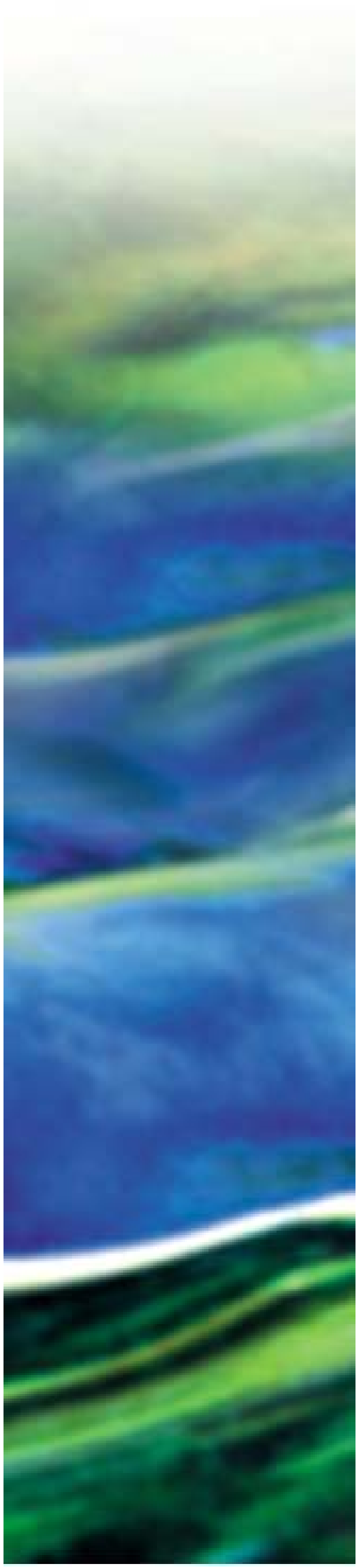

Boulder Municipal Utility

Feasibility Study

Prepared for:

City of Boulder

Prepared by:

RBI Robertson - Bryan, Inc.
Solutions for Progress

August16, 2011

Executive Summary

The City of Boulder, CO is studying various alternatives for its electricity supply that would improve its rate stability, reliability of service, and carbon emissions reductions. The City is examining the feasibility of creating a municipal electric utility as one option. The creation of a municipal utility for the City of Boulder ("City") is legally, physically, and financially feasible, and that entity would be capable of meeting the City's core objectives related to rate stability, reliability, and decarbonization.

- The creation of the municipal utility is legally feasible based on compliance with federal, state and local legislation.
    - Through municipalization, the City would change from retail customer to wholesale customer of XCEL Energy.
    - XCEL Energy may still litigate over stranded costs and distribution acquisition costs.
    - Negotiations or possible litigation with XCEL would precede the creation of the municipal utility, therefore it is not considered part of this feasibility study.
- The municipal utility is physically feasible:
    - Creating a municipal utility would not affect the existing transmission grid because the City's load is already served by the capacity available on the existing transmission grid. It would open new alternatives to connect to the Western Area Power Administration (WAPA) and the Tri-State Generation & Transmission transmission grids.
    - Creating a municipal utility would not affect the resource capacity already serving the City. It would open new possibilities to procure power from network resources, independent power producers, renewable generation and the wholesale market.
    - The Regional Transmission Operator, Xcel, would be legally required to continue to provide transmission and ancillary services to the City under Open Access.
    - The City would need to consider either annexing neighboring areas or severing the distribution grid connections with ratepayers located outside the City.
    - Utility operations could ramp up with contractors, under the utility Board direction. The City could then gradually take on the utility operations.
- The creation of a municipal utility is financially feasible:
    - This finding is based in part on the following assumptions:
        - **No stranded costs.** Stranded cost obligations would ultimately be settled by negotiation or litigation and are therefore too speculative for inclusion in the feasibility study.
        - **No acquisition costs for SmartGridCity™.** As of the time of the report, the City has not made a determination regarding which, if any, of the SmartGridCity™ assets should be acquired. The City probably does not require the SmartGridCity™ infrastructure to start a municipal utility; therefore, the decision to acquire all or parts of the system can be made at a later time.

- Based on these assumptions, we have projected start-up costs for the municipal utility at $223 million (see Table ES-1).
- Financing the start-up costs entails two bonds, each with a 30-year term:
  - Taxable bond to fund $177 million at 8 percent
    - Taxable bond par amount: $230 million
    - The study assumes the $41.3 million operating reserve is held in the taxable bond and $10 million in capital spare reserve is held in the tax-exempt bond, without reduction. This is intended to add a conservative factor to the financial feasibility.
  - Non-taxable bond to fund $45.5 million at 5.76 percent
    - Non-taxable bond par amount: $56.6 million
- Other bond parameters include:
  - 2 interest payments per year
  - Debt service reserve: 10 percent
  - Capitalized interest: 1.5 years
  - Annual interest income: 1.50 percent
  - The debt service coverage ratio averages 1.72 over initial 10 years of bond repayment.
- Once the municipal utility begins generating revenue, it can collect as much as $6.5 million annually, reaching $12.6 million annually by 2020, from two sources:
  - Public Purpose Program fund (P^3 fund): 5 percent of operating cost
    - The P^3 fund will bring between $3.6 and 7 million annually for energy efficiency programs.
  - Payment In Lieu Of Taxes (PILOT): 4 percent of operating cost
    - PILOT will bring between $3 and 5.6 million annual for the City general fund.

Municipal Utility Start-Up Cost Categories	Start-Up Costs (in millions)
Acquisition of the Distribution Assets	$121.2
5-month Reserve for Energy and Transmission	$29.5
1-Year Reserve for Utility Operations	$11.8
Distribution System Severance	$15
Logistics Setup	$32.5
Legal and Engineering (excl. Litigation)	$3
Capital Spares	$10
Total	$223

Table ES-1: Municipal Utility Start-Up Costs

- The City's core objectives can be met with a municipal utility:
  - **Rate stability**: In the 10 years prior to reaching the break-even point, the municipal utility would be able to stabilize its rates to an average 4 percent annual increase by offsetting the initial 3 year revenues over the next 7 years. After bond repayment, the municipal utility's revenue requirement is projected to decrease by over $30 million annually; in addition, the utility would recover $28 million held as Debt Service Reserve.
  - **Reliability of service**: Creating a municipal utility opens possibilities for procurement of resources, distribution system upgrades and alternative transmission grids not otherwise made available by the incumbent utility. The City can also create alliances with neighboring utilities for capital spare management and maintenance of the distribution system.
  - **Reduction of carbon emissions**: The incumbent utility plans to decrease its CO_2 emissions by 23 percent under the Clean Air–Clean Jobs Act (HB 10-1365). This entails a carbon reduction from 1,470 to 1,130 lb CO_2 per MWh. The City would need to reduce its dependency on coal to lower its carbon emissions further; this may require that the City's electrical resources be independent from the incumbent utility.

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1 Introduction

The City of Boulder (City) has three core objectives for electricity service:

- Rate stability
- Reliability of service
- Reduction of carbon emission

To achieve those objectives, the City is examining the possibility of creating a municipal electric utility as an alternative to remaining a retail customer of the incumbent Investor-Owned Utility (IOU), Xcel Energy (Xcel). The City contracted Robertson-Bryan, Inc. (RBI) to develop the feasibility study for a municipal utility, including the inventory and valuation of assets, determination of the wholesale power supply options, derivation of the total operating cost, City revenue requirements and rate impact analysis.

The financial feasibility study is derived from a 10-year energy and cost model developed by RBI to investigate the impact of numerous variables. The energy model calculates hourly load, resources and balancing trades with the wholesale market, then aggregates the on-peak and off-peak results at the monthly level. The cost model has a monthly level of granularity and calculates all the costs associated with energy, transmission, operations, financing, etc.

The study looks briefly at the legal and physical feasibilities, and summarizes the findings pertaining to the City's core objectives. The bulk of the study rests on the financial feasibility.

2 Legal Feasibility

The creation of a municipal utility appears to be consistent with federal, state, and local laws. Legal analysis was completed by the City and was not included in the scope of this study

Federal. The Federal Energy Regulatory Commission (FERC) supports the creation of publicly owned electric utilities, including municipal utilities, to encourage competition and lower costs of service to rate payers. FERC's Open Access policy, issued in 1996, requires that Regional Transmission Operators (RTOs) and Balancing Area Controllers, such as Western Area Power Administration (WAPA), Xcel and Tri-State, make their transmission grid and ancillary services available to their wholesale customers, under the same availability and rate conditions as they apply to themselves.[1] Therefore the municipal utility is assured to receive wholesale transmission, energy and ancillary services at a non-discriminating rate.[2]

State. The State's Constitution allows Home Rule Cities to create their own utilities and the City's charter includes provisions to create an electric utility.

[1] See Attachment D: OATT Report.

[2] See Federal Power Act (FPA) sections 201, 211 and 212.

Local. The municipal utility would operate on a cost basis, which is fundamentally different from IOU rates, which are based on profit. Therefore the Colorado Public Utility Commission would not have jurisdiction over the municipal utility's rate setting and policies.

Accordingly, the creation of a municipal utility is compliant with federal, state and local legislations. However, the City should be aware of two potential legal issues:

- Possible litigation with the IOU over acquisition and stranded costs.
- Compliance with requirements of the North American Electric Reliability Corporation (NERC) as part of the municipal utility operations.

In summary, FERC and NERC regulate the utility's use of wholesale transmission, ancillary services, and generation at the federal level. Under FERC policies, the City is guaranteed wholesale electric service for resource wheeling, load balancing and ancillary services. Under state and local law, a municipal utility would dictate its own rates and policies within its distribution territory.

3 Physical Feasibility

This section reviews physical concerns with regard to distribution, transmission, operation, ancillary services and generation resources.

3.1 Distribution System

The distribution system includes substations, above-ground and underground power lines, street lights, pole- and ground-mounted transformers, meters, easements, yards, service tools and spare supplies. The distribution system was developed, maintained and upgraded over time and does not present any concern; it is sized to handle the current load with significant capacity margin.[3]

The feasibility study assumes the purchase of the entire distribution system from the incumbent utility, excluding any SmartGridCity™ assets. Several valuations of the distribution infrastructure have been derived, including book value and Replacement Cost New Less Depreciation (RCNLD).[4] The City's electric distribution network may include several feeders serving customers outside City limits; electrical drawings showing the distribution circuits were not available at the time of this study and it is recommended to determine the severance plan after the City acquires the distribution drawings and specifications.

An annual budget was developed for staffing, system upgrade, line undergrounding, maintenance and operation under current standards. The start-up budget includes capital spare parts.

