans and other data. On March 30, 2005, the City Manager's office provided Xcel with a data request pursuant to the franchise agreement (a copy is provided as Attachment A). A response to this data request was provided on July 15, 2005. However, much of the information provided was incomplete or already available via public sources. The analysis reported herein has been updated as applicable with this information and utilizes preliminary assumptions based on other data sources and R. W. Beck's expertise. The limitations in the data provided by Xcel require R. W. Beck to qualify our conclusions and reinforce the premise that this Study is preliminary in nature.

Our Approach

As mentioned above, R. W. Beck reviewed various facets of the City's existing electric system, including the distribution system (within the City boundaries), the transmission system (several 115-kV lines run through the City), and the nearby generation station (the Valmont power station ["Valmont"] located just east of the City). Further, R. W. Beck reviewed the annual reports regarding the existing natural gas distribution system. Based upon our review, R. W. Beck recommends that the City should limit its municipalization efforts only to the electric distribution system due to the following reasons:

- The Valmont power station is not a desirable power supply option.
- Generation and transmission assets will add significantly to the acquisition cost.
- Operating a generating station, participating in the wholesale power market, and adding Federal Energy Regulatory Commission ("FERC") oversight to the operations and management responsibilities of the City will significantly add to the complexity of a utility startup.
- The natural gas system data is incomplete and is not useful in making a determination of the economics associated with acquiring the gas distribution system.

Local Generation

Assuming the City could extend its municipal boundaries to include the area around Valmont, R. W. Beck does not recommend that the City pursue acquiring this asset. Valmont is an old station that relies on outdated technology and it is not economically efficient to operate and maintain compared to cheaper power available in the power market. The key point here is that the City should be able to achieve a lower cost of power from market sources other than Valmont.

Also, Valmont is not suited to follow the city load fluctuations in an economical manner and while Valmont provides power to the City, it also serves Boulder County (and other loads in the area).

Due to various FERC rulings, a vibrant wholesale power market has been established across the country. This allows distribution-only utilities, such as the City, the ability to optimize their power supply from various competitive suppliers and not be forced to take power from incumbent utilities at unreasonable prices.

As a future option, the City may consider financial participation in power supply projects that meet the City's business objectives of renewable energy and/or low cost efficient and reliable resources; however, at this time, R. W. Beck recommends that the City obtain only a distribution utility. Consequently, as mentioned above, we do not recommend acquiring Valmont.

Cost

The City should exclude generation and transmission assets from this municipalization effort due to the cost of acquiring and maintaining these types of assets. Acquisition costs for these assets will likely be high compared to the relative value of the assets, and generation assets, in particular, are particularly capital intensive (and thus would be expensive to maintain).

The transmission system does feed the load within the City, but it is part of an interdependent system that provides for reliability and stability over the entire region. Due to FERC requirements for open access on transmission systems, the City does not need to own transmission to operate a municipal utility. Because of high acquisition costs, and because these assets are not required, the City should not focus in the near term on acquiring existing generation and transmission assets.

Complexity

Another reason why the City should limit its municipalization efforts to the electric distribution system is for simplicity; the start-up and management of the utility will be an organizational challenge without the additional concerns about operating a generation station or coordinating scheduling on a transmission system. Additionally, by not owning generation or transmission, FERC jurisdiction is not an issue, so the Boulder municipal system will be self-regulated (municipal utilities in Colorado are not subject to Colorado Public Utilities Commission regulation).

As the City municipality matures, it may be wise to investigate various options for power supply, including owning generation (such as renewable resources) and limited transmission systems (not necessarily those within the City); however, R. W. Beck recommends that this decision be delayed until the municipal distribution utility is fully functional.

Incomplete Natural Gas Data

The data made available for the natural gas distribution for the City in the annual reports provided by Xcel were incomplete and unreliable. Given the lack of reliable data, R. W. Beck was unable to determine if the physical condition of these assets would provide value to the City. R. W. Beck did determine that a natural gas supplier does own and operate a nearby pipeline that could potentially serve the City's needs. However, it is not clear where the natural gas system crosses back and forth over the City's boundaries; therefore, the City may have difficulty in developing a workable severance plan. If better data and accurate maps were provided to the City,

R. W. Beck would recommend that the effort to acquire the natural gas distribution system be reviewed at that time.

Methodology

R. W. Beck reviewed retail rate scenarios to assess the various net revenue streams (to include capital, reserves and operational cost of running a municipal utility) and determined the resultant cash that would be available for debt service payments. This methodology assumes that the City's average system rate would be equal to Xcel's average system rate. The sum of the principal portion of these debt service payments represents the "value" or "worth" of the utility to the City. Information provided in Xcel's Annual Report for 2003 was reviewed to determine the book value and the replacement costs of the assets (including depreciation) in order to represent Xcel's "value" of the system. The City's "worth" of the system, less expenses associated with the bond issue to finance it, as well as severance and potential stranded costs, was then compared to Xcel's calculated "value" of the system.

Section 2
PHYSICAL REVIEW, SEVERANCE, STRANDED INVESTMENT

To operate as a municipal utility, the City will have to acquire certain existing Xcel assets. This will require the City to segregate the existing system that serves the City from the system that serves the general Boulder area. The cost estimate associated with segregation of the facilities is referred to as the “severance cost.” To determine the severance cost, we conducted a limited field review of the electric distribution system within the City to establish where potential severance issues may exist relative to the system design and the City’s municipal boundaries. Additionally, while we were conducting the field review to investigate severance issues, we also reviewed the physical condition of the system.

For the purposes of this study, severance consists of the physical separation of the Xcel system in such a way that the City and Xcel can each own and operate most of their own sets of facilities. Another type of severance is referred to as “administrative segregation.” In this type of severance, information is shared between the two utilities relative to each customer usage, and in some cases, retail billings of one utility’s customers are provided by the other utility. This type of severance is typically less expensive to implement than “physical” severance, because there is no need to build duplicate facilities and customers are handled on an administrative basis. However, given the potentially contentious nature of this municipalization effort, we did not pursue determining costs associated with an administrative severance approach.

Methodology

Our field review was conducted on April 22 and 23, 2005 by two R. W. Beck field engineers. Because we did not seek authority from Xcel to physically inspect any portion of the systems, our review was limited to what was visible from public access viewpoints. Xcel would not provide a system map; therefore, we utilized a street-level map provided by the City’s geographic information system (“GIS”) department that provided the City’s municipal boundaries. We then located the substations that serve City load (customers within the City’s boundaries) and followed the feeders from the substations to the City boundary. As the feeders were reviewed, our field engineers took note of their physical condition, their relative size (using best judgment), and other matters of interest (i.e. overhead, underground, etc.). This information was transcribed to the GIS map using AutoCad software to produce a crude map of the distribution system.

Our distribution map was utilized by our electrical engineering staff to determine what severance issues may exist and to calculate a severance cost. This review was done at a planning level only, and as mentioned above, was based on information obtained from a limited field review without data from Xcel. Severance issues were identified in areas where the feeder crossed municipal boundaries. For areas where the substation was observed inside the City limits, and served only customers inside the City, no unique severance issues were identified. For areas where the substation was observed to be inside the City limits, and served customers outside the City limits, it was assumed that Xcel would require that the City build a “dedicated” feeder from that substation to those customers (whom would retain Xcel service). For those areas where the substation was observed to be outside the City limits, and had a feeder (or feeders) that served customers inside the City limits, it was assumed that the City would essentially place a meter on the feeder at the point of crossing the City boundaries.

To estimate a cost associated with severance, our electrical engineers assumed that “dedicated” feeders could be built in existing right of ways alongside the existing feeders. Additionally, they assumed that the City would be required to pay for the installation and capital costs of building these feeders in addition to the cost associated with purchasing and installing the required metering equipment.

We identified 11 substations located in the general Boulder area from publicly available sources. However, we were unable to find all 11 substations during our field review. Additionally, we did not investigate every feeder from the substations that were observed in the field, as some substations have multiple feeders and several feeders were difficult to follow without adequate maps from Xcel.

Severance Results

The results of the severance analysis suggest that the City could expect to incur costs of approximately $5 million to physically sever the system from Xcel’s existing distribution system. These costs assumed major reconfiguring of the Boulder Terminal Substation with a combination of underground and overhead lines and facilities, including double circuit configuration, to feeders serving the load to the north and northwest of the City. Any costs associated with new construction to replace overhead facilities with underground facilities, in accordance with City ordinances, have not been estimated and included. In addition, these costs assumed major reconfiguring of the Sunshine Substation with express feeders to serve customers outside of City limits to the west and southwest of the City. Finally, these costs included switchgear additions at 75th and Leggett Substations and new feeders extending overhead with a combination of single and double circuit lines. It should be noted that this severance estimate is based on a preliminary assessment of the configuration of the distribution system in the City without the benefit of information provided by Xcel. Additionally, cost estimates for new feeders were based on a preliminary review and certain assumptions, such as the ability to physically locate them in the necessary location, were made without regard to existing constraints. Therefore, this severance value may increase as a result of additional investigations into the City’s municipalization effort.

Condition Assessment Results

As mentioned above, an additional purpose of the field review was to determine the relative condition of the poles, wires (conductors), and low-end of the substations. In general, the condition of the distribution system that was observed is good to excellent. These are qualitative indicators of visual appearance and not necessarily an indication of useful life of the assets. Several of the utility poles appeared to have been recently tested for integrity. No loose or dangling wires were observed during our review. Much of the downtown area of the City's distribution system has been placed underground and therefore was not observable to our field engineers. However, where it was observable, the systems at the point they go underground were found to be in very good condition. Additionally, there appeared to be significant redundancy and over-design of several portions of the system. Redundancy is important to a distribution system as it can improve system reliability by protecting the system from a total loss of power if one portion is interrupted. Over-design can also assist in reliability, as the system can handle higher fluctuations in load due to increased capacity of certain equipment. However, depending on the design, excessive redundancy and over-design can also increase the cost associated with a system with only marginal benefits to the customers. No design assessment or load flow analysis was conducted as part of this physical review. Additionally, no information was available to us to determine outage rates for the distribution system as a whole.

Sub-Transmission Facilities (115- and 230-kV)

Transmission facilities located within the City are primarily at 115-kV. However, there are some 230-kV facilities that occur within the City as well. We assumed that both 115-kV and 230-kV transmission facilities would remain part of the Xcel system and would not be acquired by the City.

Substation Facilities

There appear to be seven substation facilities located in the City. Leggett Substation, located by Valmont, is lattice steel, high-side construction with metal enclosed outdoor switchgear on the low-side. The other substations are tapered steel, high-side construction with metal enclosed outdoor switchgear on the low-side. The University of Colorado ("CU") campus substation was not located. The 230-kV construction is from Valmont to the 75th Substation and then continues on to the Niwot Substation. The remainder of the transmission in the City appeared to be 115-kV. The distribution circuits exited the switchgear underground to the first distribution poles. The City would need to own a portion of the low-side of each substation in order to operate its distribution system.

Distribution Facilities

The distribution circuits were assumed to be 13-kV, 3-phase with single-phase taps. Most of the distribution circuits observed were double-circuit vertical construction with line post insulators on wood poles. Some of the distribution circuits out of the Terminal Substation were tapered steel pole construction. There was also some cross-arm construction in some of the areas we reviewed.

All of the overhead construction appeared to be in very good condition with signs of continuing maintenance. The underground distribution facilities were noted on the City map but the locations of the distribution transformers were not reviewed.

Stranded Investment

As mentioned in Section 1 of this Study, the City's acquisition of Xcel's distribution assets might be argued to leave Xcel with stranded investment. As part of the data request sent to Xcel on March 30, 2005**,** the City requested that Xcel provide a determination of the cost of its stranded investment, in accordance with FERC regulations. However, Xcel did not reply to this portion of the City's data request.

This section provides a description of our approach to the calculation of the stranded investment costs. As noted previously, the FERC will likely determine the issue of stranded costs. The City may argue that no stranded costs exist in this situation. Therefore, R. W. Beck's opinion should be considered a conservative and preliminary approach to this issue.

FERC Stranded Cost

FERC Order No. 888, in addition to its Opinion No. 438 in the City of Las Cruces v. El Paso Electric Company, included an approach to determining stranded investments that is summarized as follows:

SCO = (RSE – CMVE) x L

Where:

SCO = Departing Customers Stranded Cost Obligation

RSE = Revenue Stream Estimate that the utility could have expected to recover from the departing customer if open access transmission had not been available

CMVE = Competitive Market Value Estimate of the capacity and associated energy released by the departing customer

L = Length of time the utility could have reasonably expected to continue to serve the departing customer if open access had not been available.

The terms incorporated above are open to interpretation and quantification. Therefore, the SCO would ultimately need to be determined through a stranded cost proceeding. The following describes the development of a stranded cost estimate, which R. W. Beck believes to be generally consistent with FERC precedent.

- R. W. Beck's understanding of the RSE value is that it is the difference between the average monthly operating revenue, less transmission revenue and distribution revenue.
- R. W. Beck's understanding of the CMVE is that it is based on the total retail load for the City multiplied by the estimate for the price of power.

The difference in the monthly RSE and the monthly CMVE (the annual load divided by 12 months multiplied by the price for power above) represents the monthly stranded cost calculation. If the market price for power (and thus the CMVE) grows at a rate faster than the RSE, there could be "negative" stranded costs, or stranded "benefits." This would suggest that the cost of production associated with the utility operating revenue are less than what the market is paying for power (for example, if the utility had very low cost power relative to the regional market). Under these scenarios, the incumbent utility could expect to earn more from the market than from serving the customers and there would be no stranded investment.

Another important determinant of stranded costs is the "L" value, which represents the length of time the utility could have reasonably expected to continue to serve the customer. Investor-owned utilities often will claim that their planning horizon is for 10 to 15 years. However, in the case of the City, it could be expected that the utility should not expect to serve the citizens after expiration of the franchise agreement (2010). The calculation of the "L" term is subject to legal review and obviously drives the calculation of stranded costs.

Example Calculation

For illustrative purposes, we have calculated a cost associated with stranded investment, based on public information and assumptions. It is important to note that this analysis does not imply that stranded investment exists. However, for the purposes of our preliminary analysis, we have included an estimation of costs associated with stranded investment.

For 2003, Xcel's reported annual operating revenue for the City was approximately $85.5 million. This amount divided by 12 months results in an average monthly operating revenue value of approximately $7.1 million. Annual transmission and distribution revenues were estimated to be approximately $1.0 million per month, based on Xcel's rate case, which results in a monthly RSE value of approximately $6 million. Assuming a value of approximately $56 per MWh for market price of power (at the wholesale level), results in an annual stranded investment cost of approximately $6.5 million. Applying this cost to a 5-year period (the time period between the date of this Study and the end of the current franchise agreement), and discounting the value with a discount rate of 9.5 percent results in a value of approximately $20 million. The actual value of "L" will be zero if the City's acquisition is concurrent with the expiration of the current franchise agreement.

It is important to realize that the effect of stranded investment is primarily a function of the production cost of the utility compared to the "market" and the length of time (the "L" value). If the production cost of the utility is equal (or very similar) to the market, the costs of stranded investment are reduced. Additionally, if the “L” value is reduced (and depending on the legal argument, it could be zero), the costs are also reduced.

For the purposes of our analysis, we have computed assumed a preliminary value of approximately $20 million. However, if the difference between the production costs and market costs were different than those assumed, the stranded cost could be significantly higher or lower. We recognize, however, that the length of time Xcel would reasonably expect to serve the City may well be limited to the term of the existing franchise agreement.

Section 3
CASH FLOW ANALYSIS

Introduction

A cash flow analysis was prepared to model the projected operations of a municipal electric distribution utility. The model projects utility revenues, operation and maintenance expenses, capital requirements and reserve levels. After these cash obligations have been met, the model calculates any remaining free cash flows ("FCF") available for debt service payments. The present value of the cash flows represents the maximum amount the City could pay for Xcel's distribution assets and still meet all the financial goals and objectives of a municipal utility.

FCF is a function of rate revenues and operating costs. The analysis is a top down approach in the sense that rates are not set on a cost plus return basis but rather are benchmarked against a projection of Xcel's average system retail rate. This modeling approach allows the City to evaluate various competitive rate scenarios and the corresponding purchase price of the assets. Additionally, given a particular competitive rate scenario, the impact of alternative power supply options on the purchase price, including renewable options available to the City can be determined. For the purposes of this Study, alternative power supply options have not been evaluated.