[3] Cf. 2011 Baseline Analysis from NEXANT et al.
[4] See RW Beck studies (Oct. 2005, updated in Feb. 2008), and RBI Inventory and Valuation of Assets (Apr. 2011).

The distribution operation and maintenance budget provides a cost guideline against which the City can measure such alternatives as:

- Having a contractor operate and maintain the system during the utility start-up.
- Developing an alliance with neighboring utilities such as the City of Longmont, the City of Lyons, the City of Fort Collins, the City of Colorado Springs, Platte River Power Authority, Tri-State, etc.
- Having an on-call contractor.
- Contracting the IOU to continue the maintenance, upgrade and operation of the distribution system
- Hiring staff and management from the IOU as part of the distribution system purchase agreement.

Furthermore, in accordance with the City's goals, the distribution system may need to evolve to facilitate energy localization efforts, including demand-side management, PV solar, distributed generation, energy storage, and plug-in electric vehicles.

3.2 Utility Operations

The responsibilities of the proposed municipal utility would include operation and maintenance of the distribution infrastructure, meter reading, billing, energy scheduling, risk planning, regulatory compliance and reports, power procurement, and accounting.

The initial utility operation, as a Load Serving Entity (LSE), does not present any unique challenge[5]. The City already successfully operates several utilities. Because it could take several years to fully take on the electrical utility operation should the City choose to municipalize, the City could contract with third parties to assist with initial operations, including:

- Meter reading, which entails Validation, Estimation and Editing (VEE) to ensure clean and complete data. This task can be contracted to a Meter Data Management Agency (MDMA).
- Regulatory compliance can be carried under the supervision of a qualified law firm.
- All other operation functions above can be handled by third party contractors, under the direction of the utility's General Manager.

The time frame to set-up the utility is estimated to be between 18 and 24 months from creation to commencing operations.[6] The use of experienced contractors, in conjunction with the City's existing resources and under the direction of a General Manager, would improve the efficiency of the start-up.

[5] There are 29 municipal utilities and 26 rural electric cooperatives in addition to the 2 Investor-Owned Utilities in the State of Colorado (ref.: GEO's 2010 Colorado Utilities Report).
[6] See Business Plan report from RBI. Excludes FERC filing, discovery and negotiations with incumbent utility.

The electric utility would need 2 to 4 years of steady-state operations before implementing non-conventional solutions for carbon-reduction.

The City should be mindful of the following potential pitfalls if it chooses to municipalize:

- Taking on electricity or gas interstate transmission.[7] This is a significant step in the operation of a utility, which may prove attractive in the future but should not be considered until the municipal utility operates smoothly for several years as an LSE.
- Taking on Ancillary Services at the transmission level, such as generator dispatch, voltage and frequency control, etc. These tasks are highly specialized, require extensive NERC training and compliance, and should be left to the RTO.

3.3 Transmission

The transmission system consists of high-voltage power lines connecting the electric generators to the distribution substations. The City is currently served by Xcel's 230,000 Volt and 115,000 Volt transmission grids. The City's load represents only 3.8 percent of the total system load[8] and the creation of a municipal utility would not result in any significant load increase.

There are two points of capacity constraint (TOT-3 and TOT-7[9]) beyond which the City's energy imports or exports could be curtailed.

TOT-3 is a 1,600 MW capacity constraint between southeast Wyoming and Northeast Colorado, which could impede the import of wind energy from the Cheyenne-Laramie-Sydney area. TOT-3 affects mainly transmission owned and operated by WAPA, Basin Electric Power Cooperative and Tri-State. Further studies of capacity available to Boulder via the Poudre Valley REA transmission should be undertaken should the city decide to create a municipal utility.

TOT-7 is a 900 MW capacity constraint northwest of Boulder. It affects the ability to wheel in wind energy from the north-east plains to Fort St Vrain, either on the Xcel 230 kV line from Pawnee, or on the WAPA 115 kV line from Story. The WAPA 115 kV line going from Story to Hoyt, Brighton and Longmont does not seem subject to the TOT-7 constraint. A capacity study will be needed to confirm the availability of wind energy from designated resources should the City decide to create a municipal utility.

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[7] Including the generator tie from Sunshine Canyon to the Boulder Terminal substation, serving the City-owned hydropower.
[8] According to the PSCo Loads and Resources Balance Summer 2010-2015, April 2010 Demand Forecast, the firm obligation load was 6,128 MW in 2010. City of Boulder's peak demand was 235 MW.
[9] TOT stands for Total Of Transmission

Colorado Transmission Constraints

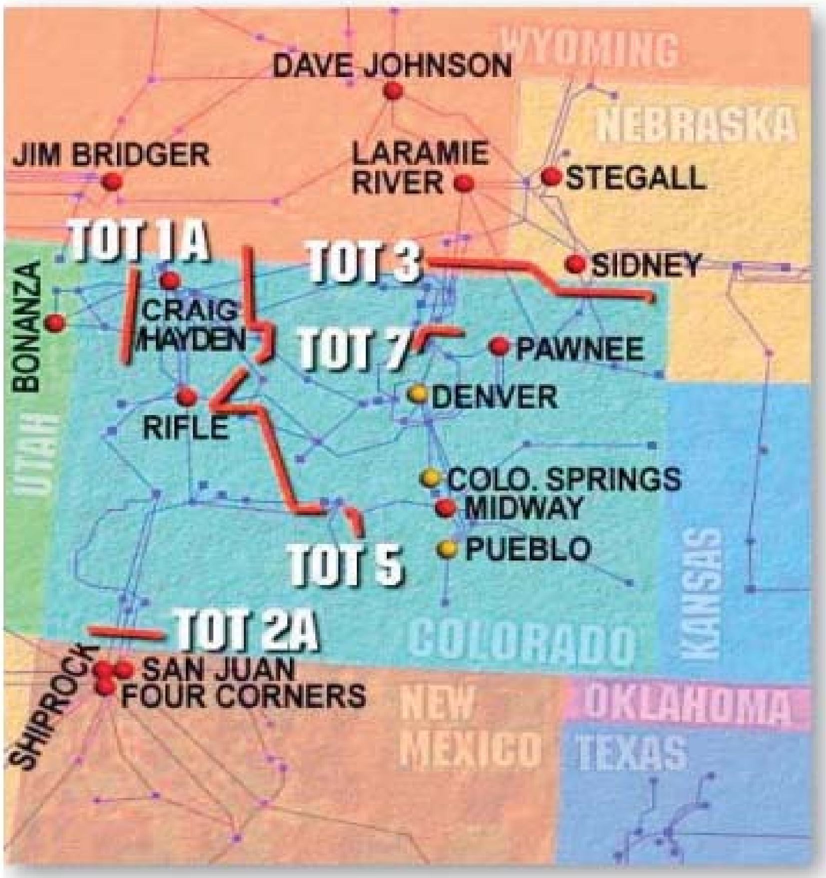


Figure 1: Colorado Transmission Constraints

Independent of the transmission constraints identified above, the municipal utility would likely rely on wholesale market energy and network-integrated generation for most of its purchases during initial operation. The municipal utility would enter into a wholesale agreement with the RTO for the use of the transmission system to wheel energy from remote and non-designated resources. This type of agreement is driven by FERC's Open Access Transmission Tariff (OATT) policy. Two other alternative transmission grids may be available to the City:

- A 115,000-volt transmission line operated by WAPA.[10]
- A 230,000-volt transmission line operated by Tri-State Generation and Transmission.

In summary, a municipal utility would not impact the existing transmission system and it is uniquely positioned at the juncture of two other transmission systems to chose a transmission alternative if

[10] WAPA: Western Area Power Administration. Although the City is not currently a WAPA customer, it could benefit from the WAPA OATT for the wheeling of independent energy resources.

necessary. This feasibility study remains focused on the existing infrastructure operated by the incumbent utility, yet the City may want to further investigate interconnection and OATT costs with WAPA and Tri-State.

3.4 Ancillary Services

Ancillary services (A/S) ensure the operation and reliability of the transmission grid. A/S include generator dispatch, voltage and frequency control, capacity reserve, etc. These services are provided by the transmission operator. The municipal utility would contract with the Balancing Area Controller,[11] for ancillary services under OATT, as part of the transmission service.

3.5 Resources

Resources consist of the generators that provide energy and capacity reserve to the City, whether from designated power plants or indirectly through market wholesale purchases. It is feasible to obtain these resources because there is enough existing generation capacity to handle the City's current load. Furthermore, the municipal utility will have access to alternative resources such as:

- Independent Power Producers for natural gas and renewable generation
- Wholesale Market suppliers, including but not limited to the IOU
- City-owned resources, such as distributed generation and network-integrated power plants located on the transmission grid.

Although the incumbent utility will be resource-short after 2016,[12] it has declined to renew power purchase agreements (PPAs) with existing independent power producers. The sunsetting of those PPAs will result in over 300 MW of stranded gas generation that the City could contract with, including 80 MW located at the Valmont Plant. Capacity resource currently exceeds the demand however it is expected to fall short after 2016; the municipal utility would capitalize initially on excess third party generation capacity but should consider owning generation in time to mitigate the cost increase after 2016.

4 City's Core Objectives

The municipal utility aims at the following core objectives (the three R's):

- Rate stability
- Reduction of carbon emissions (Renewables)
- Reliability of service

[11] There are 3 Balancing Area Controllers in Colorado: WAPA, Tri-State and Xcel.
[12] According to the PSCo Loads and Resources Balance Summer 2010-2015, April 2010 Demand Forecast, PSCo had in 2010 4,560 MW of Installed Net Dependable Capacity to serve a Firm Obligation Load of 6,128 MW plus 16.3 percent of reserve margin. The balance of resources entailed 3,280 MW of Firm Purchased Capacity including 561 MW of wholesale imports.

Because renewable resources can be acquired from diverse sources and in diverse ways, this study focuses primarily on the goals of rate stability and reliability of service. While the study looks at a 10 year range under the given scenario, it is probable that the municipal utility would engage in localization efforts and diversification of its resource portfolio within 3 to 5 years of its inception, if not sooner. Hence the 10 year report based on conventional energy should not be construed as a status-quo but rather as a start-up study with an eye out to recognize cost trends.

The municipal utility presumably would rely on the following resources during its start-up phase:

- Local hydroelectric power (12 MW installed, 5.5 MW average annual generation)
- Balancing resources: wholesale market energy

This study does not include the 9 MW of PV solar located within the City's boundaries because it is unknown whether the incumbent utility would agree to transfer the 9 MW of renewable resources financed by its ratepayers under the Renewable Energy Standard Adjustment (RESA). Accordingly, this study does not include any financial expenditure to purchase the rebates and/or RECs provided to those PV systems.[13] It is assumed the City would develop its own renewable energy program, the acquisition of the existing Solar*Reward Program is not considered part of the electric utility start-up in this study.