Model Components

Model components and logic flow results are shown in Figure 3-1.

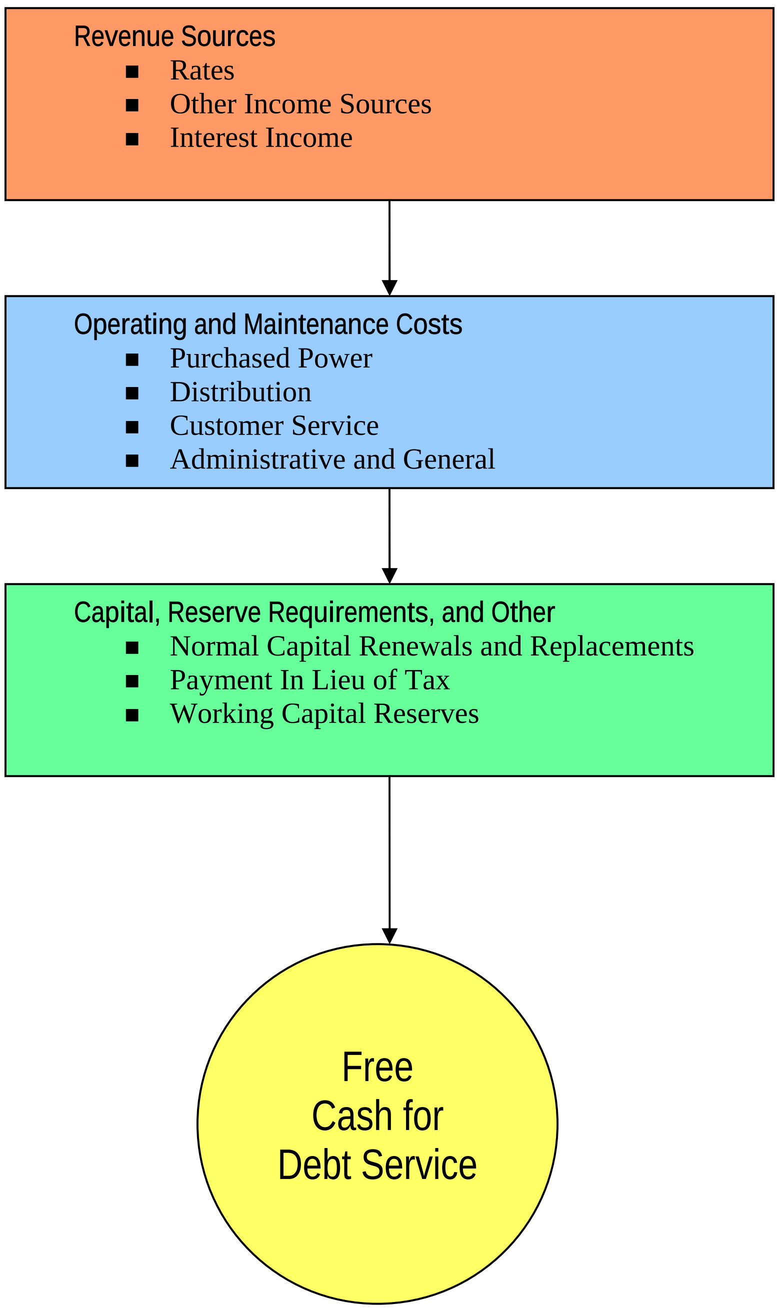

Figure 3-1: Free Cash Flow Model

Major revenue and cost components (or drivers) of the model having significant impact on FCF are:

- Rate Revenues
- Purchased Power Costs
- Operation and Maintenance Costs
- Payment to the City In Lieu of Tax
- On-going Capital Requirements
- Cash Reserves Requirements and Financing Assumptions

A discussion of each of these major items follows.

Rate Revenues

Rate revenue is the product of customer load and average system rates. Since the City's average system rate is benchmarked against Xcel's average system rate, the two important components in the model's rate revenue projection become the City's retail load forecast and a projection of Xcel's retail rates. As stated earlier in this Study, this analysis benchmarks the rate structure of the City's municipal electric utility against Xcel's average system retail rate. This approach allows the City, from a competitive perspective, to value the utility under different rate scenarios. In this Study, we examined the impact on system valuation under three scenarios. These scenarios calculated system valuation if City retail rates were set at levels 95 percent, 100 percent and 105 percent of Xcel's average system rate.

Load Forecast

A load forecast was developed for the City, which assumed the following:

- As defined in the Study, load includes only those customers within the current municipal City boundaries. Customers in Boulder County were not considered.
- The CU load is included within the City boundaries and this load will be included in future City load projections.
- City growth and development policies as currently implemented will not materially change over the study period.
- Observed historical growth patterns over the 5-year period 2000-2005 will continue into the future.

The forecasted City load compared to Xcel's system load is shown in Figure 3-2.

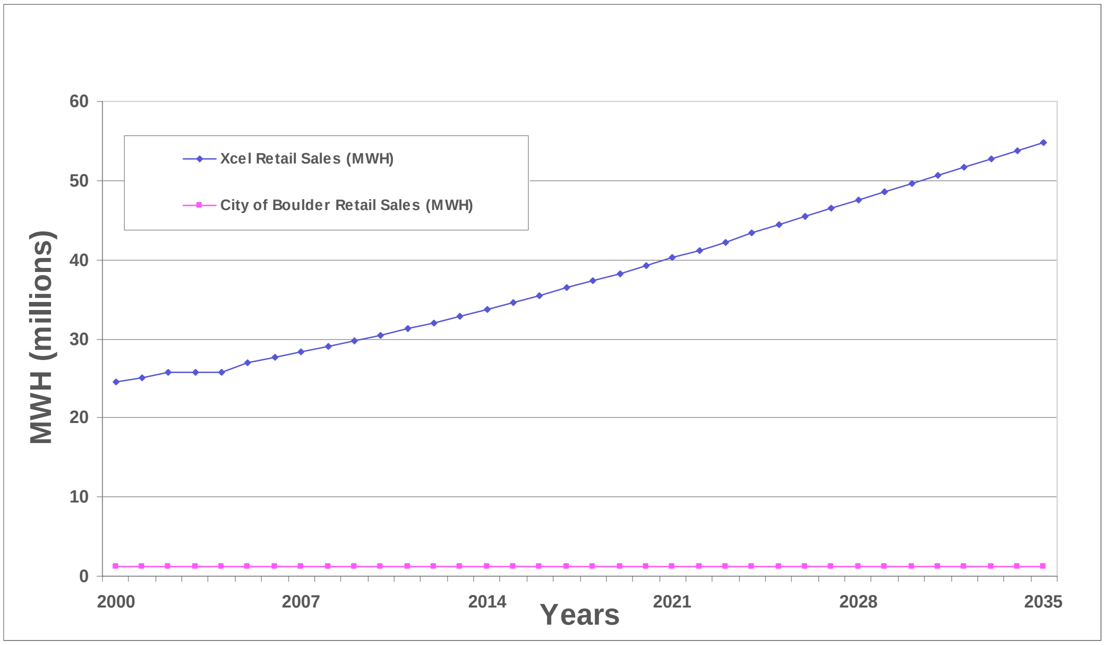

Figure 3-2: Projected Retail Sales

The City's load is projected to grow at a very minimal level over the next 30 years, less than 0.25 percent annually. This result is due to the fact that the City is largely developed. Growth rates are significantly lower than those projected by Xcel on a system-wide basis. Additionally, data from Xcel provided on July 15, 2005 indicates higher growth rates for the City than historically determined. However, without validating these growth rates, we have not incorporated them into our analysis. In general, higher growth rates would result in higher FCF, thus increasing the "worth" of the assets. This issue should be further investigated if the City chooses to move forward with its municipalization effort. Xcel's load growth estimates were taken from Xcel's 2003 Least Cost Resource Plan – Base Case ("LCRP"). As shown in Figure 3-2, the City's load is a small component of the overall Xcel system.

Xcel Average Retail Rate Forecast

A projection of Xcel's retail rates was developed by creating a revenue requirement for the Xcel retail system. A revenue requirement is a bottom up approach to rate setting. Operating costs, depreciation expense, taxes, and return are calculated resulting in a revenue requirement for rate setting purposes. This analysis is shown in detail in Figure 3-4. As shown in this figure, Xcel's rates are based on the following components:

- Operation and Maintenance Costs
    - Production Costs
    - Purchased Power Costs
    - Transmission Costs

- Distribution Costs
- Customer Service Costs
- Administration and General Costs

- Depreciation Expense
- Taxes
- Return on Rate Base

The above costs are netted against other non-rate sources of revenue such as interest income to yield a revenue requirement for retail rate setting. One component, return on rate base, required an examination of Xcel's historical realized returns. A percentage return was calculated by comparing actual reported return to utility net plant in service, a proxy for rate base. Rate base is generally defined as Xcel's net plant in service (gross plant less accumulated depreciation) plus working capital, provision for deferred income taxes and other miscellaneous items. The allowed percentage return multiplied by rate base yields the return component of the Xcel revenue requirement.

Key drivers impacting the Xcel retail rate projection were as follows:

Load Growth

Load growth on the Xcel system was estimated based on Xcel's 2003 LCRP. This load projection is graphically shown in Figure 3-2.

Production Cost

For the first 10 years of the study period, Xcel's production costs were projected based on the resource plan as contained in the LCRP. Unit capacity factors as provided by Xcel in the LCRP (provided through 2033) were applied to R. W. Beck's gas and coal fuel forecasts and unit specific cost data. Beyond the 10-year period, the LCRP did not provide any information with respect to Xcel's long-term resource mix. In the absence of this information, we developed a resource plan to project Xcel's production cost over the remaining years of the study period. The projection was completed by assuming capacity shortfalls were met with new resource additions. For this analysis, we estimated that Xcel would have to install 5,850 MWs of additional capacity over the 2019–2035 time period. For modeling purposes, we assume new capacity would be met with a combination of coal fired (4,500 MW) and renewable (wind) resources (1,350 MW). This mix is consistent with existing Xcel policies and state regulations, specifically the Renewable Portfolio Standard. Within the LCRP 10-year planning horizon, we included the anticipated 750 MW coal resource at Comanche Peak that is expected to be operational in 2009.

Once new resources were added to the production cost model on an annual basis, total production costs were calculated for the period 2005-2035. Units were dispatched to Xcel's total load requirements including sales for resale. Production costs attributable to retail customers were estimated by assuming a variable cost plus margin pricing mechanism for Xcel's sales for resale. Sales for resale revenues were netted against total system revenue requirements resulting in net system revenue requirements attributable to retail sales.

A summary of this analysis with projected power costs is shown in Figure 3-3.

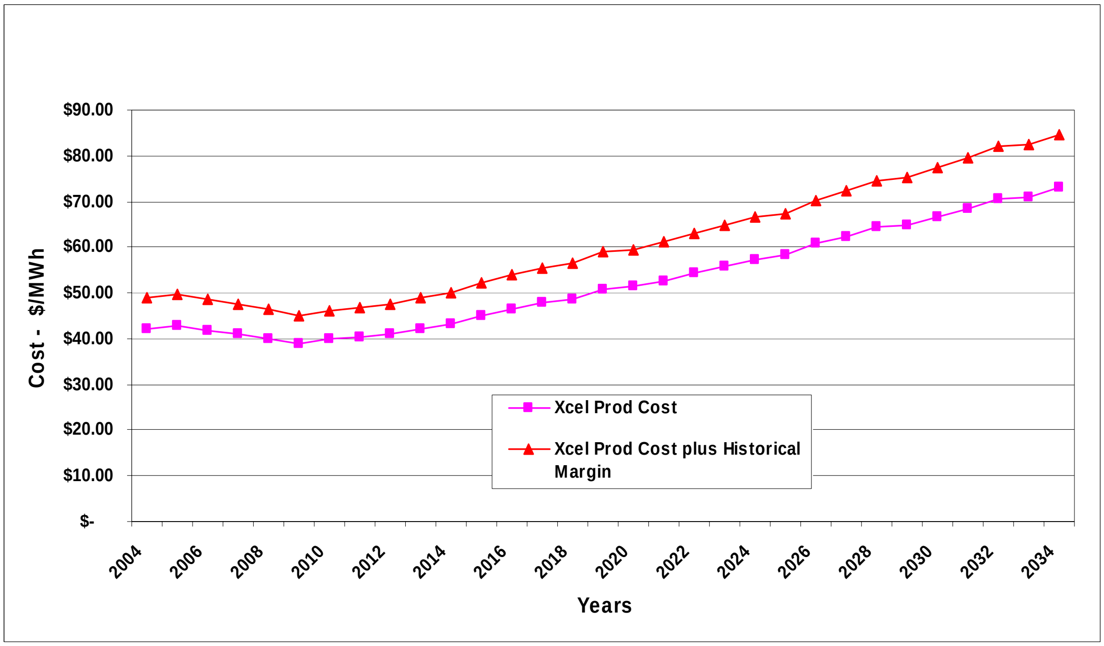

Figure 3-3: Projected Power Costs

Two power cost projections are shown in Figure 3-3. The lower projection represents Xcel's projected power costs over the period. The higher projection represents our estimates of bilateral all-requirements power supply contracts.

Other Operation and Maintenance Costs

Transmission, distribution, customer service and administration, and general expenses were projected based on a combined annual escalation factor that included inflation as represented by the Gross Domestic Product ("GDP") deflator and load growth. This methodology recognizes that operation and maintenance costs are a function of inflation and load growth, particularly as service territories are expanded via new development.

Depreciation and Amortization Expense

Using projected gross and net plant investment as described below, depreciation expenses were calculated.

Taxes

The projection of tax liability is a very complex calculation for an Investor Owned Utility such as Xcel as there are various mechanisms for corporations to lower its near-term tax liability. Additionally, one can be certain that changes to the current Federal and State tax codes will occur over the forecast period. With this in mind, we forecasted Xcel's Federal, State, and Local income, property and payroll tax expense by examining the historical relationship between Xcel's overall annual tax expense and return on rate base. The results of this analysis indicate that Xcel's historical effective tax rate is 14.5 percent of actual return on rate base. Therefore, we projected Xcel's future tax liability at 14.5 percent of return on rate base.

Return on Rate Base

Return on rate base was calculated by applying Xcel's historical annual average return on rate base to a future projection of rate base as described below. As a proxy for rate base, net plant in service was used in the analysis. On a historical basis, Xcel's return as a percentage of net plant in service is 10.23 percent.

System Capitalization (Rate Base)

System capitalization considers Xcel's reinvestment into the existing system, as well as capital additions necessary to meet load growth. The level of this ongoing capital investment was determined by examining the historical relationship between capital additions and retail load over the 11-year period of 1994-2004. This analysis examined the historical relationship of gross plant and net plant-in-service. We found the correlation between investment as measured by gross plant-in-service and net plant-in-service to be very high. A long-run forecast was developed for plant investment using these correlations.

Other Income Sources

Other income represents revenue from non-retail, rate-related sources. Typically, they include interest income, service and connection fees, late charges, and revenue from wholesale sales. In the rate setting process, other income sources are netted against the total system revenue requirements. The resulting net system revenue requirement represents costs that must be recovered from rates. Other income related to interest income, service and connection fees, late charges, etc. was estimated on a $ per MWh basis using information available in the recently approved Xcel electric system rate case. This type of income was estimated to be $0.60 per MWh sold.

With respect to wholesale sales, we relied upon our production cost model to estimate MWh sales and related revenue in this area. Revenues were estimated based on market price projections and Xcel's historical wholesale sales margins as reported in FERC Form 1 documents. It should be noted, however, that FERC Form 1 data, while required by FERC, are highly suspect as these data are rarely verified and can be open to discretion by the filer. These data should not be relied upon solely to determine whether the City should move forward with its municipalization effort.

The projected Xcel net revenue requirement consists of those items described above. Net revenue requirements were divided into total system retail load as reported in the Integrated Resource Plan ("IRP"). Figure 3-4 shows the projected Xcel average system retail rate.