4.1 Rate Stability

Rate stability for the municipal utility is measured against the incumbent utility's composite retail rate forecast for the City (see Figure 2).[14] The incumbent utility's rates derivation is based on:

- Clean Air–Clean Jobs Act rate forecast
- No Carbon Tax
- Composite retail rate lower than the IOU's average composite retail rate, given that Boulder has a higher than average proportion of commercial accounts.

The municipal utility's costs would start without debt service payment for two years. Debt service payment would start at year 3, at which time the municipal utility may face a 28 percent cost increase, as seen by the blue line below in Figure 2. To mitigate a corresponding rate increase in year 3, the municipal utility could set its initial rate 7 percent below the IOU's during the first 2 years, and limit the annual rate increase to 4 percent over the next 7 years.

[13] Renewable Energy Credits. Reference: Western Renewable Energy Generation Information System (WREGIS).
[14] See Baseline Analysis report and Clean Air Clean Job Act rate derivation, NEXANT et al.

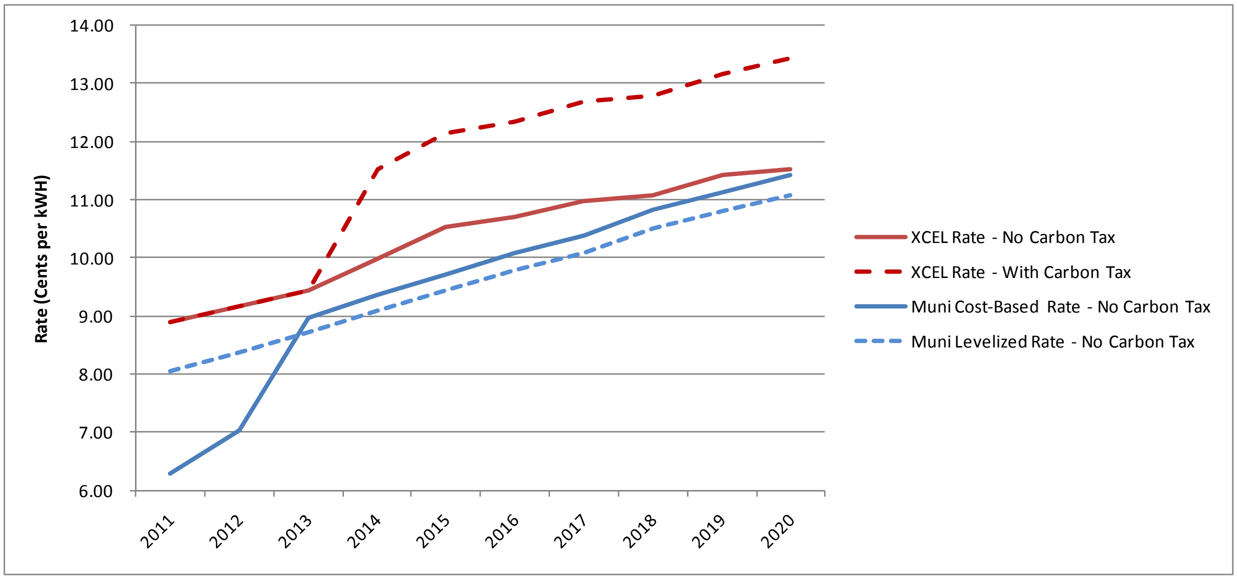


Figure 2: Rate Parity with Rate Control Strategy

In the event of a carbon tax, the IOU's rates are expected to rise by nearly 20 percent as shown with the dashed line on Figure 2 above. Should the Federal Government implement a carbon tax, Xcel would need to increase its rates significantly because of its reliance on coal generation. As a cautionary word, energy costs would likely increase all around as a result of the carbon tax, and the municipal utility's costs would increase as well.

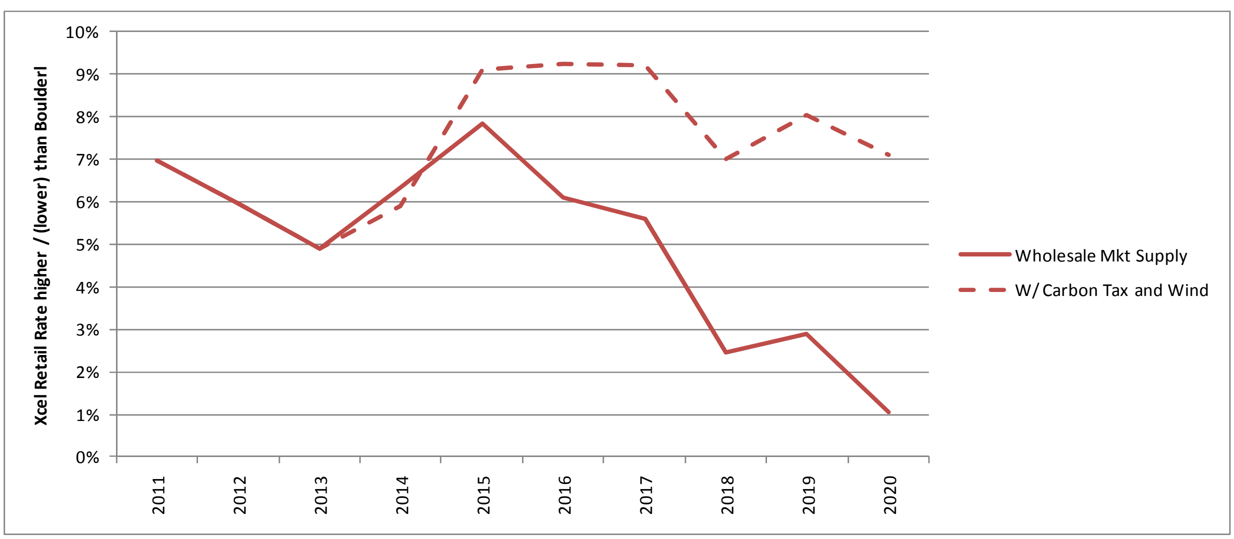


Figure 3: Incumbent Utility's Rate Parity Compared to the Municipal Utility

In Figure 3 above, the solid line shows that the incumbent IOU's retail rate would be up to 8 percent higher than the municipal utility's rate under wholesale market supply. In the event of a carbon tax, lesser dependence on coal generation could mitigate the municipal utility's rate increase compared to the incumbent's projected rate increase. For example, the municipal utility could bring its rates lower than the incumbent IOU by developing 48 MW of wind, as shown by the dashed line.

In summary, the municipal utility's rates are modeled to start slightly below the incumbent IOU's, and are projected to remain advantageous over the incumbent IOU's rates for the next 10 years. This analysis is based on conventional market resources; however, the municipal utility would likely be able to implement carbon reduction strategies that could further shield rates from the volatility of fossil fuel prices[15] and carbon tax.

4.2 Carbon Reduction

Three percent of the City's load would be met with City-owned hydroelectric power. The remaining 97 percent would be initially procured from the wholesale market. The carbon footprint of wholesale energy delivered to Boulder from non-designated resources is that of the incumbent IOU,[16] and the hydroelectric resource would give the City a 3 percent advantage over the incumbent utility's renewable portfolio.

However, this assumption of reliance on the wholesale market does not conform to a long-term vision which views the municipal utility as an opportunity to develop renewable resources. While the purpose of this study was to research feasibility as a "base case"—operating a local utility similar to current operations—the cost model was used to research a few hypothetical scenarios for the purpose of seeing the impacts of increased renewable energy on carbon reduction. Accordingly, the following discussion compares three scenarios of renewable resources:

- Scenario #1 is the case study, with wholesale market energy to supply 97 percent of the load, the other 3 percent being served by the City-owned hydroelectric.
- Under Scenario #2, the City would replace 100 MW of its market supply with wind energy, firmed with natural gas generation. The wind generation has a conservative capacity factor of 30 percent.
- Scenario #3 involves developing local PV-Solar gradually to 45 MW by 2020, in addition to the 100 MW of firm wind. The PV-solar generation was modeled with a 17 percent capacity factor, as if it were a single fixed array. In reality, the aggregation and diversity of array orientations would likely yield a higher capacity factor.

[15] See also localization strategies developed by Local Power, Inc.
[16] See 4 C.C.R. 723-3 § 3406, Component and Source Disclosures,

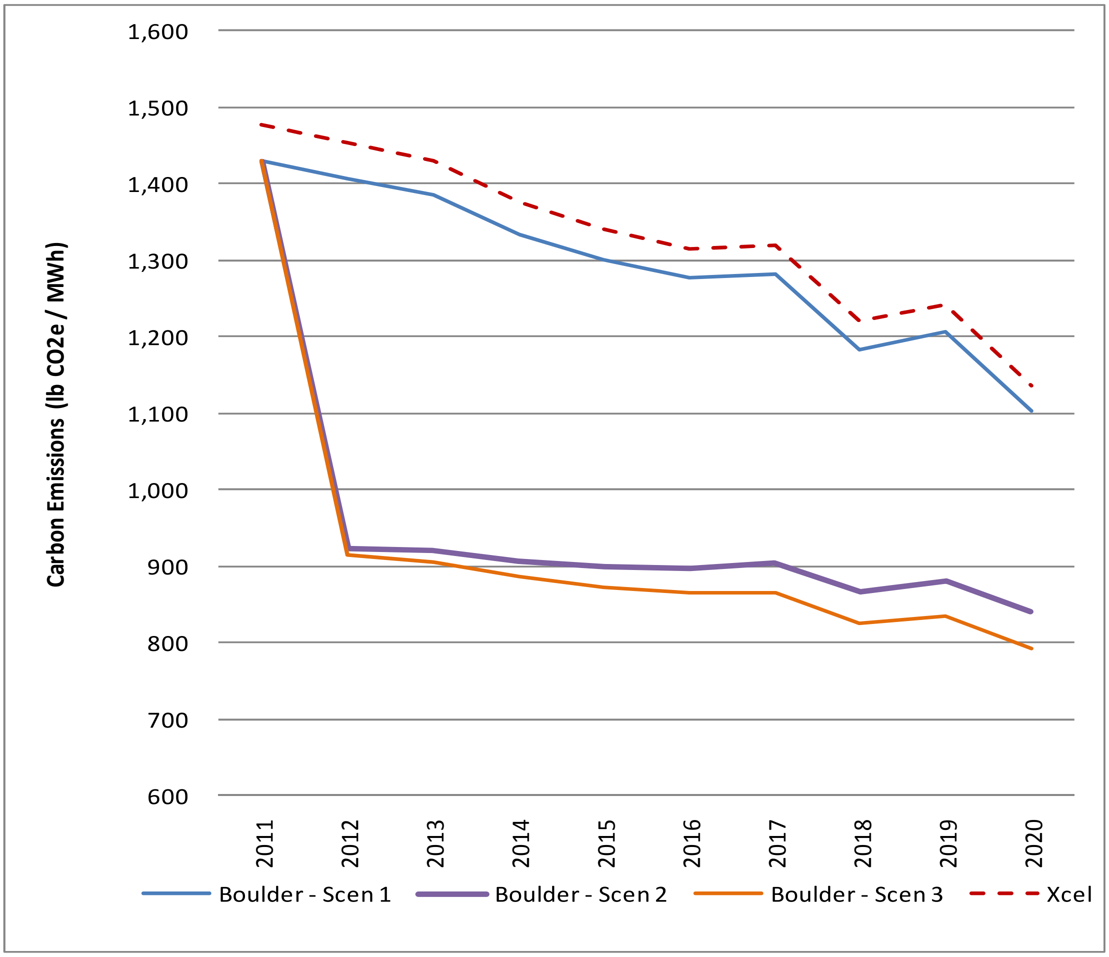


Figure 4: Comparative Carbon Reduction

Figure 4 shows that creating a municipal utility could allow the City to dramatically reduce its carbon emissions.