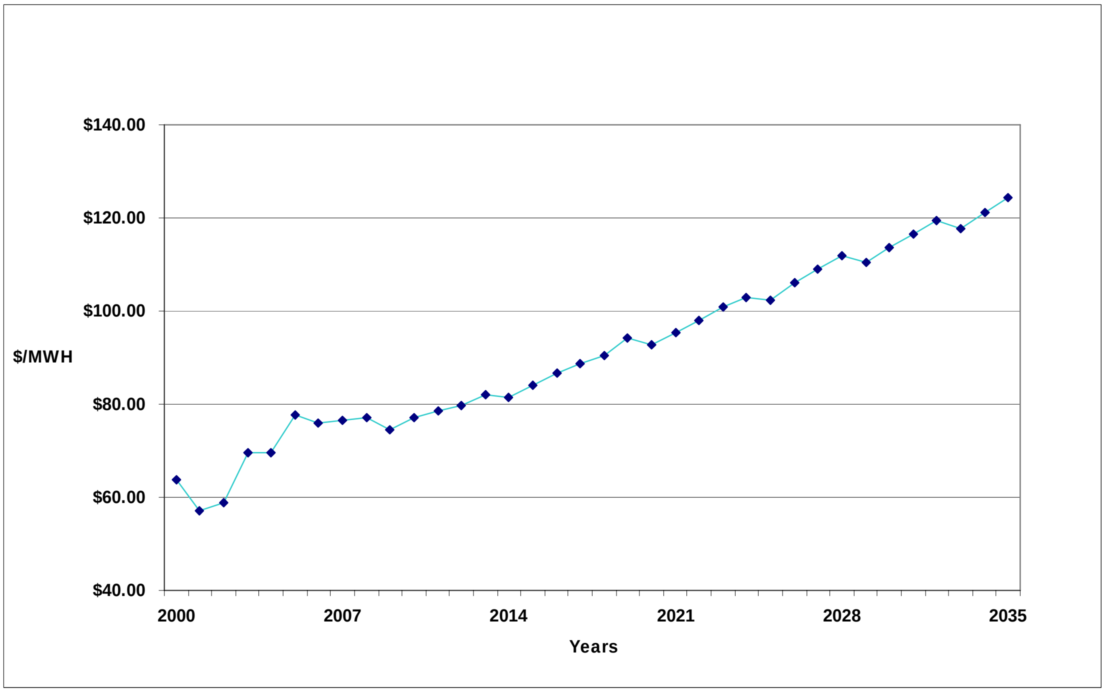

Figure 3-4: Average System Rate ($/MWh)

The average system rate represents a blended dollar per MWh value that must then be recovered from residential, small commercial, large commercial and industrial customers. Typically, the costs of serving residential and small commercial customers are higher than serving large industrial (high load factor) loads. Correspondingly, rates are higher for residential customers than for large industrial customers. Future analyses should examine load and revenue information specific to the City to determine if a customer mix adjustment is warranted. For this analysis, no adjustment has been made.

Purchased Power Costs

The cash flow model assumes that the City will purchase all power to meet load requirements. We have assumed that the City will enter into long-term all-requirements power supply contracts with any number of power suppliers in eastern Colorado. An all-requirements power supply contract is a contract that would provide capacity and energy to meet the total system requirements of the Boulder municipal utility. In contrast to the utility buying blocks of power from various suppliers, an all-requirements contract transfers management of the power supply, on an hourly or incremental basis, from the utility to the all-requirements provider. However, there is a cost associated with this service.

Potential full requirements or partial requirements suppliers include Xcel, Tri-State Generation and Transmission Association, Platte River Power Authority, Black Hills Power, Municipal Energy Authority of Nebraska, the city of Colorado Springs and a variety of Independent Power Producers. Accurate market pricing information for these types of contracts can only be determined through a power supply solicitation process. In the absence of such information, we have estimated prices that may be realized by the City on a bilateral contractual basis. We would expect that this type of pricing be less than on-peak spot market prices that may be observed in the current market. We expect this result because all-requirements customers require a significant amount of power to be supplied during off-peak periods at a lower cost. The blended cost of an all-requirements customer should be less than on-peak spot market prices.

R. W. Beck has forecasted all-requirements pricing by projecting Xcels' production operating costs plus a margin. The margin was determined by evaluating historical mark-ups on sales for resale customers as reported in the FERC Form 1. Based on our review of this information, we have assumed a 16 percent mark-up on Xcel's projected power costs.

Figure 3-5 shows a projection of bilateral all-requirements contracts over the study period.

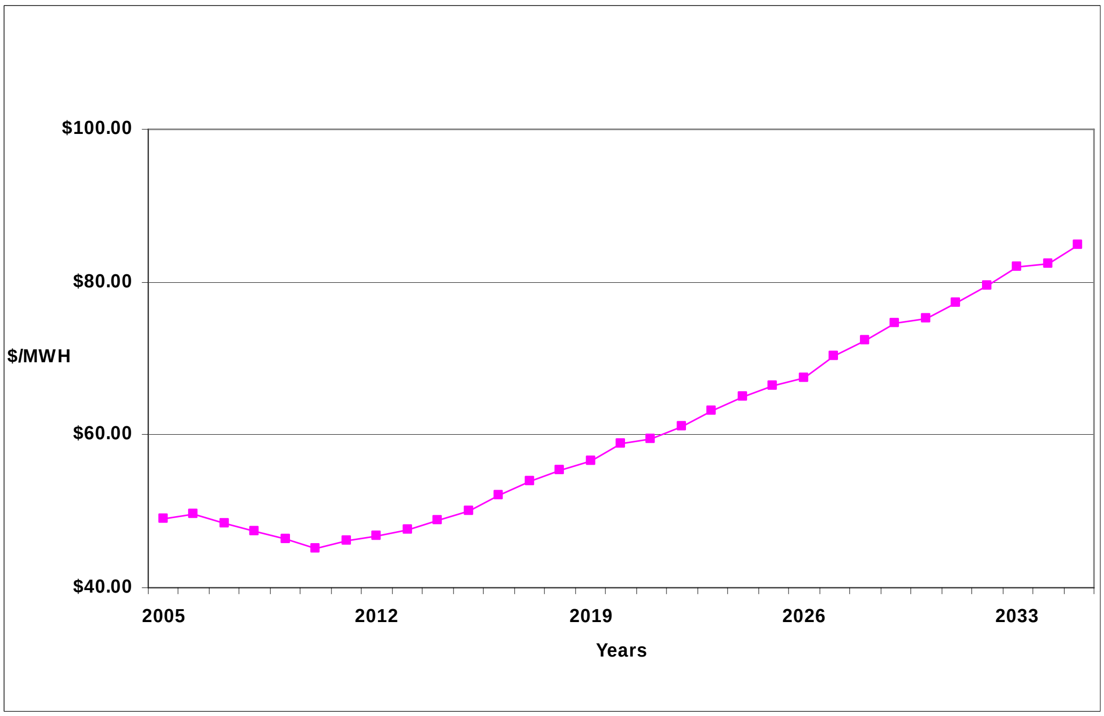

Figure 3-5 Bilateral All-Requirements Contract Rate Estimate

Transmission Issues

The delivery of electric power to the City is dependent upon regional and local transmission systems. On a regional level, the state of Colorado is a part of a large-scale, integrated transmission system that encompasses the western U.S., extending from California to western Nebraska. The overarching coordination of this network is conducted through the Western Electricity Coordinating Council ("WECC"). There are also a small number of locations where the WECC is connected to neighboring systems (e.g. the Midwest Reliability Organization or Southwest Power Pool) through direct current ("DC") ties. The DC ties that could potentially influence the delivery of electric energy in Colorado are located in Sidney, Nebraska and Stegall, Wyoming.

Due in part to the sparseness of Colorado's population, there are relatively few transmission lines that interconnect Colorado to neighboring states. Consequently, transmission bottlenecks (commonly referred to as "TOTs") exist and potentially constrain the interstate market for electric power, including:

- TOT7: Between Colorado and Wyoming
- TOT3: Between northeast Colorado and Wyoming/Nebraska
- TOT5: Between central Colorado and northwestern Colorado
- TOT2: Between southwestern Colorado and New Mexico

The capacity of each TOT is routinely analyzed by the affected utilities and, in some cases, may reach its transmission limitations.

In addition to these regional issues, the delivery of power to the City is also affected by the local transmission system. The City's proximity to mountainous terrain on the west and sparsely populated areas to the north and south cause the local transmission system to primarily come from the southeast side. There are relatively few transmission lines that serve the City and such lines are owned by Xcel. The lack of alternate, local, transmission paths into the City could impede local competition or markets for power.

However, FERC Order 888 requires utilities to provide open access to their transmission systems. Further investigation of this issue, and how it relates to the City's potential municipalization effort, is warranted. This investigation could include initial load-flow simulation studies to determine the impacts, if any, of the City securing its power needs via an alternative supplier to Xcel, as well as legal review of FERC Order 888.

Additionally, the Wyoming Infrastructure Authority and the Western Area Power Administration have recently announced a project to upgrade the TOT3 transmission line. According to the American Wind Energy Association, this upgrade is an important project that will enable wind generation from Wyoming to reach the Colorado market. Additionally, the Western Business Roundtable praised the project stating that it would bring low-cost coal and wind power to the Colorado Front Range.

Operation and Maintenance Expense

Operation and maintenance expenses were projected for the City system using available cost benchmarking data from the American Public Power Association ("APPA"). On an annual basis, APPA provides "APPA Selected Financial and Operating Ratios of Public Power Systems," which statistically evaluates various performance metrics for public power systems. In our analyses, we used APPA statistics for distribution operation and maintenance expense, customer service and collection expense and administration and general expense. Applied ratios were pertinent to municipal utilities in the western United States with customers ranging from 20,000-50,000. The ratios are on a dollar per customer basis and represents mean results of the participating utilities. The ratios for distribution operation and maintenance expense, customer accounting, service and sales expense, and administration and general expense are summarized in Table 3-1.

Table 3-1
APPA Selected Financial and Operating Ratios for Public Power Systems - 2003 Data
(Published May 2005)

Expense Item	Sub Group	Utilities Sampled	Mean Weighted Value per Customer
Distribution O&M	Western States	20	$141
Customer Accounting Service and Sales Expense	Western States	20	$86
Administration and General Expense	Western States	20	$117

Payments to the City in Lieu of Taxes

The analysis assumes that the municipal utility would pay the City on an annual basis a payment in lieu of tax based on 3 percent of gross revenues. This payment level is approximately equivalent to the current franchise fees and property taxes paid by Xcel to the City.

On-going Capital Requirements

As described earlier in this Study, the City will purchase only distribution utility assets. Additionally, the City's load growth is expected to be minimal over the study period. Therefore, future capital requirements were estimated to be equal to annual depreciation rates of the utility valued on a reproduction cost new less depreciation ("RCNLD") basis. This methodology assures that the City will have adequate cash to renew and replace the existing system over the long run.

Cash Reserves and Financing Assumptions

The City's municipal electric utility must operate within certain financial guidelines in order to preserve and maintain the integrity of the system over the long run. Based on our experience working for other municipal utilities across the country, we developed the following cash reserve requirements and financial objectives.

- System rates must generate a minimum debt service coverage ratio of 2.0.
- The utility shall maintain the following cash reserves:
  - Debt Service Reserve – This reserve sets aside one year's debt service payment as a guarantee to lenders that sufficient cash is available to make payments within a 12-month period. This reserve is required as long as the City's municipal utilities have outstanding debt service obligations. The reserve is generally set at the maximum future debt service payment.

- Working Capital Reserve – The utility, at all times, must have cash reserves equivalent to 1/8th of total operation, maintenance, and normal capital requirements of the utility.

Our analysis assumes that the initial funding of these reserves are borrowed as a part of the initial debt service offering related to the utility acquisition. Future funding requirements are generated from rate revenues. Revenue bonds would be issued to support 100 percent of the anticipated acquisition price, reserve requirements, and any other costs of issuance. Bonds are assumed to be issued over a 30-year period at a 6 percent average coupon rate.

Power Market Issues

Wholesale competition in the Colorado market is a key element to a successful municipal electric distribution utility. If Xcel continues to dominate the market, and therefore the wholesale prices, the cost of purchasing wholesale power may result in higher than expected rates. Two new proposed transmission developments in northern and eastern Colorado will contribute to higher levels of competition in the Colorado wholesale power market: (1) increasing transmission capability on the TOT-3 line from Wyoming, and (2) new transmission built in association with the development of a new coal plant in Kansas (all power is designated for Colorado). Addition of these new capabilities will allow access to additional coal and wind resources in Eastern Colorado and Wyoming.

Section 4
PURCHASE PRICE ANALYSIS

Introduction

This section of our Study discusses the worth of the assets to the City under various valuation perspectives. We will compare book value of the assets as reported by Xcel (original cost less depreciation or "OCLD") and reproduction value of the system (reproduction cost new less depreciation or "RCNLD") with the top-down cash flow analysis. The results of our studies are described below.

Cost Approach

The cost approach is a commonly used term for evaluating the assets valued by looking at OCLD (or book value) and RCNLD.

OCLD is defined as the original cost of the property when it was first put into service, less accrued depreciation. The OCLD value is equal to the net book value of the property, which is generally equivalent to the rate base value of the property for ratemaking purposes. RCNLD is defined as the cost of constructing an exact replica of the property at current prices, with the same or closely related materials, less accrued depreciation. The RCNLD and OCLD values tend to set the upper and lower limits, respectively, on the range of fair market value for electric system property.

To determine an original cost less depreciation, R. W. Beck utilized the 2004 plant investment value provided in Xcel's 2004 Annual Report for the City. R. W. Beck utilized the values for the "Local System." A request for a description of the local system compared to the integrated system was not granted by Xcel. It should be noted that the plant investment reported in Xcel's report appears to be an allocation of total system investment to the customers in the City, which could be substantially different than the original cost of the actual facilities in Boulder based on an inventory. Additionally, the 2004 values appear to include a large allocation of Common Plant from the Integrated System to the Local System. This results in higher OCLD and RCNLD values for 2005. This shift appears to be unusual and warrants further review. For the purpose of this Study, we have utilized the values provided by Xcel in their 2004 Annual Report to the City.

The 2004 plant investment was reduced by the estimated accumulated depreciation (based on actual allocated accumulation and the depreciation reserve ratio in Xcel's FERC Form 1 report). This results in a 2004 OCLD value. This value was then increased by utilizing a cost adjustment index to reflect 2005 values. The RCNLD was calculated based on the 2004 OCLD and the estimated average system age (using an industry index). This analysis assumes the average ages of the facilities in Boulder are the same as the system average age, which should be investigated.

The results of these analyses are summarized in Table 4-1.

Table 4-1
Estimates for OCLD/RCNLD

	Plant Investment	Net Plant (OCLD)	2005 Cost-Adjusted OCLD	2005 RCNLD
Local System (2003)				
Distribution lines and facilities	$97,932,000	$69,704,458	$77,747,280	$103,458,979
Common Property	4,978,872	3,935,170	4,283,321	4,626,483
Total Plant In Service	$102,910,872	$73,639,628	$82,030,601	$108,085,462
Local System (2004)				
Distribution lines and facilities	$104,795,000	$75,141,314	$82,589,724	$111,528,643
Common Property	12,467,000	9,901,350	10,642,291	11,640,776
Total Plant In Service	$117,262,000	$85,042,664	$93,232,015	$123,169,419

Note: The allocation of General and Common Plant appears to have shifted significantly from the Integrated System to the Local System in the 2004 Annual Report for the City. This impacts the book value of the Local System. In our view, this appears unusual and further investigation of this issue is warranted. For the purposes of this Study (and analyses), we have utilized the 2004 values provided by Xcel in their Annual Report to the City.

Cash Flow Analysis

Using the models and related assumptions as described in Section 3, we developed purchase price scenarios under three different rate assumptions to illustrate the sensitivity of worth to rate levels. These scenarios are as follows:

- Base Case – Assumes that the City’s average retail rate will be equal to Xcel’s average retail rate over the study period.
- Below Xcel Case – Assumes that the City’s average retail rate will be 5 percent less than Xcel’s average retail rate for the first 10 years of the study period.
- Above Xcel Case – Assumes that the City’s average retail rate will be 5 percent greater than Xcel’s average retail rate for the first 10 years of the study period.