Figure 5 illustrates how, in 2020, the City would have less renewable energy if it pursued Scenario #2 and added 100 MW of wind firmed by natural gas, instead of being served by the wholesale market or remaining a retail customer of the incumbent IOU—despite having reduced its carbon emissions significantly. The observation may be counterintuitive, but the state's Renewable Energy Standard (RES) reflects the proportion of renewable energy in the fuel mix, not necessarily carbon reduction. A MWh of coal produces 2,168 lb of CO_2 whereas a MWh of natural gas produces 903 lb. The 2020 projected state system mix would have 37 percent renewable energy and 18 percent natural gas, but still 45 percent of coal; the carbon content is anticipated to be 1,137 lb of CO_2 per MWh. In comparison, under Scenario #2, the wind has a capacity factor of 30 percent and the other 70 percent is supplemented with gas generation. The City would have only 35 percent renewable energy but its reliance on coal would be reduced to 20 percent; gas generation would change from 18 to 44 percent; and the City's carbon emissions would be approximately 840 lb of CO_2 per MWh. This data showcases the potential disagreement between carbon reduction and renewable portfolio.

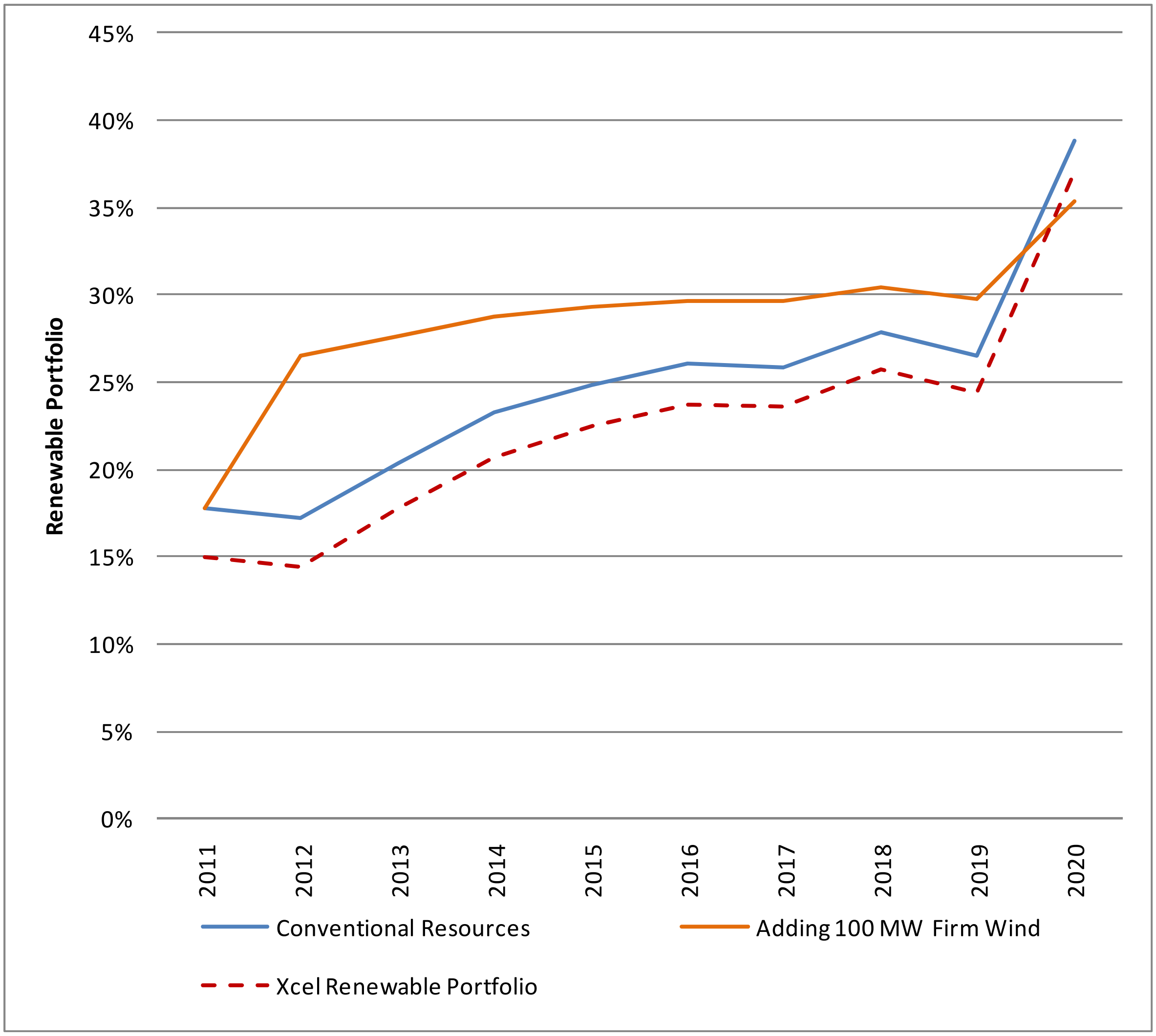


Figure 5: Renewable Portfolio Comparison

4.3 Reliability of Service

The three areas of reliability concern include transmission, resources, and distribution.

Transmission. As discussed above, the existing transmission grid will likely be unaffected by the creation of a municipal utility. Access to the WAPA and to the Tri-State transmission grids should only improve the utility's reliability through duplication of capacity. This access depends on the creation of a municipal utility.

Resources. The municipal utility is expected to have access to diverse resources. Independent power producers could contract with the City as their PPAs sunset with the incumbent IOU. Ideally, the development of renewable resources will shield the City somewhat from the long-term fluctuation of fossil fuel costs, without affecting the City's ability to procure dispatchable generation. Finally, the development of local resources could reduce the City's dependency on power supplied from outside the local distribution grid. Overall, the creation of a municipal utility could allow the City to develop a wide portfolio of resources and thus protect it from financial and physical risks.

Distribution. The reliability of the distribution system depends on maintenance, careful operation, undergrounding of lines, and management of local resources. Maintenance and operation were discussed under physical feasibility and should not present a concern for reliability. Much of the reliability can be enhanced with line undergrounding. The incumbent utility has undergrounded over 20 percent of the City's lines; because a municipal utility would not have to negotiate with a large third party to continue undergrounding, it may be able to achieve faster results.

This study concludes that reliability of service would be greatly enhanced by the creation of a municipal utility because it opens alternatives for transmission and resources, and options for technically advanced solutions otherwise not made available by the incumbent utility. One notable caveat, however, is that localization efforts—including battery storage, increased solar PV, and plug-in electric vehicles—may depend on proactive upgrades, depending on "how far, how fast" the City wants to move.

5 Financial Feasibility

The financial feasibility study is derived from energy and cost models that perform hourly energy calculations for the 10-year window of the study; cost calculations are derived monthly with on-peak and off-peak differentiation.

5.1 City Load

The incumbent IOU provided an hourly profile of the aggregated City load for calendar year 2010. That load is used as a base for all years of the study. Load details include:

- A 68 percent load factor[17]
- A seasonal base load of 116 MW
- A summer peak demand of 236 MW
- An annual energy consumption of 1,396,324 MWh in 2010

[17] The load factor is the ratio of average annual demand (159 MW) over peak annual demand (236 MW)

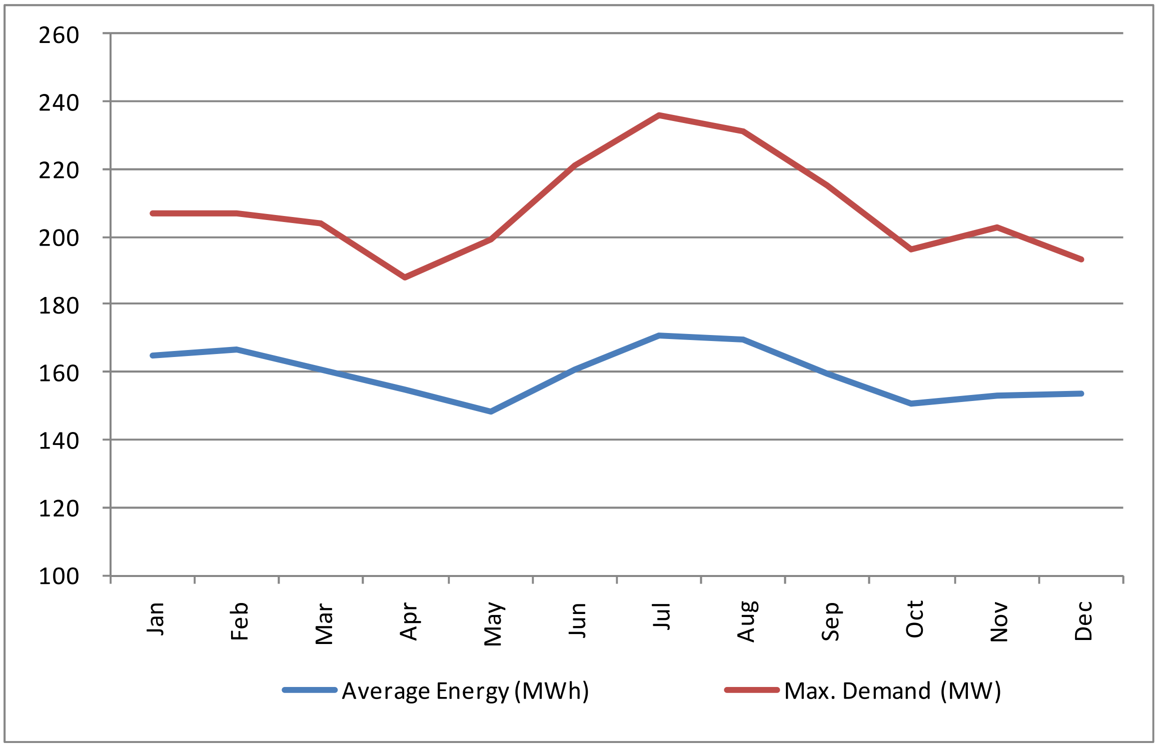


Figure 6: 2010 City Load

The City's 20-year historical energy growth averages 1.80 percent per year, while the model uses 1.50 percent. In addition, the 2010 load profile was not increased by 1.50 percent for 2011.