The results of these case flow analyses are summarized in Table 4-2 below.

Table 4-2
Free Cash Flow Analysis
Worth Under Various Scenarios

Case	Worth Excluding Severance and Stranded Investment	Worth Including Severance and Stranded Investment
Base Case	$105.9 Million	$80.5 Million
Below Xcel Case	$75.2 Million	$49.9 Million
Above Xcel Case	$136.5 Million	$111.1 Million

System value ranges from $49.9 million to $136.5 million depending on retail rate levels and assumptions pertaining to severance and stranded investment. Variations from the Xcel average system rate were only considered during the first 10 years of the 30-year cash flow. After this 10-year period, rates were assumed to match the projected Xcel average system rate. A 5 percent change in the average system rates results in a 25 percent change in the amount the City would be willing to pay Xcel for these assets. Retail rates are a significant assumption impacting system worth and are driven primarily by power supply costs. Retail rates are identified as a critical issue in this Study.

Another important assumption impacting system worth is power supply costs. Table 4-3 shows the impact on worth under the base case assuming that power costs were slightly higher or lower than those projected.

Table 4-3
Free Cash Flow Analysis
Base Case Worth Under Purchase Power Variations

Case Variation	Worth Excluding Severance and Stranded Investment	% Change
Base Case (16% markup)	$105.9 Million	N/A
Scenario 1 - Base Case w/ 15% markup	$112.6 Million	+ 6.3%
Scenario 2 - Base Case w/ 17% markup	$99.2 Million	- 6.3%

As indicated in Table 4-3, a 1 percent change in markup of power supply costs results in an approximate 6 percent change in system worth. Therefore, power supply costs could potentially be a critical issue for this municipalization effort. For the purposes of this Study, the costs associated with alternative energy power supply options have not been evaluated.

Cash Flow Analysis Compared to Cost Approach

Cash flow scenarios, where rates were set at or above the Xcel average system rate, severance, and stranded investment costs, were taken into consideration. Power costs were at or below those contained in our base case scenario and indicated that the worth of distribution assets to the City exceeded OCLD.

When assuming no stranded investment and minimal severance costs, with rates set at the Xcel average system rates, the worth of the system to the City fell between OCLD and RCNLD. When rates are set 5 percent above the Xcel average system rate, the worth exceeded the RCNLD.

Section 5
CONCLUSIONS AND ACTION ITEMS

Based on the analyses described herein, we developed the following conclusions and recommendations for the City's consideration.

Conclusions

The financial analyses conducted for this Preliminary Feasibility Study suggests that there is a reasonable expectation that the City could acquire the Xcel distribution facilities within the City for an amount between the estimated book value of the assets (approximately $93 million) and their estimated replacement value (approximately $123 million). This analysis assumes that the City's average retail rate will be equivalent to Xcel's forecasted average retail rate during the study period. R. W. Beck's analysis is predicated on several issues related to the market price for power, including availability and cost, and costs associated with municipalization, including stranded investment and severance.

The purpose of this Study was to identify significant issues that would preclude the City from moving forward with its municipalization analysis. The results did not identify any such significant issues. R. W. Beck identified specific technical, economic, legal and political issues, as noted below, that warrant further review by the City to determine if municipalization should be pursued.

Length of Time to Achieve

The City can expect Xcel to vigorously resist any attempt to acquire its facilities to establish a municipal electric utility. Based upon R. W. Beck's experience in other municipalization efforts, the City can expect to be engaged in legal battles before the Colorado Public Utilities Commission ("CPUC") and the FERC, as well as court proceedings challenging legal authority for acquiring the operating utility and the price it would have to pay for the facilities. Establishing legal title to the facilities will likely take up to five years to achieve and will be costly in terms of outside legal, engineering and financial experts.

Xcel's budget to oppose the City's efforts is effectively unlimited. The City will have to seriously consider whether it wants to engage in a long, costly fight with Xcel to achieve the municipal utility.

Action Items

Before the City can determine whether the implementation of an operating electric utility should be accomplished, it will need additional definition of the associated costs. At a minimum, the action items that will need to be addressed are discussed briefly below. It is estimated that these items could be completed within one year and could be accomplished prior to municipalization, if so desired.

System Inventory

A field inventory of facilities within the City should be prepared. This effort could be streamlined based upon access to, and quality of, Xcel's records. However, given the lack of cooperation in the past, it is likely that this inventory would need to be done independent of Xcel. This inventory could be done in phased approach. A phased approach would incrementally increase in detail so that the determination of the valuation of the assets could be done incrementally as well. This valuation would need to be included into a traditional "bottom-up" calculation to determine the estimated rates for the City compared to rates for continued operation by Xcel. A system inventory would provide a better basis for calculating OCLD/RCNLD as well. If the City proceeds with municipalization, this system inventory should be completed in a 2006-2007 timeframe.

Severance Design

A detailed design and physical severance plan will need to be developed in order to gain confidence in the costs of separating the facilities within the City from the remaining Xcel system. As mentioned in Section 2 of this Study, our estimates of severance were done from a limited field review with limited access to data. This design plan would provide the basis for a better determination of severance costs to be included in additional financial analysis.

Power Supply Proposals

As part of the Study, a few potential suppliers were informally contacted; however, given the size of the load, there was not a tremendous amount of interest (as not many parties contacted had extra capacity). The City should further investigate potential wholesale power suppliers if it decides to move forward with its municipalization effort. At some point in the future, a formal request for proposal ("RFP") will need to be developed, issued, and bids received and evaluated in order to firm up the municipal power supply costs before any final decision to municipalize is made. This effort should be initiated in 2006 if the City decides to move forward with municipalization.

Investigate FERC Stranded Cost Ruling

The City should investigate the costs and benefits of a stranded cost proceeding at FERC in connection with a request for wholesale transmission service to the municipal utility. This proceeding needs to take place at some point in the future if the City decides to acquire the system and will better identify whether stranded costs exist, and if so, the amount to which the City will be exposed if it decides to operate its municipal utility. R. W. Beck recommends that the City initiate this effort in 2006 if it decides to move forward with municipalization.

Investigate Boulder Load Profile / Rates

The City should investigate its load profile and related rates. The analysis conducted herein is based on information obtained from Xcel's annual reports and other public information. Therefore, several assumptions regarding the load and load profile (how the load varies over time) were made. This information would be necessary to conduct a rate comparison analysis ("bottom up") and would be helpful to better define the potential retail rates and their associated revenues to the City.

Investigate Renewable Resource Purchase Options

If the City is interested in pursuing renewable resources for generation, there are alternatives that exist other than becoming a municipal utility. Currently, there are programs, such as WindSource (which is currently utilized by Boulder citizens), that enables entities to pay for wind generation resources via Xcel's retail rate program. Alternatively, the City could explore the option of partnering with Xcel, or some other entity to provide renewable generation that could displace a portion of its fossil-based generation. The City, as an entity, has the right to build and develop power generation for its own municipal use or to sell back to Xcel. However, the City does not have the right to resell energy to its citizens using Xcel's distribution system. Reselling renewable energy to its citizens is not likely possible within the confines of the existing franchise (with Xcel's distribution system); however, it could be the basis for negotiations with Xcel on a new franchise. Alternatively, if Xcel does not wish to partner with the City, it could give the City further leverage in exploring its municipalization effort.

The following is a review of several renewable technologies that may be considered: biomass, geothermal, wind, and solar. In addition, the review discusses fuel cell technology which many consider being an environmentally "clean" technology similar to renewable technologies. For fuel cells to be truly renewable, the hydrogen fuel must be obtained from renewable resources. Following is a brief description of each technology and the advantages and disadvantages of each. A cost overview is located at the end of the section.

Biomass

Biomass power is produced by using plant materials and animal by-products as fuel. Methods include co-firing, conventional steam boiler, gasification, and anaerobic digestion. Biomass power plants are usually located less than 100 miles from the fuel source to reduce fuel transportation costs. The U.S. biomass industry is mainly located in the Northeast, Southeast, and West Coast regions.

Advantages:

- Carbon neutral – the amount of carbon dioxide released during combustion is approximately equal to the amount of carbon dioxide consumed over the plants life
- Waste management – often biomass plants use industrial waste (paper pulp, animal waste) as fuel
- Low capital costs for co-firing methods (not considered a renewable method)

Disadvantages:

- Fuel transport costs
- Fuel handling
- Competition with agriculture projects
- Boiler contamination

A conventional steam boiler plant burning solid biomass fuel has an average capital investment cost of $2,000 - $2,500 per kW of installed capacity. Average overall costs are approximately 6.4 - 11.3 cents per kWh. Refer to Tables 5-1 and 5-2 for cost comparisons to other renewable technologies.

A well-organized biomass operation needs approximately 10,000 dry tons of fuel per year to supply a capacity of 1 MW.

Geothermal

Geothermal power is produced by drilling wells deep into the earth's crust to obtain heat energy from geothermal reservoirs. Production methods include dry steam, hot water reservoir, and binary systems. Electricity can be produced by steam turbine directly using the geothermal resource or by using the resource to heat a secondary fluid. Geothermal activity in the U.S. lies along the San Andreas Fault, giving western areas the greatest potential.

Advantages:

- Small amounts of emissions for open-loop, zero emissions for closed-loop
- High capacity factor

Disadvantages:

- Depletion of wells if the wells are not regulated
- Site specificity
- Hydrogen sulfide emissions
- Closed-loop causes reservoir damage

Capital costs for geothermal power plants average $1,600 - $2,200 per kW. Factors of installment costs include well depth, well productivity, temperature of the resource, and technology. In addition, royalties must be paid to the geothermal resource owners based on monthly usage. Average overall costs are in the range of 3 to 8 cents per kWh. Refer to Tables 5-1 and 5-2 for cost comparisons to other technologies.

According to the Geothermal Education Office, the top states with geothermal potential are Nevada, California, Oregon, New Mexico, Washington, and Utah.

Wind

Wind power is obtained by using turbines to capture the kinetic energy of the wind. Current turbines are typically 200 feet tall with a 74 foot blade radius and need at least 13 - 15 mph of wind speed to produce cost effective energy. Typically, wind power plants need approximately 100 acres of land per turbine to prevent flow interference.

Advantages:

- Zero emissions
- Zero fuel cost
- Remote area access

Disadvantages:

- Visible
- Environmental hazard (birds flying into the turbine blades)
- Lack of dispatchability
- Large land requirements

The current generation of wind turbines average 1.5 MW each and generally cost $1,000 per kW of installed capacity. Land payments must also be made if towers are sited on private property. Average overall costs range from 4 - 6 cents per kWh.

The Department of Energy (DOE) introduced a scale for measuring wind classes for energy production. On a scale from Class 1 to 7, with Class 7 exhibiting the greatest wind potential, areas of Class 3 or higher wind resource can be found throughout the Southern Rocky Mountain region. Colorado has wind resources consistent with utility-scale production. Significant contiguous areas of good resource with embedded regions of excellent resource are found in the eastern quarter of the state. The excellent resource areas within the eastern quarter of Colorado are concentrated near the New Mexico and Nebraska borders. An area of excellent-to-outstanding resource is located along the Wyoming border north of Fort Collins. The exposed ridge crests of the Front Range, the Continental Divide, and in western Colorado also have good to outstanding wind resource.

Solar

Solar energy production uses two different methods; photovoltaic and solar thermal. Photovoltaic systems use radiation to knock electrons free of flat-plate semiconductor material, while solar thermal systems concentrate solar energy to heat fluid which is exchanged to steam and then powers a steam turbine generator. Solar thermal power concentrates heat by trough, power tower, or dish systems. Both solar thermal and photovoltaic methods require approximately 10 acres per MW.

Advantages:

- Zero emissions
- Zero fuel costs, unless hybrid
- Highest production in summertime
- Photovoltaic systems have no moving parts
    - Silent operation
    - Minimal maintenance

Disadvantages:

- Lack of dispatchability
- Site specificity
- Large amount of land per kW
- High capital investment

Solar thermal power plants cost $5,000 per kW of installed capacity when last built in 1990. Photovoltaic systems are slightly higher, averaging $6,000 per kW. Solar thermal technologies have average overall costs of 9 - 12 cents per kWh and photovoltaic systems range from 21 – 35 cents per kWh.

Fuel Cell

A fuel cell produces electricity through a chemical reaction between hydrogen and oxygen. Hydrogen is fed into one side of the cell while oxygen is supplied into the other. Electrons and protons from the hydrogen follow separate paths and combine with the oxygen to form water. As long as fuel is provided, this chemical process will produce electricity.

Advantages:

- Zero emissions
- High capacity factor
- Silent operation
- Storable, non-toxic fuel

Disadvantages:

- High capital cost (compared to other renewable resources)
- Complex renewable systems for hydrogen supply
- Safety issues

Natural gas fuel cells average costs are $4,700 per kW of installed capacity. This value may increase significantly with other renewable energy installation providing the hydrogen supply. Average overall costs range from 18 – 25 cents per kWh.

Fuel cell technology is not location specific, giving Colorado as much potential as other sites in the U.S. However, to be considered a complete renewable system, other renewable technologies must be used to produce the hydrogen fuel used to power the fuel cell. Available renewable technologies have been presented in the previous sections.

Cost Overview

The following Table 5-1 displays current cost comparisons for the renewable technologies reviewed.

Table 5-1
Technology Comparison for Year 2004

	Overall Cost per kWh	Capital Cost per kW	Capacity Factor
Biomass[(1)]	6¢–11¢	$2,000–$2,500	85%
Geothermal	3¢–8¢	$1,400–$2,400	87%
Wind	4¢–6¢	$900–$1,100	30%
Solar (Th)	9¢–13¢	$5,000	30%
Solar (PV)	21¢–35¢	$6,000	25%
Fuel Cell[(2)]	18¢–25¢	$4,500–$30,000	95%
New coal plant	3¢– 4¢	$1,200 - $1,600	95%

(1) Assumes conventional combustion
(2) Assumes constant supply of natural gas as feedstock
Sources: National Renewable Energy Laboratory ("NREL"), Navigant Consulting, ICF Consulting

Cost trends for renewable technologies have been decreasing as technologies and efficiencies improve and installed capacity increases. While it is impossible to predict how cost will change in the future, it is expected that costs will continue to improve. Table 5-2 identifies potential technology costs in year 2020.

Table 5-2
Renewable Technology Comparison for Year 2020
(in 2005 dollars)

	Overall Cost per kWh	Capital Cost per kW	Capacity Factor
Biomass[(1)]	5¢–6¢	$1,200	90%
Geothermal	2¢–4¢	$1,400	90%
Wind	< 4¢	< $ 800	35%
Solar (Th)	< 5¢	$2,200	30%
Solar (PV)	7¢–10¢	$3,700	30%
Fuel Cell[(2)]	N/A	N/A	95%

(1) Assumes conventional combustion
(2) Assumes constant supply of natural gas as feedstock
Sources: NREL, Navigant Consulting, ICF Consulting

Renewable Technology Incentives

The Energy Policy Act of 2005 (the "Act") was signed into law on August 8, 2005. It provides several renewable energy incentives. The Act provides for both a production tax credit for selected renewable technologies and for tax-credit bonds for renewable energy projects.

The Act extends the Production Tax Credit ("PTC") for wind, biomass, geothermal, trash combustion, landfill gas and small irrigation hydro facilities through December 31, 2007. The PTC offers a tax credit of up to 1.9 cents per kilowatt-hour generated to be applied against federal income tax liability. Since renewable energy is typically not yet cost competitive with other forms of generation, the PTC has been an important incentive in promoting wind energy development over the past decade. More recently, with the expansion in technologies covered by the PTC, additional types of renewable options have benefited as well. As investor-owned utilities and developers customarily have federal income tax liabilities, this program has been structured to be attractive to them. As a result, most of the wind generation installed in the U.S. has been built by for-profit companies. However, the PTC does offer benefits to municipal utilities in that it lowers the price the utility must pay under a wind power purchase agreement.

Municipal utilities generally do not have federal income tax liabilities, so the PTC does not provide a monetary incentive for them to build renewable energy. To provide that incentive for the non-profit utility sector, the Act includes a provision for issuing up to $800 million in tax-credit bonds to finance the cost of renewable energy projects.