5.2 Stranded Cost Estimate: Not Applicable

Stranded costs compensate utilities for prudently incurred costs to serve retail or wholesale customers that become unrecoverable when a previously captive customer relies on FERC-mandated Open Access to choose an alternative generation supplier. In the past, stranded costs have been largely negotiated between the departing customer and the incumbent utility. FERC has created a formula it applies in case of litigation:

<u>SCO = (RSE - CMV) x LO</u>, where

- SCO is the Stranded Cost Obligation to be paid by the departing customer to the incumbent utility.
- RSE is the incumbent utility's Revenue Stream Estimate from serving the customer.
- CMV is the Competitive Market Value of the incumbent utility's stranded assets.
- LO is the length of obligation in years.

At this juncture, the study assumes that Xcel's stranded cost estimate is too speculative to include in the model.

5.3 Acquisition Costs: $121 million

The City may acquire the distribution system from the incumbent utility for its municipal utility operation. Xcel took control and custody of the City's distribution system on behalf of Public Service Company of Colorado (PSCo) in 1996. An inventory and valuation study of the distribution assets was recently performed.[18] This study was based on asset information between 1948 and 2005, and on Xcel's then-budgeted expenses for 2006 to 2010. Table 1 summarizes the estimated values for the distribution assets by FERC account number. A complete survey and valuation of the distribution assets will be necessary to settle the acquisition cost.

FERC Account No.	Description	Original Cost	Cumulative Depreciation	Book Value	Replacement Value New	Replacement Cost New Less Depreciation
302	Intg Frachises & Consents	$234,045	$184,166	$49,879	$1,973,573	$1,789,407
356	Tran OH Conductor & Device	$34,236	$9,410	$24,826	$54,582	$45,172
360.1	Dist Land Owned in Fee	$222,371	$0	$222,371	$658,197	$658,197
360.2	Distribution Land Rights	$98	$45	$53	$428	$382
361	Distribution Str & Improve	$13,247,153	$1,523,794	$11,723,359	$20,635,976	$19,112,182
362	Distribution Station Equip	$8,130,317	$3,534,503	$4,595,814	$25,823,526	$22,289,023
389.1	General Land Owned in Fee	$49,552	$4,093	$45,459	$69,173	$65,080
390	Genl Structures & Improve	$1,864,564	$536,276	$1,328,287	$3,482,372	$2,946,095
390.6	Genl Str & Imp-Owned Bldg	$1,175,118	$638,756	$536,362	$3,730,979	$3,092,223
391	General Office Furn & Eqp	$2,667	$493	$2,174	$4,609	$4,116
394	General Tools & Shop Equip	$6,061	$1,300	$4,761	$10,594	$9,294
397	General Communication Eqp	$641,990	$254,914	$387,076	$1,412,445	$1,157,531
398	General Miscellaneous Eqp	$3,335	$915	$2,420	$6,175	$5,260
369	Services-Overhead	$13,282,000	$862,208	$12,419,792	$15,357,411	$14,495,204
369.1	UG Services	$48,000,000	$3,732,294	$44,267,706	$48,285,600	$44,553,306
373	Street Lighting-Overhead	$226,000	$11,887	$214,113	$535,054	$523,167
373.2	Street Lighting-Underground	$8,465,000	$552,996	$7,912,004	$11,058,232	$10,505,236
Total		**$95,584,505**	**$11,848,050**	**$83,736,455**	**$133,098,925**	**$121,250,875**

Table 1: Summary of Distribution Asset Valuation[19]

[18] See 2011 Boulder Asset Inventory Report – Robertson-Bryan, Inc.

[19] FERC Account 369 includes poles, towers and pole-mounted transformers (FERC Accounts 364 and 368). FERC Account 369.1 includes UG Conduit and pad-mounted transformers (FERC accounts 366 and 368.1).

The Replacement Value New, or Replacement Cost New (RCN), is the cost to replace the distribution system today; this cost is estimated by projecting forward the cost of each asset with Handy-Whitman coefficients.[20] The Replacement Cost New Less Depreciation (RCNLD) has been the starting point in negotiations of acquisitions costs with incumbent utilities. This method of valuation reviews the entire electric utility system to be taken over, and replaces the entire system with new equipment, as if it were to be built new again with the knowledge of how the utility system currently operates, and then deducts from the determined replacement cost the depreciation for each particular system asset.

The RCN estimate based on the distribution asset valuation compares favorably with PSCo's 2009 annual report, which estimated the allocation of plant investment to serve customers in the City of Boulder. Under the Local System cost items, PSCo's estimate for distribution lines and facilities is $129,111,000, Common Property amounts to $3,387,567 for a total of $132,498,567 in the 2009 report. Hence the estimated 2010 RCN of $133 million is within 0.5 percent of PSCo's 2009 valuation.

		2009
Local System		
Distribution lines and facilities	$	129,111,000
General property		0
Common property:		
Franchises		434,200
Land and land rights		25,642
Structures and improvements		1,658,528
Office furniture and fixtures		43,000
Transportation equipment		1,048,922
Stores equipment		0
Tools, shop and garage equipment		0
Power operated equipment		175,549
Communication equipment		0
Miscellaneous equipment		1,726
Total common property		3,387,567
TOTAL:	**$**	**132,498,567**

Table 2: PSCo's 2009 Estimate of Distribution Assets cost allocation to Boulder

There are caveats in comparing Xcel's annual report and the City's recent asset inventory. First, Xcel's allocation of distribution costs is not based on the actual assets but rather on Boulder's share of the entire PSCo's assets in proportion to the City's energy. Second, PSCo's estimate of land and land rights (FERC accounts 360.1, 360.2 and 389.2) is significantly lower than the independent estimate.[21]

[20] For additional information, see Attachment E: Asset Valuation.
[21] Xcel's service yard on 63rd Street is located outside the City limits.

Lastly, PSCo's inclusion of a franchise cost is questionable since franchise fees are passed through to the ratepayers.

The asset inventory and valuation does not include the meters for the following reasons:

- Three-phase meters, typically used at transmission and primary distribution voltage levels, represent a replacement cost new of $150,000 to $200,000, considerably less if the meters are older.
- Billing meters are typically watt-hour meters, which the municipal utility would likely upgrade to advanced interval meters.
- Smart meters are probably accounted for in the valuation of SmartGridCity™. Including these meters in the current asset valuation would result in double-counting.

Pending a detailed inventory, the municipal utility would probably replace all the meters to support its localization strategy rather than acquire legacy meters from the incumbent utility. Nonetheless, the current meter valuation is between $5 and $7 million; the distribution asset valuation accounts for this amount as it includes the IOU's service yard located outside of the City limits (FERC accounts 390 and above) for an RCNLD of $7.2 million.

The feasibility study assumes the RCNLD of $121 million for acquisition cost of the distribution system.

5.3.1 SmartGridCity™: N/A

This study does not consider the acquisition of the SmartGridCity™ infrastructure as a necessity for the municipal utility.

5.4 Start-up Costs: $60.5 million

Projected start-up costs entail:

- Severance of the distribution system
- Logistics
- Legal and engineering services
- Spare equipment purchases

The estimated start-up costs represent 27 percent of the utility financing. However, these projected costs remain uncertain because they represent a small portion of the initial bond financing and can bear a high error percentage without affecting the feasibility substantially.

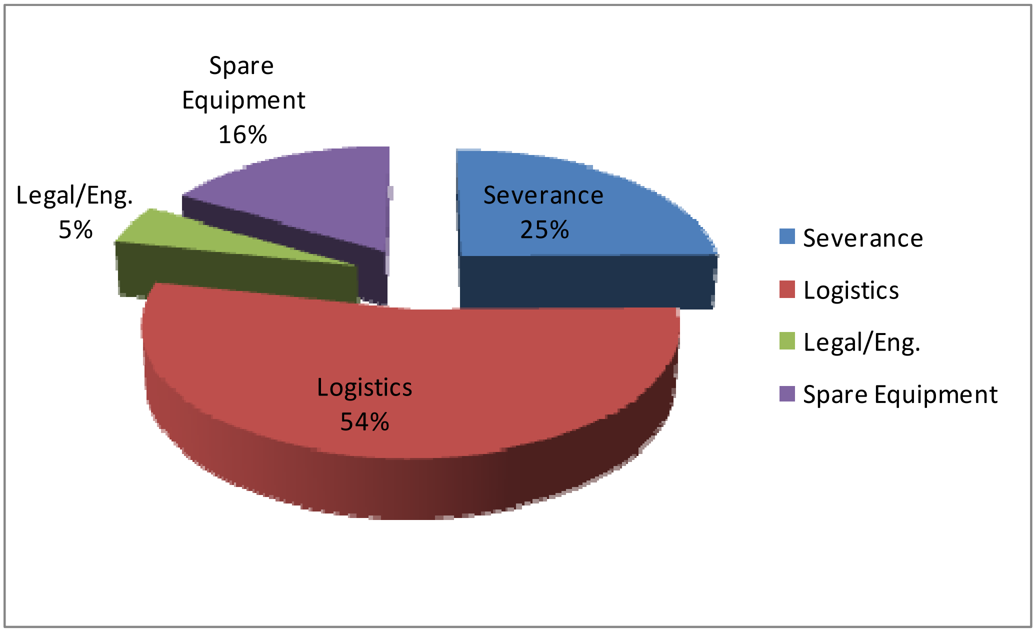


Figure 7: Distribution of Start-up Costs

5.4.1 Distribution System Severance: $15 million

The description and cost of severance was detailed in the RW Beck 2005 study[22] and subsequent 2007 update. The severance cost was estimated at $7.7 million by RW Beck (in 2006 dollars). This cost was updated to $15 million in 2011 dollars for this feasibility study. Since the incumbent utility has not provided detailed feeder line layouts to date, a detailed study of the severance would be unreasonably time consuming at this stage. Furthermore, pending legal feasibility, much if not all the severance cost may be avoidable if customers located outside the City limits opt to be served by the municipal utility or if the City annexes these areas served by its substations.