The Clean Renewable Energy Bonds ("CREBs") are tax-credit bonds that provide the bondholder with an income tax credit in lieu of cash interest payments. With a conventional bond, the issuer pays interest to the bond holder. But with a tax credit bond, the federal government pays a tax credit to the bondholder instead of the issuer paying interest. The net effect of the CREBs is to provide municipal utilities with the opportunity to build renewable energy generation with zero-percent financing.

CREBs are available for issuance beginning January 1, 2006 with the authority to issue them currently set to expire December 31, 2007. According to the Act, CREBs may be issued by any governmental body, defined as any State, territory, possession of the United States, the District of Columbia, Indian tribal government, and any political subdivision thereof.

City of Boulder
City Manager's Office
PO Box 791
Boulder, CO 80306
Phone: 303-441-3090
FAX: 303-441-4478

To: Todd Anderson
Community Service Manager
Xcel Energy
2655 N. 63rd St
Boulder, CO 80301-2934

From: Frank Bruno, City Manager

Re: Information request

As you may be aware, the Boulder City Council has directed staff to begin to investigate the logistics and the costs and benefits of municipal control of the electric utility. In accordance with Article 6, Reports to the City, Article 14, of the Franchise Agreement between the City and Xcel (approved through the November 2, 1993 municipal election) regarding the city's right to purchase or condemn the system, and specifically, Section 14.2, Continued Cooperation by Company, the city requests the following information be provided:

1. A list of all real property and leasehold interests owned by the Company within the city, as well as within the Boulder Valley Comprehensive Plan area. The City requests that this information be provided in a readily accessible electronic format as well as be accompanied by a map (or maps) which show(s) the location of each listed property.

This request is made in accordance with Article 6, Section 6.1 (1) - Reports on Company Operations.

2. An estimate the Company's FERC defined "stranded costs," if any, which may or may not exist and be applicable to the City in the event the City pursues its rights under Article 14 of the above-referenced Franchise Agreement.

The City requests that Xcel provide this information in a readily accessible electronic format and that it be consistent with FERC's Order No. 888. With respect to this request, Xcel should assume that the City would become a wholesale customer on August 3, 2010, and assume that the entire load in the City currently served by Xcel would be served by a city municipal system using Xcel's transmission service. This request does not imply the existence of stranded cost, nor does it in any way suggest that the City, at some point in the future, may choose to deny the existence of such costs before the appropriate jurisdictional authority.

3. 2004 FERC Form Annual Report and comparable annual report data filed by Xcel Energy (Xcel) to the Colorado Public Utility Commission (CPUC).

4. Copy of Xcel's most recent retail cost of service study approved by the CPUC. If Xcel has filed for new retail rates since the last study was adopted, then we request a copy of the proposed rate filing.

5. Schedule of Xcel's current approved depreciation rates and factors (average service lives, survivor curves, remaining service lives, and net salvage ratios). Copy of Xcel's most recent depreciation study filed with the CPUC.

6. Detailed billing data (inventory) and maps for the streetlights in the City.

7. Copies of electric bills for the city of Boulder, large industrial/commercial customers, schools and educational institutions, hospitals, etc.

8. Load forecast for the city of Boulder, monthly energy and peaks 2005 through 2024, including documentation on assumptions (specifically regarding the 29th Street mall).

9. A brief description of the 'City of Boulder' versus 'Boulder Division' (as referenced in Annual Report to the City).

If you have any questions or need more information about these requests please contact Kara Mertz at 303-441-3004. Thank you in advance for your cooperation.

Sincerely,

Frank W. Bruno
City Manager

Year		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Item											
Xcel Average Retail Rate Summary ($/MWh)											
Average Xcel System Rate ($/MWh)		$77.79	$75.80	$76.59	$77.02	$74.35	$77.06	$78.48	$79.76	$82.02	$81.46
Boulder Retail Mix Adjustment		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Adjusted Xcel Boulder Equivalent Rate ($/MWH)		$77.79	$75.80	$76.59	$77.02	$74.35	$77.06	$78.48	$79.76	$82.02	$81.46
Rate Reduction	0%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Average Boulder Retail Rate ($/MWh)		$77.79	$75.80	$76.59	$77.02	$74.35	$77.06	$78.48	$79.76	$82.02	$81.46
Boulder Municipal System - Cost Drivers											
Retail Sales (MWH)		1,176,152	1,177,587	1,179,022	1,180,460	1,181,899	1,183,340	1,184,783	1,186,227	1,187,674	1,189,122
No. of Customers		43,555	43,608	43,661	43,715	43,768	43,821	43,875	43,928	43,982	44,035
Xcel Price of Purchased Power ($/MWh)		$48.96	$49.53	$48.47	$47.46	$46.29	$45.03	$46.21	$46.85	$47.49	$48.86
Market Adjustment ($/MWh)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Renewable Adjustment ($/MWh)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Purchased Power ($/MWh)		$48.96	$49.53	$48.47	$47.46	$46.29	$45.03	$46.21	$46.85	$47.49	$48.86
Xcel Transmission Tariff ($/MWh)		$4.70	$4.70	$4.70	$4.70	$4.82	$4.94	$4.94	$4.94	$4.94	$4.94
Distribution Cost ($/Customer)		$141.00	$144.53	$148.14	$151.84	$155.64	$159.53	$163.52	$167.60	$171.79	$176.09
Customer Service Cost ($/Customer)		$86.00	$88.15	$90.35	$92.61	$94.93	$97.30	$99.73	$102.23	$104.78	$107.40
Administration & General Cost ($/Customer)		$117.00	$119.93	$122.92	$126.00	$129.15	$132.37	$135.68	$139.08	$142.55	$146.12
Other Income (Connection Fees, Service Charges, etc) ($/Customer)		$5.79	$5.93	$6.08	$6.23	$6.39	$6.55	$6.71	$6.88	$7.05	$7.23
Boulder Municipal System - Cash Flow											
Revenue											
Retail Rate Revenue		$91,493,044	$89,258,077	$90,304,921	$90,916,033	$87,873,237	$91,187,597	$92,978,419	$94,611,326	$97,411,546	$96,866,163
Other Income (Connection Fees, Service Charges, etc)		$252,137	$258,755	$265,548	$272,518	$279,672	$287,013	$294,547	$302,279	$310,214	$318,357
Interest Income	$0	$708,289	$714,002	$710,174	$706,652	$702,952	$698,712	$708,306	$714,808	$721,349	$732,289
Total Revenue		$92,453,470	$90,230,835	$91,280,643	$91,895,204	$88,855,861	$92,173,322	$93,981,272	$95,628,412	$98,443,109	$97,916,809
Operation and Maintenance Expense											
Purchased Power Cost		$57,583,750	$58,326,274	$57,150,219	$56,024,893	$54,714,189	$53,280,467	$54,744,322	$55,578,199	$56,407,769	$58,104,791
Wheeling Cost		$5,527,917	$5,534,657	$5,541,405	$5,548,161	$5,693,799	$5,843,259	$5,850,384	$5,857,517	$5,864,659	$5,871,809
Total Purchased Power and Wheeling (Non-O&M)		$63,111,667	$63,860,931	$62,691,623	$61,573,054	$60,407,987	$59,123,726	$60,594,705	$61,435,716	$62,272,428	$63,976,600
Distribution Cost		$6,141,255	$6,302,461	$6,467,899	$6,637,680	$6,811,917	$6,990,728	$7,174,233	$7,362,554	$7,555,819	$7,754,157
Customer Service Cost		$3,745,730	$3,844,054	$3,944,960	$4,048,514	$4,154,786	$4,263,848	$4,375,773	$4,490,636	$4,608,514	$4,729,486
Adminstrative & General Cost		$5,095,935	$5,229,702	$5,366,980	$5,507,862	$5,652,442	$5,800,817	$5,953,087	$6,109,354	$6,269,722	$6,434,301
Total Operation and Maintenance Expense		$78,094,587	$79,237,148	$78,471,462	$77,767,109	$77,027,132	$76,179,119	$78,097,798	$79,398,260	$80,706,483	$82,894,545
Margin Available for Debt Service		$14,358,883	$10,993,687	$12,809,181	$14,128,094	$11,828,729	$15,994,204	$15,883,474	$16,230,153	$17,736,626	$15,022,264
Debt Service											
Interest Expense	6%	$7,684,881	$7,572,070	$7,658,971	$7,629,735	$7,521,175	$7,538,326	$7,311,739	$7,102,205	$6,857,626	$6,513,108
Principal Paid		$1,880,175	-$1,448,352	$487,277	$1,809,324	-$285,849	$3,776,456	$3,492,239	$4,076,315	$5,741,956	$3,277,921
Principal Coverage Adjustment		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Debt Service		$9,565,056	$6,123,718	$8,146,249	$9,439,059	$7,235,327	$11,314,782	$10,803,978	$11,178,519	$12,599,581	$9,791,029
Debt Service Coverage		**1.50**	**1.80**	**1.57**	**1.50**	**1.63**	**1.41**	**1.47**	**1.45**	**1.41**	**1.53**
Depreciation Expense (Renewals / Replacement Proxy)		$2,020,223	$2,020,223	$2,020,223	$2,020,223	$2,020,223	$2,020,223	$2,020,223	$2,020,223	$2,020,223	$2,020,223
Cash to Working Capital Reserve		$0	$142,820	-$95,711	-$88,044	-$92,497	-$106,002	$239,835	$162,558	$163,528	$273,508
Payment in Lieu of Taxes	3.0%	$2,773,604	$2,706,925	$2,738,419	$2,756,856	$2,665,676	$2,765,200	$2,819,438	$2,868,852	$2,953,293	$2,937,504

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Xcel Average Retail Rate Summary ($/MWh)												
Average Xcel System Rate ($/MWh)		$83.96	$86.72	$88.83	$90.51	$94.27	$92.89	$95.37	$98.05	$100.79	$103.04	$102.31
Boulder Retail Mix Adjustment		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Adjusted Xcel Boulder Equivalent Rate ($/MWH)		$83.96	$86.72	$88.83	$90.51	$94.27	$92.89	$95.37	$98.05	$100.79	$103.04	$102.31
Rate Reduction	0%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Average Boulder Retail Rate ($/MWh)		$83.96	$86.72	$88.83	$90.51	$94.27	$92.89	$95.37	$98.05	$100.79	$103.04	$102.31
Boulder Municipal System - Cost Drivers												
Retail Sales (MWH)		1,190,572	1,192,023	1,193,477	1,194,932	1,196,389	1,197,847	1,199,308	1,200,770	1,202,234	1,203,700	1,205,167
No. of Customers		44,089	44,143	44,197	44,250	44,304	44,358	44,412	44,467	44,521	44,575	44,629
Xcel Price of Purchased Power ($/MWh)		$49.98	$52.10	$53.89	$55.38	$56.58	$58.92	$59.55	$61.17	$63.08	$64.90	$66.47
Market Adjustment ($/MWh)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Renewable Adjustment ($/MWh)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Purchased Power ($/MWh)		$49.98	$52.10	$53.89	$55.38	$56.58	$58.92	$59.55	$61.17	$63.08	$64.90	$66.47
Xcel Transmission Tariff ($/MWh)		$5.06	$5.06	$5.06	$5.06	$5.06	$5.06	$5.19	$5.19	$5.19	$5.19	$5.19
Distribution Cost ($/Customer)		$180.49	$185.00	$189.63	$194.37	$199.23	$204.21	$209.32	$214.55	$219.91	$225.41	$231.04
Customer Service Cost ($/Customer)		$110.09	$112.84	$115.66	$118.55	$121.52	$124.55	$127.67	$130.86	$134.13	$137.48	$140.92
Administration & General Cost ($/Customer)		$149.77	$153.51	$157.35	$161.29	$165.32	$169.45	$173.69	$178.03	$182.48	$187.04	$191.72
Other Income (Connection Fees, Service Charges, etc) ($/Customer)		$7.41	$7.60	$7.79	$7.98	$8.18	$8.38	$8.59	$8.81	$9.03	$9.25	$9.49
Boulder Municipal System - Cash Flow												
Revenue												
Retail Rate Revenue		$99,956,213	$103,371,283	$106,013,335	$108,151,252	$112,786,141	$111,269,450	$114,379,828	$117,731,614	$121,178,709	$124,025,422	$123,294,860
Other Income (Connection Fees, Service Charges, etc)		$326,713	$335,290	$344,091	$353,123	$362,392	$371,905	$381,668	$391,686	$401,968	$412,519	$423,348
Interest Income	$0	$742,526	$758,122	$771,817	$783,840	$794,201	$811,492	$819,405	$832,605	$847,591	$862,229	$875,412
Total Revenue		$101,025,452	$104,464,694	$107,129,243	$109,288,215	$113,942,734	$112,452,847	$115,580,900	$118,955,906	$122,428,268	$125,300,170	$124,593,620
Operation and Maintenance Expense												
Purchased Power Cost		$59,501,431	$62,103,556	$64,312,266	$66,172,764	$67,686,716	$70,572,356	$71,415,597	$73,452,785	$75,831,307	$78,124,332	$80,109,855
Wheeling Cost		$6,025,942	$6,033,289	$6,040,646	$6,048,011	$6,055,385	$6,062,768	$6,221,914	$6,229,500	$6,237,095	$6,244,699	$6,252,313
Total Purchased Power and Wheeling (Non-O&M)		$65,527,373	$68,136,845	$70,352,911	$72,220,775	$73,742,101	$76,635,123	$77,637,511	$79,682,284	$82,068,402	$84,369,031	$86,362,169
Distribution Cost		$7,957,702	$8,166,589	$8,380,960	$8,600,958	$8,826,731	$9,058,430	$9,296,211	$9,540,234	$9,790,663	$10,047,665	$10,311,414
Customer Service Cost		$4,853,634	$4,981,040	$5,111,791	$5,245,974	$5,383,680	$5,525,000	$5,670,030	$5,818,866	$5,971,610	$6,128,363	$6,289,231
Adminstrative & General Cost		$6,603,199	$6,776,532	$6,954,414	$7,136,965	$7,324,309	$7,516,570	$7,713,878	$7,916,365	$8,124,167	$8,337,424	$8,556,279
Total Operation and Maintenance Expense		$84,941,908	$88,061,007	$90,800,076	$93,204,672	$95,276,820	$98,735,123	$100,317,629	$102,957,750	$105,954,842	$108,882,484	$111,519,093
Margin Available for Debt Service		$16,083,544	$16,403,687	$16,329,166	$16,083,543	$18,665,914	$13,717,724	$15,263,271	$15,998,156	$16,473,426	$16,417,687	$13,074,527
Debt Service												
Interest Expense	6%	$6,316,433	$6,048,821	$5,760,172	$5,460,621	$5,159,213	$4,690,662	$4,498,604	$4,193,852	$3,840,729	$3,446,829	$3,037,289
Principal Paid		$4,460,204	$4,810,815	$4,992,510	$5,023,477	$7,809,178	$3,200,965	$5,079,203	$5,885,388	$6,564,989	$6,825,674	$3,949,630
Principal Coverage Adjustment		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Debt Service		$10,776,637	$10,859,636	$10,752,682	$10,484,098	$12,968,390	$7,891,628	$9,577,807	$10,079,241	$10,405,718	$10,272,503	$6,986,919
Debt Service Coverage		**1.49**	**1.51**	**1.52**	**1.53**	**1.44**	**1.74**	**1.59**	**1.59**	**1.58**	**1.60**	**1.87**
Depreciation Expense (Renewals / Replacement Proxy)		$2,020,223	$2,020,223	$2,020,223	$2,020,223	$2,020,223	$2,020,223	$2,020,223	$2,020,223	$2,020,223	$2,020,223	$2,020,223
Cash to Working Capital Reserve		$255,920	$389,887	$342,384	$300,574	$259,018	$432,288	$197,813	$330,015	$374,637	$365,955	$329,576
Payment in Lieu of Taxes	3.0%	$3,030,764	$3,133,941	$3,213,877	$3,278,646	$3,418,282	$3,373,585	$3,467,427	$3,568,677	$3,672,848	$3,759,005	$3,737,809

		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Xcel Average Retail Rate Summary ($/MWh)											
Average Xcel System Rate ($/MWh)		$106.13	$108.93	$111.87	$110.46	$113.54	$116.44	$119.54	$117.76	$121.06	$124.23
Boulder Retail Mix Adjustment		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Adjusted Xcel Boulder Equivalent Rate ($/MWH)		$106.13	$108.93	$111.87	$110.46	$113.54	$116.44	$119.54	$117.76	$121.06	$124.23
Rate Reduction	0%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Average Boulder Retail Rate ($/MWh)		$106.13	$108.93	$111.87	$110.46	$113.54	$116.44	$119.54	$117.76	$121.06	$124.23
Boulder Municipal System - Cost Drivers											
Retail Sales (MWH)		1,206,637	1,208,108	1,209,581	1,211,056	1,212,532	1,214,011	1,215,491	1,216,973	1,218,457	1,219,942
No. of Customers		44,684	44,738	44,793	44,848	44,902	44,957	45,012	45,067	45,122	45,177
Xcel Price of Purchased Power ($/MWh)		$67.47	$70.38	$72.43	$74.63	$75.25	$77.36	$79.55	$81.90	$82.46	$84.76
Market Adjustment ($/MWh)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Renewable Adjustment ($/MWh)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Purchased Power ($/MWh)		$67.47	$70.38	$72.43	$74.63	$75.25	$77.36	$79.55	$81.90	$82.46	$84.76
Xcel Transmission Tariff ($/MWh)		$5.19	$5.19	$5.19	$5.19	$5.19	$5.19	$5.19	$5.19	$5.19	$5.19
Distribution Cost ($/Customer)		$236.82	$242.74	$248.81	$255.03	$261.41	$267.94	$274.64	$281.51	$288.54	$295.76
Customer Service Cost ($/Customer)		$144.44	$148.06	$151.76	$155.55	$159.44	$163.43	$167.51	$171.70	$175.99	$180.39
Administration & General Cost ($/Customer)		$196.51	$201.42	$206.46	$211.62	$216.91	$222.33	$227.89	$233.59	$239.43	$245.42
Other Income (Connection Fees, Service Charges, etc) ($/Customer)		$9.72	$9.97	$10.22	$10.47	$10.73	$11.00	$11.28	$11.56	$11.85	$12.14
Boulder Municipal System - Cash Flow											
Revenue											
Retail Rate Revenue		$128,059,252	$131,601,685	$135,312,924	$133,774,076	$137,670,648	$141,364,758	$145,296,198	$143,314,076	$147,502,401	$151,556,492
Other Income (Connection Fees, Service Charges, etc)		$434,461	$445,865	$457,569	$469,580	$481,906	$494,556	$507,538	$520,861	$534,534	$548,565
Interest Income	$0	$885,279	$906,752	$923,213	$940,644	$948,698	$965,851	$983,602	$1,002,500	$1,010,631	$1,029,487
Total Revenue		$129,378,991	$132,954,303	$136,693,706	$135,184,300	$139,101,252	$142,825,165	$146,787,338	$144,837,438	$149,047,566	$153,134,544
Operation and Maintenance Expense											
Purchased Power Cost		$81,415,222	$85,024,617	$87,613,573	$90,378,481	$91,249,015	$93,920,335	$96,691,396	$99,671,606	$100,477,642	$103,407,340
Wheeling Cost		$6,259,936	$6,267,569	$6,275,210	$6,282,861	$6,290,522	$6,298,191	$6,305,870	$6,313,559	$6,321,257	$6,328,964
Total Purchased Power and Wheeling (Non-O&M)		$87,675,158	$91,292,186	$93,888,784	$96,661,342	$97,539,537	$100,218,526	$102,997,266	$105,985,164	$106,798,899	$109,736,303
Distribution Cost		$10,582,085	$10,859,862	$11,144,931	$11,437,482	$11,737,713	$12,045,824	$12,362,024	$12,686,524	$13,019,542	$13,361,301
Customer Service Cost		$6,454,322	$6,623,746	$6,797,617	$6,976,053	$7,159,172	$7,347,099	$7,539,958	$7,737,880	$7,940,997	$8,149,446
Adminstrative & General Cost		$8,780,879	$9,011,375	$9,247,921	$9,490,677	$9,739,804	$9,995,471	$10,257,850	$10,527,115	$10,803,449	$11,087,037
Total Operation and Maintenance Expense		$113,492,444	$117,787,169	$121,079,253	$124,565,553	$126,176,226	$129,606,921	$133,157,098	$136,936,683	$138,562,886	$142,334,087
Margin Available for Debt Service		$15,886,547	$15,167,134	$15,614,453	$10,618,747	$12,925,026	$13,218,245	$13,630,240	$7,900,754	$10,484,679	$10,800,457
Debt Service											
Interest Expense	6%	$2,800,311	$2,384,033	$2,009,788	$1,585,461	$1,434,156	$1,128,380	$807,017	$449,680	$412,884	$210,272
Principal Paid		$6,937,974	$6,237,408	$7,072,120	$2,521,746	$5,096,275	$5,356,050	$5,955,608	$613,279	$3,376,870	$3,504,525
Principal Coverage Adjustment		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Debt Service		$9,738,285	$8,621,441	$9,081,908	$4,107,207	$6,530,431	$6,484,429	$6,762,625	$1,062,960	$3,789,754	$3,714,797
Debt Service Coverage		**1.63**	**1.76**	**1.72**	**2.59**	**1.98**	**2.04**	**2.02**	**7.43**	**2.77**	**2.91**
Depreciation Expense (Renewals / Replacement Proxy)		$2,020,223	$2,020,223	$2,020,223	$2,020,223	$2,020,223	$2,020,223	$2,020,223	$2,020,223	$2,020,223	$2,020,223
Cash to Working Capital Reserve		$246,669	$536,841	$411,510	$435,788	$201,334	$428,837	$443,772	$472,448	$203,275	$471,400
Payment in Lieu of Taxes	3.0%	$3,881,370	$3,988,629	$4,100,811	$4,055,529	$4,173,038	$4,284,755	$4,403,620	$4,345,123	$4,471,427	$4,594,036

Year		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Net Margin		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Free Cash Flow for Debt Service		$9,565,056	$6,123,718	$8,146,249	$9,439,059	$7,235,327	$11,314,782	$10,803,978	$11,178,519	$12,599,581	$9,791,029
Boulder Municipal System - Cost of Service											
Total Revenue Requirement - Retail Rates		$91,493,044	$89,258,077	$90,304,921	$90,916,033	$87,873,237	$91,187,597	$92,978,419	$94,611,326	$97,411,546	$96,866,163
Total Revenue Requirement - Retail Rates ($/MWh)		$77.79	$75.80	$76.59	$77.02	$74.35	$77.06	$78.48	$79.76	$82.02	$81.46
Outstanding Principal Balance	**$128,081,347**	$126,201,171	$127,649,524	$127,162,246	$125,352,922	$125,638,771	$121,862,315	$118,370,076	$114,293,762	$108,551,806	$105,273,886
System Reserves											
Beginning Balance		0	$17,707,236	$17,850,056	$17,754,346	$17,666,302	$17,573,804	$17,467,803	$17,707,638	$17,870,195	$18,033,723
Deposits											
Working Capital		$10,014,351	$142,820	-$95,711	-$88,044	-$92,497	-$106,002	$239,835	$162,558	$163,528	$273,508
Net Margin		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Debt Service Reserve		$7,692,885	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal Deposits		$17,707,236	$142,820	-$95,711	-$88,044	-$92,497	-$106,002	$239,835	$162,558	$163,528	$273,508
Ending Balance		$17,707,236	$17,850,056	$17,754,346	$17,666,302	$17,573,804	$17,467,803	$17,707,638	$17,870,195	$18,033,723	$18,307,231
Working Capital Cash Balance		$10,014,351	$10,157,171	$10,061,461	$9,973,417	$9,880,919	$9,774,918	$10,014,753	$10,177,310	$10,340,838	$10,614,346
Debt Service Reserve		$7,692,885	$7,692,885	$7,692,885	$7,692,885	$7,692,885	$7,692,885	$7,692,885	$7,692,885	$7,692,885	$7,692,885
Other Reserves		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

r		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Net Margin		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Free Cash Flow for Debt Service		$10,776,637	$10,859,636	$10,752,682	$10,484,098	$12,968,390	$7,891,628	$9,577,807	$10,079,241	$10,405,718	$10,272,503	$6,986,919
Boulder Municipal System - Cost of Service												
Total Revenue Requirement - Retail Rates		$99,956,213	$103,371,283	$106,013,335	$108,151,252	$112,786,141	$111,269,450	$114,379,828	$117,731,614	$121,178,709	$124,025,422	$123,294,860
Total Revenue Requirement - Retail Rates ($/MWh)		$83.96	$86.72	$88.83	$90.51	$94.27	$92.89	$95.37	$98.05	$100.79	$103.04	$102.31
Outstanding Principal Balance	**$128,081,347**	$100,813,682	$96,002,868	$91,010,358	$85,986,881	$78,177,704	$74,976,738	$69,897,535	$64,012,147	$57,447,158	$50,621,484	$46,671,854
System Reserves												
Beginning Balance		$18,307,231	$18,563,151	$18,953,039	$19,295,422	$19,595,997	$19,855,015	$20,287,303	$20,485,117	$20,815,132	$21,189,768	$21,555,723
Deposits												
Working Capital		$255,920	$389,887	$342,384	$300,574	$259,018	$432,288	$197,813	$330,015	$374,637	$365,955	$329,576
Net Margin		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Debt Service Reserve		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal Deposits		$255,920	$389,887	$342,384	$300,574	$259,018	$432,288	$197,813	$330,015	$374,637	$365,955	$329,576
Ending Balance		$18,563,151	$18,953,039	$19,295,422	$19,595,997	$19,855,015	$20,287,303	$20,485,117	$20,815,132	$21,189,768	$21,555,723	$21,885,299
Working Capital Cash Balance		$10,870,266	$11,260,154	$11,602,537	$11,903,112	$12,162,130	$12,594,418	$12,792,232	$13,122,247	$13,496,883	$13,862,838	$14,192,414
Debt Service Reserve		$7,692,885	$7,692,885	$7,692,885	$7,692,885	$7,692,885	$7,692,885	$7,692,885	$7,692,885	$7,692,885	$7,692,885	$7,692,885
Other Reserves		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

r		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Net Margin		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Free Cash Flow for Debt Service		$9,738,285	$8,621,441	$9,081,908	$4,107,207	$6,530,431	$6,484,429	$6,762,625	$1,062,960	$3,789,754	$3,714,797
Boulder Municipal System - Cost of Service											
Total Revenue Requirement - Retail Rates		$128,059,252	$131,601,685	$135,312,924	$133,774,076	$137,670,648	$141,364,758	$145,296,198	$143,314,076	$147,502,401	$151,556,492
Total Revenue Requirement - Retail Rates ($/MWh)		$106.13	$108.93	$111.87	$110.46	$113.54	$116.44	$119.54	$117.76	$121.06	$124.23
Outstanding Principal Balance	**$128,081,347**	$39,733,880	$33,496,472	$26,424,352	$23,902,606	$18,806,331	$13,450,282	$7,494,674	$6,881,395	$3,504,525	$0
System Reserves											
Beginning Balance		$21,885,299	$22,131,968	$22,668,809	$23,080,320	$23,516,107	$23,717,441	$24,146,278	$24,590,050	$25,062,498	$25,265,774
Deposits											
Working Capital		$246,669	$536,841	$411,510	$435,788	$201,334	$428,837	$443,772	$472,448	$203,275	$471,400
Net Margin		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Debt Service Reserve		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal Deposits		$246,669	$536,841	$411,510	$435,788	$201,334	$428,837	$443,772	$472,448	$203,275	$471,400
Ending Balance		$22,131,968	$22,668,809	$23,080,320	$23,516,107	$23,717,441	$24,146,278	$24,590,050	$25,062,498	$25,265,774	$25,737,174
Working Capital Cash Balance		$14,439,083	$14,975,924	$15,387,435	$15,823,222	$16,024,556	$16,453,393	$16,897,165	$17,369,613	$17,572,889	$18,044,289
Debt Service Reserve		$7,692,885	$7,692,885	$7,692,885	$7,692,885	$7,692,885	$7,692,885	$7,692,885	$7,692,885	$7,692,885	$7,692,885
Other Reserves		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013
Net Cash Available for Purchase									
Gross Price		$128,081,347							
Bond Issuance Expenses		$4,482,847							
Debt Service Reserve Fund	$0	$7,692,885							
Working Capital		$10,014,351							
Purchase Price w/o Severance & Stranded Investment		**$105,891,263**							
Less Severance		$4,928,250							
Less Stranded Investment		$20,443,685							
Purchase Price		**$80,519,328**							

Annual Levelized Debt Service Payment (30 Years)		100%
Term	30	$7,692,885
Working Capital Balance		