The severance cost entails separating the distribution circuits at several substations to distinguish the City's customers from the incumbent's. The substations that will need severance work include:

- Leggett on 63rd Street, which feeds customers located outside of the City limit around Baseline Reservoir and north of the Valmont reservoir.
- Gunbarrel on 75th Street, which feeds customers located around the City enclave.
- Sunshine Canyon on the west end of Mapleton Avenue, which feeds customers in the foothills.

If the City chooses to create a municipal utility, a complete severance study should be undertaken.

[22] See RW Beck Preliminary Municipalization Feasibility Study, October 2005

5.4.2 Legal and Engineering Costs: $3 million

The City would incur legal and engineering costs to establish the municipal utility. These services would include the FERC application, OATT wholesale account applications, bonding, utility charter, asset survey, and utility operations set-up for metering, billing and scheduling. RW Beck estimated the legal and engineering services at $2 million and this number was increased to $3 million in this feasibility study. The cost of litigation is not included in this study since it is difficult to evaluate and is speculative.

5.4.3 Spare Equipment: $10 million

Spare equipment allows the utility to perform maintenance upgrades and repair promptly a catastrophic failure without having to wait for long lead-time items. Spare equipment was estimated at $5.4 million by RW Beck. This budget was updated to $10 million in this study, which is 7.5 percent of the estimated replacement cost new of the distribution system.

The spare equipment cost would be refined during creation of the municipal utility, as part of the engineering study. This cost may be mitigated by creating alliances with other neighbor utilities, equipment vendors and possibly Xcel.

5.4.4 Logistics: $32.5 million

Logistics include the staffing effort and purchase of office, vehicles, tools, equipment, etc to operate the municipal utility. A thorough study was conducted by the City of Boulder in 2007.[23] The budget outlined in the City's 2007 study was used by RW Beck in their 2008 report update, totaling $27.9 million. The budget was increased to $32.5 million in this study.

The logistics budget would need to be refined during creation of the municipal utility as several services may be outsourced. However, the City could benefit from utilizing its water and wastewater utilities staff and infrastructure, and from the cooperation of other municipal utilities.

5.5 Operating Cash Reserve: $41.3 million

The municipal utility would need to carry a cash reserve to qualify for creditworthiness with wholesale counterparties such as Xcel[24] and market suppliers,[25] and to be prepared for unforeseen events. The cash reserve consists of:

- 2nd year operation and maintenance budget reserve for 1 year: $ 11.8 million
- 2nd year wholesale energy and transmission costs for 5 months: $ 29.5 million

[23] See Electric Municipalization Project – Administrative and Operational Issues Report. February 14, 2007
[24] See Xcel OATT credit requirements
[25] Wholesale market suppliers require creditworthiness to enter into power purchase agreements. See Marin CCA and Shell Energy North America.

The energy and transmission reserve exceeds the industry requirements. On the one hand, a new municipal utility would need to build credibility with counterparties, and financial reserves provide risk protection where history is lacking. On the other hand, the feasibility study lumps the operating reserve with other debt financed by taxable bond; in reality, the municipal utility would probably not need to carry the 8 percent finance cost over 30 years for the operating reserve.

In summary, the higher operating cash reserve is probably prudent, but it could impact rates and comparative savings when compared against those of Xcel. Furthermore, rate derivation does not include interest revenue from the reserve. The City could also consider reducing the reserve after 2 to 3 years of proven operation.

5.6 Bond Financing

The initial cost to form the municipal utility is estimated at $223 million. It entails:

- Transfer of Ownership: $ 121 million
- Start-up Costs: $ 60.5 million
- Cash Reserve: $ 41.3 million

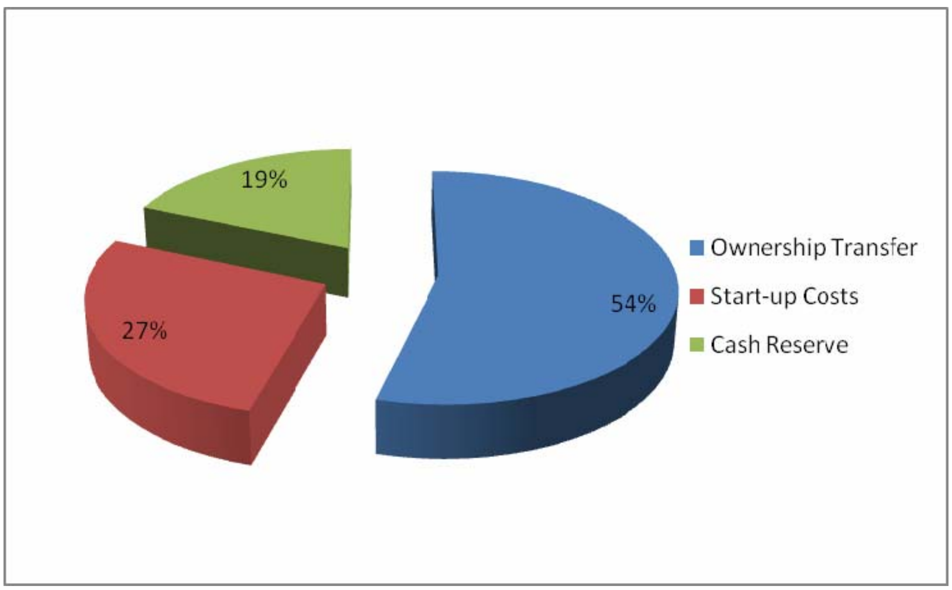


Figure 8: Bond Financing Composition

The City may finance $177.5 million of the above costs with a taxable bond:

- Acquisition Cost
- Operating Cash Reserve
- Severance

The remaining $45.5 million could be financed by a non-taxable bond:

- Start-up logistics
- Start-up legal and engineering
- Spare equipment

The feasibility study modeled two bonds with the following parameters:

BOND:		TAXABLE		NON-TAXABLE
Project Fund ($000's):	$	177,535	$	45,500
Term (years)		30		30
Payments/year:		2		2
Coupon Rate:		8.00%		5.76%
Debt Service Reserve:		10%		10%
Capitalized Interest (Years):		1.5		1.5
Interest Income:		1.50%		1.50%
Start Year:		2011		2011
Underwriting Cost ($000's):	$	2,306	$	566
Capitalized Interest Fund ($000's):	$	27,668	$	4,892
Debt Service Reserve Fund ($000's):	$	23,056	$	5,662
Bond Par Amount ($000's):	**$**	**230,565**	**$**	**56,620**

Table 3: Bond Parameters

The taxable bond coupon rate is set at 8 percent. The bonds will be offered on a competitive sale basis, as required by City Charter, which may preclude mini-bonds and popular participation.

The study uses a 30-year term to minimize the impact of bond financing on the rates and comparative savings. The bond modeling entails two coupon payments per year and a single annual retirement payment starting on the third year. Interest revenue at 1.50 percent annual rate is re-injected into utility operations to offset other costs but is not included in rate calculations. The interest is compounded every 6 months.

The feasibility study is based on the following bond assumptions:

- 18 months of capitalized interests
- 10 percent debt service reserve
- No ties to the City's existing utility bond ratings

Under the model assumptions, the average debt service coverage ratio is 1.72.

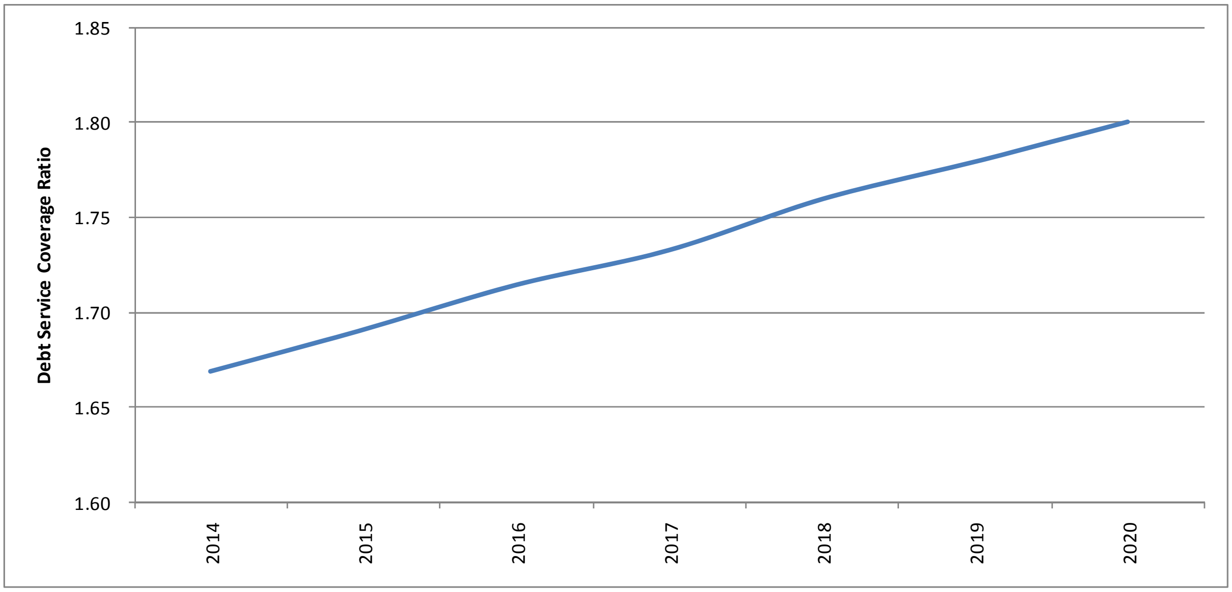


Figure 9: Debt Service Coverage Ratio

5.7 Utility Operations Annual Budget: $13 million

The utility operations budget entails the following cost components:

- Staffing
- Supplies
- Distribution system expansion
- Outside services and dues

The incumbent utility allocates $12.5 million to the City in its 2009 budget for these services, based on total cost allocation proportional to the City's annual energy. However, the IOU has to serve a more challenging territory and faces issues like terrain, distance, areas of low population and areas of rapid growth. In comparison, the municipal utility operation could have lower expenses because the territory is confined to the City limits.