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
	Historical	Historical	Historical	Historical	Historical	Projected	Projected	Projected	Projected	Projected	Projected	Projected
Revenue Requirement												
Operation and Maintenance Expense												
Production Cost												
Fixed -Non Fuel	$1,659,132,470	$2,247,446,717	$2,138,952,599	$1,128,212,839	$1,470,771,929	$96,380,192	$99,472,772	$101,893,658	$104,256,616	$126,161,774	$127,888,168	$131,636,128
Variable (Fuel)	$299,025,157	$375,732,579	$315,527,808	$342,948,664	$351,036,896	$351,140,723	$369,476,900	$371,322,626	$361,582,418	$405,470,778	$379,436,190	$399,357,059
Purchased Power (Split Out)						$1,326,552,479	$1,300,691,969	$1,261,297,799	$1,192,627,526	$1,146,208,359	$1,151,468,999	$1,169,869,274
New Resource Capital												
Total Production Cost	$1,958,157,627	$2,623,179,296	$2,454,480,407	$1,471,161,503	$1,821,808,825	$1,774,073,394	$1,769,641,641	$1,734,514,083	$1,658,466,560	$1,677,840,911	$1,658,793,357	$1,700,862,461
Transmission Cost	$50,863,014	$86,831,239	$47,135,738	$41,645,026	$30,562,856	$32,760,619	$34,403,632	$36,114,041	$37,873,926	$39,735,319	$41,725,799	$43,841,087
Distribution Cost	$47,909,475	$46,262,925	$48,441,528	$58,773,514	$66,007,080	$70,753,623	$74,302,065	$77,996,062	$81,796,913	$85,816,993	$90,115,864	$94,684,283
Customer Service	$47,401,377	$48,708,361	$39,720,897	$42,253,649	$46,898,479	$50,270,930	$52,792,122	$55,416,732	$58,117,263	$60,973,557	$64,027,934	$67,273,827
A&G	$95,269,694	$141,539,236	$132,351,050	$151,977,355	$137,736,392	$147,640,960	$155,045,465	$162,753,694	$170,684,898	$179,073,564	$188,043,980	$197,576,859
Total Operation and Maintenance Expense	$2,199,601,187	$2,946,521,057	$2,722,129,620	$1,765,811,047	$2,103,013,632	$2,075,499,525	$2,086,184,926	$2,066,794,612	$2,006,939,560	$2,043,440,345	$2,042,706,934	$2,104,238,517
Total O&M Form 1	$2,199,601,187	$2,946,521,057	$2,722,129,620	$1,765,811,047	$2,103,013,632							
Check												
Depreciation Expense	$119,154,804	$124,188,571	$122,592,178	$118,619,097	$117,271,004	$171,360,255	$128,453,940	$132,246,086	$134,522,372	$145,136,871	$160,685,719	$168,194,969
Amortization Expense	$11,114,881	$18,982,570	$26,294,757	$19,650,879	$13,966,112	$25,628,684	$19,211,604	$19,778,759	$20,119,200	$21,706,708	$24,032,197	$25,155,283
Total	$130,269,685	$143,171,141	$148,886,935	$138,269,976	$131,237,116	$196,988,939	$147,665,544	$152,024,845	$154,641,572	$166,843,579	$184,717,917	$193,350,252
Income Taxes	$128,308,484	$95,319,779	$18,702,731	$62,465,325	$5,552,610	$62,069,786	$65,183,994	$68,386,483	$71,638,558	$81,847,129	$85,265,827	$88,865,937
Implied Tax Rate	40.7%	24.5%	4.3%	18.8%	1.5%	14.1%	14.1%	14.1%	14.1%	14.1%	14.1%	14.1%
Property & Other Taxes	$59,251,457	$52,858,933	$57,985,528	$61,542,551	$64,208,273	$70,437,442	$73,971,477	$77,605,696	$81,296,185	$92,880,978	$96,760,552	$100,845,994
Percent of Rate Base	1.82%	1.57%	1.59%	1.62%	1.61%	1.64%	1.64%	1.64%	1.64%	1.64%	1.64%	1.64%
Return on Rate Base	$315,298,807	$388,396,940	$437,471,126	$332,612,524	$365,948,406	$438,842,918	$460,860,845	$483,502,940	$506,495,609	$578,671,773	$602,842,494	$628,295,820
Total System Revenue Requirement	$2,832,729,620	$3,626,267,850	$3,385,175,940	$2,360,701,423	$2,669,960,037	$2,843,838,610	$2,833,866,786	$2,848,314,576	$2,821,011,484	$2,963,683,804	$3,012,293,724	$3,115,596,520
Less:												
Other Revenue Sources	$14,693,072	$15,075,206	$15,488,651	$15,507,577	$15,448,898	$16,173,600	$16,580,400	$16,990,200	$17,393,400	$17,813,400	$18,260,400	$18,729,600
Wholesale Revenues	$1,256,997,695	$2,176,245,429	$1,850,796,812	$550,121,350	$866,791,614	$730,754,542	$722,699,138	$662,438,765	$570,958,492	$738,517,329	$648,804,455	$647,123,252
Net System Revenue Requirement	$1,561,038,853	$1,434,947,215	$1,518,890,477	$1,795,072,496	$1,787,719,525	$2,096,910,468	$2,094,587,248	$2,168,885,611	$2,232,659,592	$2,207,353,075	$2,345,228,869	$2,449,743,668
Wholesale Sales (MWh)					16,807,030	14,592,769	14,715,417	14,077,155	12,568,090	16,612,082	14,205,755	13,849,165
Xcel Retail Sales (MWH)	24,488,453	25,125,344	25,814,418	25,845,962	25,748,164	26,956,000	27,634,000	28,317,000	28,989,000	29,689,000	30,434,000	31,216,000
% Change		2.60%	2.74%	0.12%	-0.38%	4.69%	2.52%	2.47%	2.37%	2.41%	2.51%	2.57%
Average System Rate ($/MWH)	**$ 63.75**	**$ 57.11**	**$ 58.84**	**$ 69.45**	**$ 69.43**	**$ 77.79**	**$ 75.80**	**$ 76.59**	**$ 77.02**	**$ 74.35**	**$ 77.06**	**$ 78.48**
Rate Base						12	13	14	15	16	17	18
Gross Plant	$5,147,497,126	$5,425,763,828	$5,699,129,075	$5,947,581,812	$6,245,852,916	$6,709,575,136	$7,053,361,077	$7,407,043,423	$7,766,430,626	$8,617,439,467	$9,014,511,178	$9,431,635,829
ssion % Change		5.41%	5.04%	4.36%	5.01%	7.424%	5.124%	5.014%	4.852%	10.958%	4.608%	4.627%
Accum Depr	$1,885,836,107	$2,051,691,518	$2,059,252,753	$2,158,720,836	$2,246,397,502	$2,417,757,757	$2,546,211,698	$2,678,457,784	$2,812,980,155	$2,958,117,026	$3,118,802,746	$3,286,997,715
Net Plant	$3,261,661,019	$3,374,072,310	$3,639,876,322	$3,788,860,976	$3,999,455,414	$4,291,817,378	$4,507,149,379	$4,728,585,639	$4,953,450,471	$5,659,322,441	$5,895,708,432	$6,144,638,115
ssion % Change		$165,855,411				7.31%	5.02%	4.91%	4.76%	14.25%	4.18%	4.22%
Calc Return	9.67%	11.51%	12.02%	8.78%	9.15%	10.23%	10.23%	10.23%	10.23%	10.23%	10.23%	10.23%

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected
Revenue Requirement												
Operation and Maintenance Expense												
Production Cost												
Fixed -Non Fuel	$135,447,142	$138,553,169	$162,925,218	$167,302,574	$170,513,953	$175,017,279	$180,024,970	$182,704,497	$213,235,479	$218,824,806	$224,591,668	$230,162,527
Variable (Fuel)	$421,338,791	$430,193,278	$493,955,707	$514,966,681	$514,209,441	$535,172,907	$565,569,588	$543,750,601	$659,933,386	$685,040,335	$714,899,866	$722,984,549
Purchased Power (Split Out)	$1,194,885,064	$1,223,909,207	$1,255,406,043	$1,397,689,296	$1,441,594,811	$1,493,098,800	$1,546,397,713	$1,601,324,420	$1,665,350,471	$1,739,621,240	$1,808,568,182	$1,879,984,057
New Resource Capital												
Total Production Cost	$1,751,670,996	$1,792,655,654	$1,912,286,968	$2,079,958,551	$2,126,318,206	$2,203,288,986	$2,291,992,271	$2,327,779,519	$2,538,519,337	$2,643,486,380	$2,748,059,716	$2,833,131,133
Transmission Cost	$46,097,184	$48,469,587	$50,942,804	$53,534,250	$56,244,249	$59,068,104	$62,027,960	$65,164,473	$68,453,816	$71,888,542	$75,479,753	$79,250,263
Distribution Cost	$99,556,811	$104,680,529	$110,021,973	$115,618,761	$121,471,587	$127,570,312	$133,962,759	$140,736,736	$147,840,781	$155,258,814	$163,014,808	$171,158,037
Customer Service	$70,735,791	$74,376,227	$78,171,360	$82,147,916	$86,306,389	$90,639,574	$95,181,451	$99,994,408	$105,041,880	$110,312,442	$115,823,129	$121,608,949
A&G	$207,744,320	$218,435,937	$229,581,881	$241,260,650	$253,473,691	$266,199,846	$279,538,908	$293,674,107	$308,498,054	$323,977,198	$340,161,563	$357,153,967
Total Operation and Maintenance Expense	$2,175,805,102	$2,238,617,934	$2,381,004,985	$2,572,520,128	$2,643,814,122	$2,746,766,823	$2,862,703,348	$2,927,349,244	$3,168,353,867	$3,304,923,376	$3,442,538,968	$3,562,302,350
Total O&M Form 1												
Check												
Depreciation Expense	$176,723,715	$183,171,517	$193,352,350	$208,009,046	$213,915,548	$219,210,459	$225,900,771	$235,333,806	$248,614,510	$264,949,441	$271,887,159	$280,146,148
Amortization Expense	$26,430,844	$27,395,179	$28,917,827	$31,109,886	$31,993,264	$32,785,172	$33,785,777	$35,196,584	$37,182,850	$39,625,906	$40,663,513	$41,898,730
Total	$203,154,559	$210,566,696	$222,270,177	$239,118,932	$245,908,812	$251,995,631	$259,686,548	$270,530,390	$285,797,360	$304,575,347	$312,550,672	$322,044,877
Income Taxes	$92,672,568	$96,632,590	$108,415,505	$112,440,655	$116,604,821	$120,892,502	$125,338,411	$130,010,631	$143,791,704	$148,559,307	$153,490,089	$158,616,576
Implied Tax Rate	14.1%	14.1%	14.1%	14.1%	14.1%	14.1%	14.1%	14.1%	14.1%	14.1%	14.1%	14.1%
Property & Other Taxes	$105,165,798	$109,659,673	$123,031,048	$127,598,830	$132,324,370	$137,190,074	$142,235,339	$147,537,423	$163,176,329	$168,586,654	$174,182,157	$179,999,748
Percent of Rate Base	1.64%	1.64%	1.64%	1.64%	1.64%	1.64%	1.64%	1.64%	1.64%	1.64%	1.64%	1.64%
Return on Rate Base	$655,209,287	$683,207,251	$766,514,271	$794,972,699	$824,413,993	$854,728,553	$886,161,816	$919,195,126	$1,016,629,432	$1,050,337,117	$1,085,198,503	$1,121,443,551
Total System Revenue Requirement	$3,232,007,314	$3,338,684,144	$3,601,235,986	$3,846,651,245	$3,963,066,117	$4,111,573,583	$4,276,125,462	$4,394,622,814	$4,777,748,692	$4,976,981,801	$5,167,960,390	$5,344,407,102
Less:												
Other Revenue Sources	$19,225,200	$19,734,000	$20,247,600	$20,771,400	$21,303,600	$21,840,600	$22,389,000	$22,961,400	$23,546,400	$24,139,200	$24,741,600	$25,359,000
Wholesale Revenues	$657,170,874	$621,352,532	$832,030,614	$919,390,111	$862,711,066	$856,329,404	$876,418,792	$763,960,055	$1,108,780,832	$1,115,854,854	$1,100,162,459	$1,058,964,030
Net System Revenue Requirement	$2,555,611,240	$2,697,597,612	$2,748,957,772	$2,906,489,734	$3,079,051,451	$3,233,403,580	$3,377,317,670	$3,607,701,359	$3,645,421,460	$3,836,987,748	$4,043,056,331	$4,260,084,072
Wholesale Sales (MWh)	13,655,491	12,499,885	16,179,164	17,005,869	15,404,643	14,750,885	14,572,462	12,262,125	17,181,396	16,685,847	15,886,962	14,769,405
Xcel Retail Sales (MWH)	32,042,000	32,890,000	33,746,000	34,619,000	35,506,000	36,401,000	37,315,000	38,269,000	39,244,000	40,232,000	41,236,000	42,265,000
% Change	2.65%	2.65%	2.60%	2.59%	2.56%	2.52%	2.51%	2.56%	2.55%	2.52%	2.50%	2.50%
Average System Rate ($/MWH)	**$ 79.76**	**$ 82.02**	**$ 81.46**	**$ 83.96**	**$ 86.72**	**$ 88.83**	**$ 90.51**	**$ 94.27**	**$ 92.89**	**$ 95.37**	**$ 98.05**	**$ 100.79**
Rate Base	19	20	21	22	23	24	25	26	27	28	29	30
Gross Plant	$9,871,569,176	$10,328,556,550	$11,336,638,961	$11,822,967,125	$12,324,814,077	$12,840,496,353	$13,373,809,679	$13,932,204,266	$15,133,711,551	$15,728,317,055	$16,341,143,297	$16,975,760,535
ssion % Change	4.664%	4.629%	9.760%	4.290%	4.245%	4.184%	4.153%	4.175%	8.624%	3.929%	3.896%	3.884%
Accum Depr	$3,463,721,430	$3,646,892,947	$3,840,245,297	$4,048,254,343	$4,262,169,891	$4,481,380,349	$4,707,281,120	$4,942,614,926	$5,191,229,437	$5,456,178,877	$5,728,066,036	$6,008,212,184
Net Plant	$6,407,847,747	$6,681,663,603	$7,496,393,664	$7,774,712,782	$8,062,644,186	$8,359,116,004	$8,666,528,559	$8,989,589,340	$9,942,482,114	$10,272,138,177	$10,613,077,261	$10,967,548,351
ssion % Change	4.28%	4.27%	12.19%	3.71%	3.70%	3.68%	3.68%	3.73%	10.60%	3.32%	3.32%	3.34%
Calc Return	10.23%	10.23%	10.23%	10.23%	10.23%	10.23%	10.23%	10.23%	10.23%	10.23%	10.23%	10.23%

Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected
Revenue Requirement												
Operation and Maintenance Expense												
Production Cost												
Fixed -Non Fuel	$236,665,064	$271,126,289	$277,191,256	$284,146,466	$291,247,246	$330,033,288	$338,425,866	$346,958,748	$355,680,252	$399,457,614	$409,466,424	$419,630,099
Variable (Fuel)	$762,550,358	$886,738,350	$890,546,519	$916,473,709	$942,194,566	$1,075,003,790	$1,107,715,967	$1,139,719,025	$1,171,931,855	$1,323,332,339	$1,360,514,407	$1,396,098,804
Purchased Power (Split Out)	$1,953,946,775	$2,039,564,185	$2,237,097,372	$2,324,009,305	$2,423,276,285	$2,516,411,281	$2,612,688,479	$2,712,206,780	$2,825,452,336	$2,932,021,164	$3,042,152,525	$3,155,957,941
New Resource Capital												
Total Production Cost	$2,953,162,197	$3,197,428,824	$3,404,835,146	$3,524,629,480	$3,656,718,096	$3,921,448,359	$4,058,830,312	$4,198,884,553	$4,353,064,443	$4,654,811,117	$4,812,133,355	$4,971,686,845
Transmission Cost	$83,245,356	$87,485,464	$91,714,970	$96,106,157	$100,656,342	$105,374,912	$110,263,154	$115,319,889	$120,552,547	$125,961,938	$131,553,349	$137,332,213
Distribution Cost	$179,786,301	$188,943,729	$198,078,262	$207,561,975	$217,389,082	$227,579,852	$238,137,066	$249,058,175	$260,359,228	$272,041,975	$284,117,834	$296,598,538
Customer Service	$127,739,389	$134,245,804	$140,735,951	$147,474,194	$154,456,420	$161,697,032	$169,198,004	$176,957,526	$184,987,001	$193,287,673	$201,867,652	$210,735,277
A&G	$375,158,491	$394,267,215	$413,328,163	$433,117,744	$453,623,881	$474,888,871	$496,918,516	$519,707,498	$543,289,306	$567,667,592	$592,866,180	$618,909,554
Total Operation and Maintenance Expense	$3,719,091,734	$4,002,371,035	$4,248,692,493	$4,408,889,551	$4,582,843,821	$4,890,989,025	$5,073,347,052	$5,259,927,640	$5,462,252,525	$5,813,770,294	$6,022,538,371	$6,235,262,427
Total O&M Form 1												
Check												
Depreciation Expense	$291,312,737	$310,241,367	$314,795,485	$320,307,732	$325,258,041	$337,935,761	$355,228,172	$359,706,236	$364,310,709	$376,786,713	$394,644,754	$398,837,302
Amortization Expense	$43,568,808	$46,399,778	$47,080,893	$47,905,306	$48,645,676	$50,541,759	$53,128,016	$53,797,757	$54,486,403	$56,352,317	$59,023,170	$59,650,209
Total	$334,881,544	$356,641,146	$361,876,379	$368,213,038	$373,903,717	$388,477,519	$408,356,188	$413,503,993	$418,797,113	$433,139,031	$453,667,924	$458,487,511
Income Taxes	$164,010,391	$179,806,027	$185,059,479	$190,440,219	$195,934,371	$212,708,369	$218,150,232	$223,693,935	$229,342,624	$247,405,818	$252,931,279	$258,551,780
Implied Tax Rate	14.1%	14.1%	14.1%	14.1%	14.1%	14.1%	14.1%	14.1%	14.1%	14.1%	14.1%	14.1%
Property & Other Taxes	$186,120,705	$204,045,759	$210,007,431	$216,113,551	$222,348,372	$241,383,680	$247,559,163	$253,850,215	$260,260,407	$280,758,708	$287,029,058	$293,407,262
Percent of Rate Base	1.64%	1.64%	1.64%	1.64%	1.64%	1.64%	1.64%	1.64%	1.64%	1.64%	1.64%	1.64%
Return on Rate Base	$1,159,578,651	$1,271,256,227	$1,308,398,940	$1,346,441,596	$1,385,286,096	$1,503,880,832	$1,542,355,642	$1,581,550,476	$1,621,487,575	$1,749,197,129	$1,788,262,983	$1,828,000,795
Total System Revenue Requirement	$5,563,683,025	$6,014,120,195	$6,314,034,723	$6,530,097,955	$6,760,316,377	$7,237,439,425	$7,489,768,277	$7,732,526,260	$7,992,140,244	$8,524,270,979	$8,804,429,614	$9,073,709,776
Less:												
Other Revenue Sources	$26,003,400	$26,677,800	$27,300,600	$27,925,200	$28,549,200	$29,173,800	$29,797,800	$30,419,400	$31,039,200	$31,656,000	$32,269,800	$32,880,600
Wholesale Revenues	$1,072,166,347	$1,438,647,753	$1,457,755,198	$1,432,257,348	$1,408,883,169	$1,837,334,869	$1,821,244,867	$1,798,492,053	$1,777,210,458	$2,279,452,285	$2,261,364,916	$2,232,763,448
Net System Revenue Requirement	$4,465,513,278	$4,548,794,642	$4,828,978,925	$5,069,915,407	$5,322,884,008	$5,370,930,756	$5,638,725,610	$5,903,614,807	$6,183,890,586	$6,213,162,694	$6,510,794,898	$6,808,065,728
Wholesale Sales (MWh)	14,444,280	18,714,285	18,486,636	17,549,013	16,677,217	21,020,923	20,142,502	19,230,923	18,373,422	22,791,198	21,870,176	20,889,464
Xcel Retail Sales (MWH)	43,339,000	44,463,000	45,501,000	46,542,000	47,582,000	48,623,000	49,663,000	50,699,000	51,732,000	52,760,000	53,783,000	54,801,000
% Change	2.54%	2.59%	2.33%	2.29%	2.23%	2.19%	2.14%	2.09%	2.04%	1.99%	1.94%	1.89%
Average System Rate ($/MWH)	**$ 103.04**	**$ 102.31**	**$ 106.13**	**$ 108.93**	**$ 111.87**	**$ 110.46**	**$ 113.54**	**$ 116.44**	**$ 119.54**	**$ 117.76**	**$ 121.06**	**$ 124.23**
Rate Base	31	32	33	34	35	36	37	38	39	40	41	42
Gross Plant	$17,640,028,780	$19,042,459,959	$19,720,505,558	$20,412,864,713	$21,118,016,090	$22,615,790,439	$23,347,296,428	$24,090,322,215	$24,845,211,716	$26,470,978,550	$27,247,681,453	$28,035,148,548
sion % Change	3.913%	7.950%	3.561%	3.511%	3.454%	7.092%	3.234%	3.182%	3.134%	6.544%	2.934%	2.890%
Accum Depr	$6,299,524,920	$6,609,766,288	$6,924,561,773	$7,244,869,505	$7,570,127,546	$7,908,063,307	$8,263,291,478	$8,622,997,714	$8,987,308,424	$9,364,095,137	$9,758,739,891	$10,157,577,192
Net Plant	$11,340,503,860	$12,432,693,671	$12,795,943,785	$13,167,995,208	$13,547,888,544	$14,707,727,132	$15,084,004,949	$15,467,324,501	$15,857,903,292	$17,106,883,413	$17,488,941,563	$17,877,571,356
sion % Change	3.40%	9.63%	2.92%	2.91%	2.88%	8.56%	2.56%	2.54%	2.53%	7.88%	2.23%	2.22%
Calc Return	10.23%	10.23%	10.23%	10.23%	10.23%	10.23%	10.23%	10.23%	10.23%	10.23%	10.23%	10.23%