5.7.1 Staffing: $8.9 million per year

Staffing represents 68 percent of the total operating budget. The preliminary head count totals 97 employees, relying on the 2007 City study.[26]

The following table summarizes the projected municipal utility staffing by activity:

Cost Category		Count
General Administration:	1	14
Billing	2	16
Metering	3	8
Scheduling	4	8
Distribution	5	51
Total		*97*

Table 4: Staffing by Activity

Other municipal utilities share positions across the municipal organization. Further analysis would be needed to assess overall staffing needs and the feasibility of sharing positions at the City.

5.7.2 Supplies: $670,000 per year

Supplies include:

	Annual budget ($000's)
Vehicle fuel	$ 50
Scheduling software license	$ 50
Meter maintenance supplies	$ 250
SCADA spares and upgrades	$ 120
Metering software licenses	$ 50
Billing software license	$ 50
Office supplies	$ 100
Total:	**$ 670**

Table 5: Supplies Annual Budget

[26] See Electric Municipalization Project – Administrative and Operational Issues Report. February 14, 2007

5.7.3 Distribution System Expansion: $1.5 million per year

The distribution system expansion budget entails:

- Line under-grounding: $900,000 per year
- System expansion: $600,000 per year

This budget is based on upgrades the City could make to the distribution system.

5.7.4 Outside Services and Dues: $1.95 million annually

Outside services and dues include:

	Annual budget ($000's)
Board and meetings	$ 100
Legal services	$ 600
Insurance (1 percent of operating cost)	$ 1,000
Audits	$ 50
Dues and NERC	$ 100
Distribution operation insurance (linemen)	$ 100
	$ 1,950

Table 6: Outside Services Budget

5.7.5 Utility Operation by Activity

In addition to updating the RW Beck figures, another approach to budgeting utility operation is by sector of activity. Using this approach, the 2011 annual budget (on a cash basis) would be:

- General Administration: $ 3.2 million
- Billing: $ 1.6 million
- Metering: $ 0.9 million
- Scheduling: $ 0.7 million
- Upgrades and undergrounding: $1.5 million
- Distribution: $ 5 million

Total: $ 13 million

The operating budget was derived for 2011 and increased by 2.5 percent each year to account for inflation. Operations represent an average 11 percent of the utility's total annual cost.

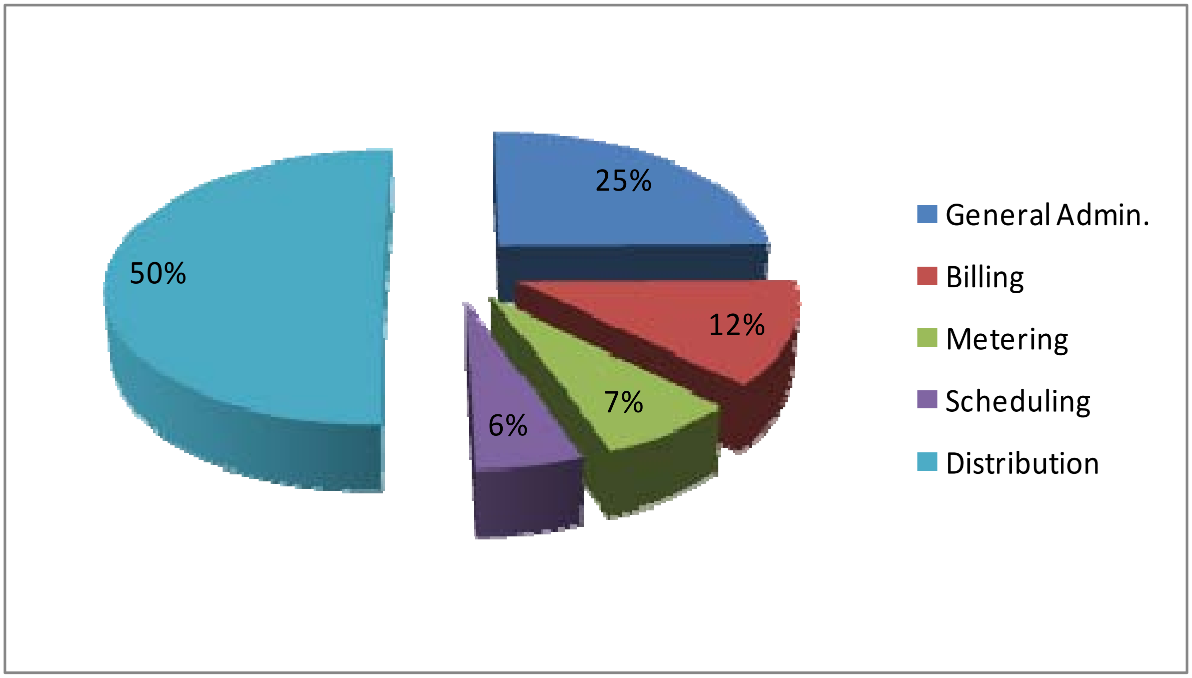


Figure 10: Utility Operation Cost Distribution

5.8 Energy Resources

Energy Resources in this feasibility study include local renewable generation, supplemental wholesale resources, transmission and ancillary services.

5.8.1 Local Renewable Generation

The feasibility study focuses on the existing infrastructure. Current local resources include the City-owned hydroelectric power, but not Solar*Rewards PV projects. Further efforts in localization of generation, energy storage and demand-side management are deemed outside of this feasibility study because their implementation would likely follow, not lead, the creation of the municipal utility.

The model assumes a purchase rate for City-owned hydroelectricity of $45.60 per MWh (4.56 cents per kWh), subject to a 2.50 percent annual increase. The development of additional renewable resources, including local solar PV, is addressed in the Business Plan.

5.8.2 Wholesale Supplemental Market

The wholesale market resource consists of futures and day-ahead transactions. The wholesale resource may be purchased from a variety of market suppliers, including the incumbent utility. The trades are typically indexed to the InterContinental Exchange (ICE) or the Dow Jones Index (DJI). The market resource rate forecast was priced at the price point "WECC East Colorado" and based on market-clearing price forecasts.[27]

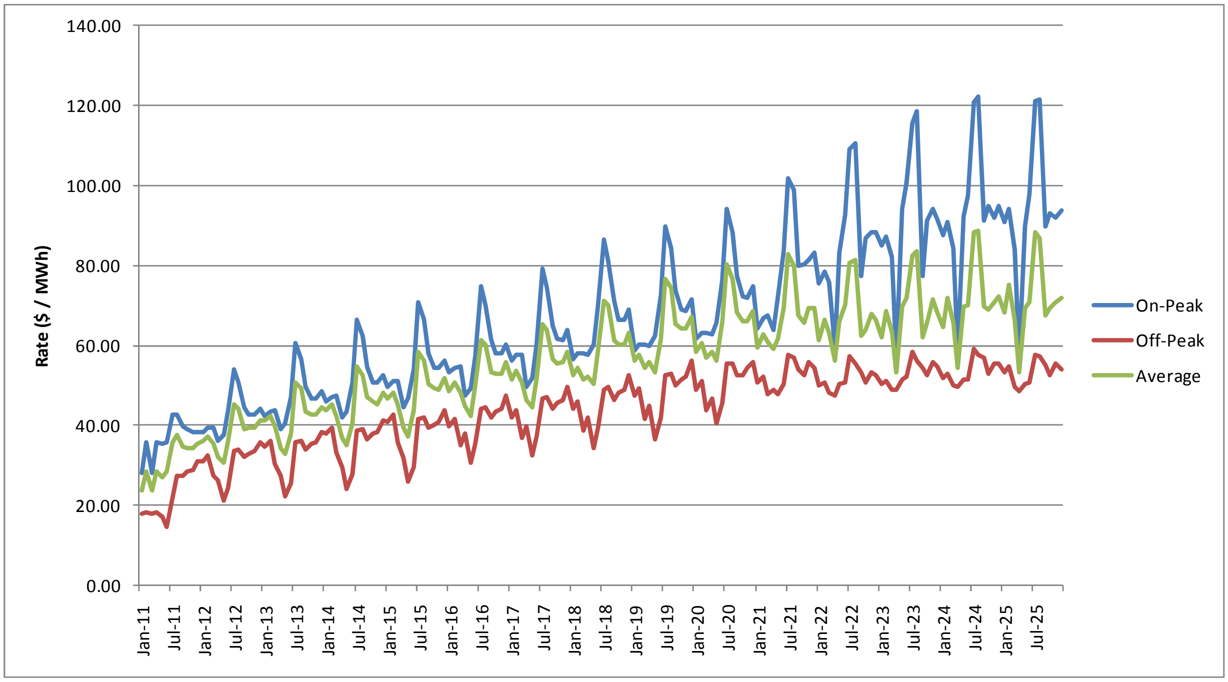


Figure 11: Market Rate Forecast

The model applies on-peak or off-peak rates to each hourly energy trade, as the wholesale market supplements the other resources to balance the load. The rate forecast will become increasingly speculative beyond the first four years.

Energy pricing in a non-ISO[28] market would require further analysis. On the one hand, Xcel has filed its energy resource price forecast under the Clean Air–Clean Jobs Act; this represents the high side of wholesale pricing. On the other hand, market-clearing price forecasts in East Colorado provide the low end.[29] Market forecasts are used with counterparties to negotiate futures contracts. The feasibility study uses market prices between the two book-ends above by applying a significant margin to the market forecast.

[27] See Ventyx for fundamentals.
[28] ISO: Independent System Operator. In an ISO market, the Balancing Area is controlled by an organization independent of the IOUs.
[29] Ventyx 2011 Power Reference Case, updated 5/12/11. Prices changed to nominal dollars.