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Own Fuel Costs	$ 363,334,183	$ 351,140,723	$ 369,476,900	$ 371,322,626	$ 361,582,418	$ 405,470,778	$ 379,436,190	$ 399,357,059	$ 421,338,791	$ 430,193,278	$ 493,955,707	$ 514,966,681
Purchased Power Fuel	$ 846,004,561	$ 832,914,279	$ 795,150,645	$ 721,098,431	$ 664,922,217	$ 631,049,464	$ 592,308,445	$ 598,205,682	$ 608,929,882	$ 623,305,145	$ 639,786,880	$ 657,487,802
Own VOM&FOM	$ 94,240,344	$ 96,380,192	$ 99,472,772	$ 101,893,658	$ 104,256,616	$ 126,161,774	$ 127,888,168	$ 131,636,128	$ 135,447,142	$ 138,553,169	$ 162,925,218	$ 167,302,574
Purchased Power VOM&FOM	$ 482,039,002	$ 493,638,200	$ 505,541,325	$ 540,199,367	$ 527,705,309	$ 515,158,895	$ 559,160,554	$ 571,663,592	$ 585,955,182	$ 600,604,062	$ 615,619,163	$ 740,201,494
Capital costs						$ 119,339,154	$ 119,339,154	$ 119,339,154	$ 119,339,154	$ 119,339,154	$ 238,678,309	$ 238,678,309
Purchased Power Costs	$ 1,328,043,563	$ 1,326,552,479	$ 1,300,691,969	$ 1,261,297,799	$ 1,192,627,526	$ 1,146,208,359	$ 1,151,468,999	$ 1,169,869,274	$ 1,194,885,064	$ 1,223,909,207	$ 1,255,406,043	$ 1,397,689,296
Retail Sales	26,421,000	26,956,000	27,634,000	28,317,000	28,989,000	29,689,000	30,434,000	31,216,000	32,042,000	32,890,000	33,746,000	34,619,000
Wholesale Sales	15,885,808	14,592,769	14,715,417	14,077,155	12,568,090	16,612,082	14,205,755	13,849,165	13,655,491	12,499,885	16,179,164	17,005,869
Own Generation	23,669,085	23,080,766	24,103,990	24,023,309	23,707,627	29,144,225	27,586,685	28,078,439	28,737,112	28,416,689	33,140,938	33,579,945
Purchased Power	20,400,507	20,199,202	20,009,986	20,137,269	19,581,009	19,086,069	18,913,059	18,864,441	18,864,441	18,864,441	18,864,441	20,195,961
Losses	1,762,784	1,731,199	1,764,559	1,766,423	1,731,545	1,929,212	1,859,990	1,877,715	1,904,062	1,891,245	2,080,215	2,151,036
Losses %	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
Own Fuel Costs	$ 15.35	$ 15.21	$ 15.33	$ 15.46	$ 15.25	$ 13.91	$ 13.75	$ 14.22	$ 14.66	$ 15.14	$ 14.90	$ 15.34
Own All-in Cost	$ 19.33	$ 19.39	$ 19.46	$ 19.70	$ 19.65	$ 18.24	$ 18.39	$ 18.91	$ 19.38	$ 20.01	$ 19.82	$ 20.32
Purchased Power Cost	$ 65.10	$ 65.67	$ 65.00	$ 62.63	$ 60.91	$ 60.05	$ 60.88	$ 62.01	$ 63.34	$ 64.88	$ 66.55	$ 69.21
On-Peak Spot Market Price	$ 65.10	$ 65.67	$ 65.00	$ 62.63	$ 60.91	$ 60.05	$ 60.88	$ 62.01	$ 63.34	$ 64.88	$ 66.55	$ 69.21
Market Revenues	$ 1,034,143,172	$ 958,358,349	$ 956,533,621	$ 881,722,579	$ 765,489,184	$ 997,633,787	$ 864,877,863	$ 858,849,346	$ 864,947,004	$ 810,982,123	$ 1,076,704,051	$ 1,176,914,606
Rate	$ 48.01	$ 48.04	$ 46.73	$ 45.68	$ 44.01	$ 39.71	$ 40.30	$ 40.73	$ 41.17	$ 42.18	$ 40.71	$ 43.08

Inflation Rate	2.50%
Percent of Revenues into Rate	50%

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Market Price	$ 65.10	$ 65.67	$ 65.00	$ 62.63	$ 60.91	$ 60.05	$ 60.88	$ 62.01	$ 63.34	$ 64.88	$ 66.55	$ 69.21
Xcel Prod Cost	$ 42.21	$ 42.70	$ 41.79	$ 40.91	$ 39.91	$ 38.82	$ 39.83	$ 40.39	$ 40.94	$ 42.12	$ 43.08	$ 44.91
Xcel Prod Cost plus Historical Margin	$ 48.96	$ 49.53	$ 48.47	$ 47.46	$ 46.29	$ 45.03	$ 46.21	$ 46.85	$ 47.49	$ 48.86	$ 49.98	$ 52.10

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Own Fuel Costs	$ 514,209,441	$ 535,172,907	$ 565,569,588	$ 543,750,601	$ 659,933,386	$ 685,040,335	$ 714,899,866	$ 722,984,549	$ 762,550,358	$ 886,738,350	$ 890,546,519	$ 916,473,709
Purchased Power Fuel	$ 675,893,177	$ 701,202,369	$ 727,354,641	$ 754,272,311	$ 789,400,774	$ 825,944,166	$ 863,937,007	$ 903,422,124	$ 944,447,940	$ 987,356,028	$ 1,147,344,563	$ 1,197,834,495
Own VOM&FOM	$ 170,513,953	$ 175,017,279	$ 180,024,970	$ 182,704,497	$ 213,235,479	$ 218,824,806	$ 224,591,668	$ 230,162,527	$ 236,665,064	$ 271,126,289	$ 277,191,256	$ 284,146,466
Purchased Power VOM&FOM	$ 765,701,634	$ 791,896,431	$ 819,043,072	$ 847,052,109	$ 875,949,697	$ 913,677,073	$ 944,631,175	$ 976,561,934	$ 1,009,498,836	$ 1,052,208,157	$ 1,089,752,808	$ 1,126,174,810
Capital costs	$ 238,678,309	$ 238,678,309	$ 238,678,309	$ 238,678,309	$ 358,017,463	$ 358,017,463	$ 358,017,463	$ 358,017,463	$ 358,017,463	$ 477,356,617	$ 477,356,617	$ 477,356,617
Purchased Power Costs	$ 1,441,594,811	$ 1,493,098,800	$ 1,546,397,713	$ 1,601,324,420	$ 1,665,350,471	$ 1,739,621,240	$ 1,808,568,182	$ 1,879,984,057	$ 1,953,946,775	$ 2,039,564,185	$ 2,237,097,372	$ 2,324,009,305
Retail Sales	35,506,000	36,401,000	37,315,000	38,269,000	39,244,000	40,232,000	41,236,000	42,265,000	43,339,000	44,463,000	45,501,000	46,542,000
Wholesale Sales	15,404,643	14,750,885	14,572,462	12,262,125	17,181,396	16,685,847	15,886,962	14,769,405	14,444,280	18,714,285	18,486,636	17,549,013
Own Generation	32,752,739	32,934,128	33,617,134	32,121,063	38,177,708	38,524,238	38,654,679	38,479,213	39,176,071	44,628,386	44,166,386	44,190,851
Purchased Power	20,279,181	20,349,086	20,432,306	20,515,526	20,598,746	20,765,186	20,848,406	20,931,626	21,014,846	21,181,286	22,487,402	22,570,622
Losses	2,121,277	2,131,329	2,161,978	2,105,464	2,351,058	2,371,577	2,380,123	2,376,434	2,407,637	2,632,387	2,666,152	2,670,459
Losses %	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
Own Fuel Costs	$ 15.70	$ 16.25	$ 16.82	$ 16.93	$ 17.29	$ 17.78	$ 18.49	$ 18.79	$ 19.46	$ 19.87	$ 20.16	$ 20.74
Own All-in Cost	$ 20.91	$ 21.56	$ 22.18	$ 22.62	$ 22.87	$ 23.46	$ 24.30	$ 24.77	$ 25.51	$ 25.94	$ 26.44	$ 27.17
Purchased Power Cost	$ 71.09	$ 73.37	$ 75.68	$ 78.05	$ 80.85	$ 83.78	$ 86.75	$ 89.82	$ 92.98	$ 96.29	$ 99.48	$ 102.97
On-Peak Spot Market Price	$ 71.09	$ 73.37	$ 75.68	$ 78.05	$ 80.85	$ 83.78	$ 86.75	$ 89.82	$ 92.98	$ 96.29	$ 99.48	$ 102.97
Market Revenues	$ 1,095,076,431	$ 1,082,335,030	$ 1,102,901,590	$ 957,111,244	$ 1,389,067,392	$ 1,397,871,148	$ 1,378,170,271	$ 1,326,521,231	$ 1,343,019,809	$ 1,802,014,544	$ 1,839,092,196	$ 1,806,953,792
Rate	$ 44.47	$ 45.66	$ 46.64	$ 48.32	$ 46.99	$ 48.33	$ 49.93	$ 51.34	$ 52.65	$ 51.65	$ 54.62	$ 56.32
Inflation Rate												
Percent of Revenues into Rate												
Market Price	$ 71.09	$ 73.37	$ 75.68	$ 78.05	$ 80.85	$ 83.78	$ 86.75	$ 89.82	$ 92.98	$ 96.29	$ 99.48	$ 102.97
Xcel Prod Cost	$ 46.45	$ 47.74	$ 48.77	$ 50.79	$ 51.33	$ 52.73	$ 54.38	$ 55.95	$ 57.30	$ 58.17	$ 60.67	$ 62.44
Xcel Prod Cost plus Historical Margin	$ 53.89	$ 55.38	$ 56.58	$ 58.92	$ 59.55	$ 61.17	$ 63.08	$ 64.90	$ 66.47	$ 67.47	$ 70.38	$ 72.43

	2028	2029	2030	2031	2032	2033	2034	2035
Own Fuel Costs	$ 942,194,566	$ 1,075,003,790	$ 1,107,715,967	$ 1,139,719,025	$ 1,171,931,855	$ 1,323,332,339	$ 1,360,514,407	$ 1,396,098,804
Purchased Power Fuel	$ 1,250,131,833	$ 1,304,295,391	$ 1,360,385,795	$ 1,418,465,534	$ 1,478,599,019	$ 1,540,852,637	$ 1,605,294,812	$ 1,671,996,063
Own VOM&FOM	$ 291,247,246	$ 330,033,288	$ 338,425,866	$ 346,958,748	$ 355,680,252	$ 399,457,614	$ 409,466,424	$ 419,630,099
Purchased Power VOM&FOM	$ 1,173,144,452	$ 1,212,115,890	$ 1,252,302,685	$ 1,293,741,247	$ 1,346,853,317	$ 1,391,168,527	$ 1,436,857,713	$ 1,483,961,879
Capital costs	$ 477,356,617	$ 596,695,771	$ 596,695,771	$ 596,695,771	$ 596,695,771	$ 716,034,926	$ 716,034,926	$ 716,034,926
Purchased Power Costs	$ 2,423,276,285	$ 2,516,411,281	$ 2,612,688,479	$ 2,712,206,780	$ 2,825,452,336	$ 2,932,021,164	$ 3,042,152,525	$ 3,155,957,941
Retail Sales	47,582,000	48,623,000	49,663,000	50,699,000	51,732,000	52,760,000	53,783,000	54,801,000
Wholesale Sales	16,677,217	21,020,923	20,142,502	19,230,923	18,373,422	22,791,198	21,870,176	20,889,464
Own Generation	44,199,623	49,725,472	49,810,563	49,856,948	49,873,319	55,462,783	55,485,790	55,441,412
Purchased Power	22,737,062	22,820,282	22,903,502	22,986,722	23,153,162	23,236,382	23,319,602	23,402,822
Losses	2,677,467	2,901,830	2,908,563	2,913,747	2,921,059	3,147,967	3,152,216	3,153,769
Losses %	4%	4%	4%	4%	4%	4%	4%	4%
Own Fuel Costs	$ 21.32	$ 21.62	$ 22.24	$ 22.86	$ 23.50	$ 23.86	$ 24.52	$ 25.18
Own All-in Cost	$ 27.91	$ 28.26	$ 29.03	$ 29.82	$ 30.63	$ 31.06	$ 31.90	$ 32.75
Purchased Power Cost	$ 106.58	$ 110.27	$ 114.07	$ 117.99	$ 122.03	$ 126.18	$ 130.45	$ 134.85
On-Peak Spot Market Price	$ 106.58	$ 110.27	$ 114.07	$ 117.99	$ 122.03	$ 126.18	$ 130.45	$ 134.85
Market Revenues	$ 1,777,428,656	$ 2,317,994,549	$ 2,297,730,846	$ 2,269,059,520	$ 2,242,165,776	$ 2,875,846,858	$ 2,853,068,087	$ 2,817,022,312
Rate	$ 58.17	$ 56.81	$ 58.59	$ 60.44	$ 62.48	$ 60.97	$ 62.95	$ 65.02
Inflation Rate								
Percent of Revenues into Rate								
Market Price	$ 106.58	$ 110.27	$ 114.07	$ 117.99	$ 122.03	$ 126.18	$ 130.45	$ 134.85
Xcel Prod Cost	$ 64.33	$ 64.87	$ 66.69	$ 68.58	$ 70.60	$ 71.09	$ 73.07	$ 75.14
Xcel Prod Cost plus Historical Margin	$ 74.63	$ 75.25	$ 77.36	$ 79.55	$ 81.90	$ 82.46	$ 84.76	$ 87.17