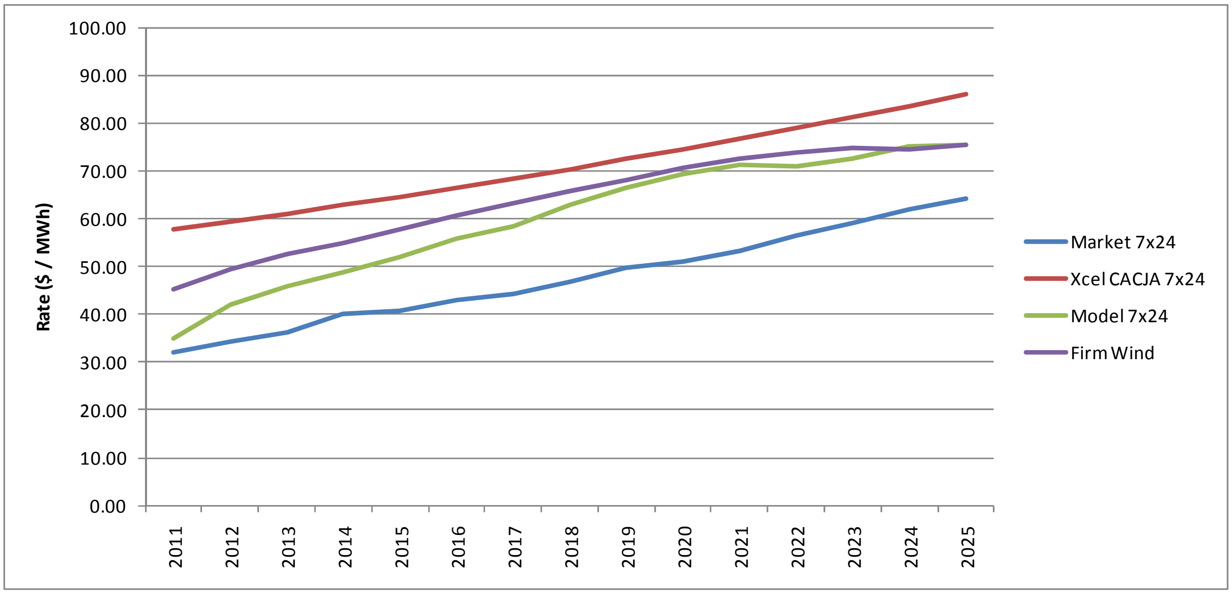


Figure 12: Market Price Comparison

Based on heat rates, the feasibility study projects a lower cost for wholesale market energy than the IOU's estimated cost of sales for resale.[30] When bringing in the natural gas pricing forecast,[31] it appears that the IOU's heat rate is at or above 12,000 BTU per kWh until 2016, which is surprising in a coal-dominated market with significant wind resource priced as low as $55.00 per MWh. The above graph shows that the IOU market pricing is still higher than firm wind resources.[32] In other words, the municipal utility could deploy natural gas generation with a heat rate below 9,000 BTU / kWh to firm wind with only 30 percent capacity factor, and generate a resource priced competitively against the IOU's wholesale market energy. In addition, the municipal utility could claim the natural gas generation as capacity reserve and offset some ancillary service costs.

[30] XCEL CACJA energy rate derivation: See Nexant et al. 2011 Baseline Analysis. The heat rate is a measure of how many BTUs of fuel it takes to produce 1 kWh. It compares to how many gallons of gas a car consumes over 1,000 miles. A high heat rate is indicative of low efficiency or high O&M costs. The market heat rate in Figure 13 is derived from Ventyx's natural gas price at burner tip for the Colorado and Rocky Mountain region, updated on May 12, 2011 and changed to nominal dollars. For good measure, Figure 13 also includes the model's on-peak heat rate.

[31] Natural gas price forecast at El Paso – San Juan plus delivery margin of $0.60 per MM BTU. See also Ventyx fundamentals price forecast at burner tip, East Colorado.

[32] Assumes 30 percent wind capacity factor and 9,000 heat rate natural gas generator. Excludes capacity charges.

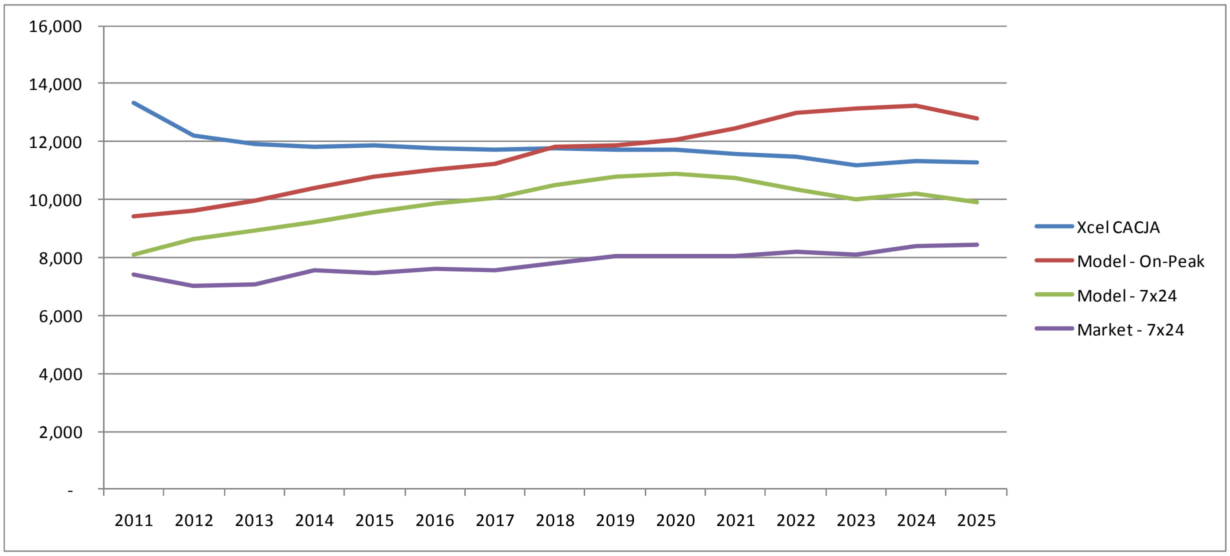


Figure 13: Comparative Heat Rates

In addition to the heat rate analysis above, Figure 14 below shows how the model on-peak price forecast compares conservatively to ICE's publication of Cleared Forwards and Day-Ahead prices at Palo Verde and Four Corners on-peak pricing indices. The municipal utility would also have access to the Western System Power Pool (WSPP) as another alternative to the incumbent's wholesale market.

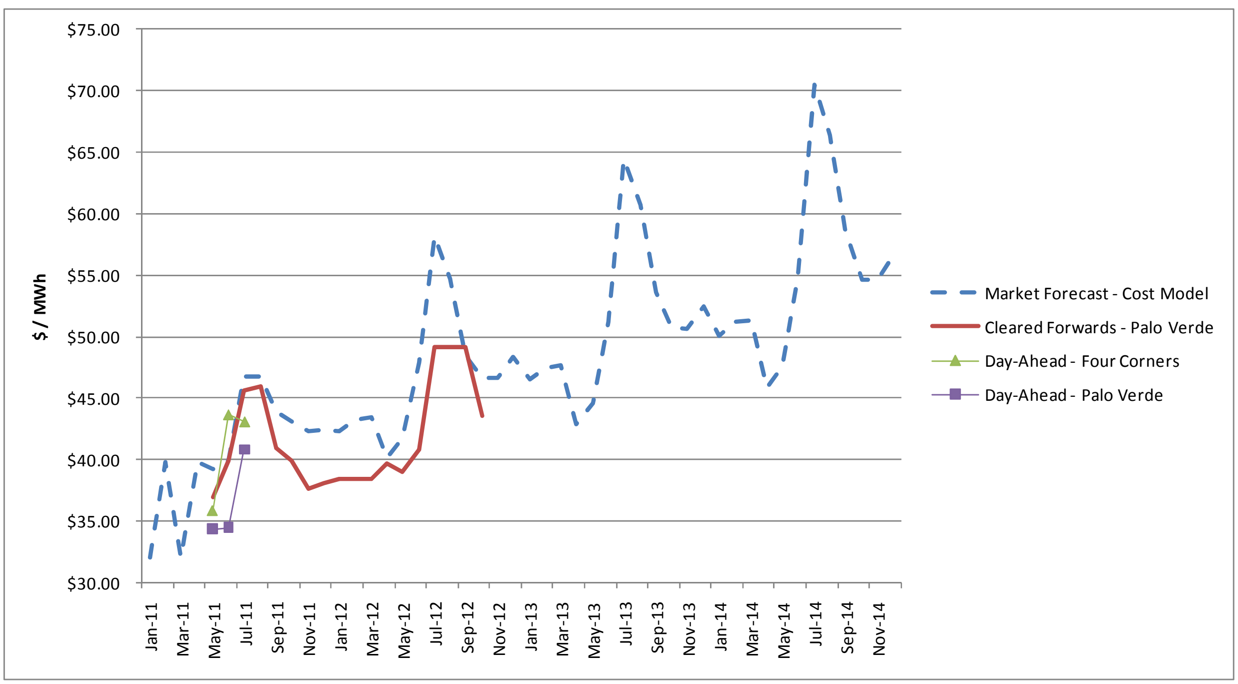


Figure 14: Model Versus Actual Market Price - Updated 7/15/11

In summary, the incumbent utility's price forecast seems high and a municipal utility may have other options. However, the municipal utility would be subject to the IOU's energy pricing for imbalance settlements.

5.8.3 Wholesale Transmission

Wholesale transmission and ancillary services are regulated under the Open Access Transmission Tariff (OATT).[33] Unlike energy charges, wholesale transmission is priced according to the peak monthly load in kW. The model uses only Network Integration (NITS) rates because Point-to-Point (P2P) schedules are resource-specific. In other words, the municipal utility and its main resources would likely be network-integrated; P2P service may be required for certain generators, but this issue would arise with time on a resource-specific basis.

Network Integration Delivery (Part III)		/kW-Month of network Load		
Schedule	Description	Effective	Network Load	2011
1	Scheduling, SC and Dispatch	7/30/2010	100.00%	$ 0.0700
2	Reactive Supply and Voltage Control	7/30/2010	100.00%	$ 0.0775
3	Regulation and Frequency Response	7/30/2010	1.50%	$ 6.7400
5	Operating Reserve - Spinning Reserve	7/30/2010	3.50%	$ 6.8750
6	Operating Reserve - Supplemental Reserve	7/30/2010	3.50%	$ 3.7150
13	Network Integration	7/30/2010	100.00%	$ 1.9810

Table 7: OATT Tariff

In the model, the OATT tariff is increased by 2.50 percent annually to account for inflation. The model assumes perfect hourly schedules for simplicity. Budgeting for load imbalance would be completely speculative as it results in charges or credits each month.

Transmission amounts to $6.8 million annually[34] (in 2011 dollars) under the load profile used in the model and represents approximately 7.5 percent of the total municipal utility revenue requirement.

5.9 Revenue Requirement and Income

The municipal utility incurs costs to serve the City's load. The costs entail:

- Resources and wholesale transmission
- Utility operations
- Debt Service
- Payment in Lieu of Taxes (PILOT)

[33] For more detailed information, see Attachment D: OATT Report.
[34] City-owned hydropower is delivered on the transmission side of the Main distribution substation, therefore it does not offset any of the load's transmission cost.

- Public Purpose Program Fund (P^3 Fund)
- Asset depreciation
- Minimum Revenue Requirement

Together, these costs constitute the municipal utility's revenue requirement. The utility income could exceed the revenue requirement if the composite rates were set higher than those derived by the revenue requirement.

Because the creation of a municipal utility would preclude the City's collection of an occupation tax, the payment in lieu of taxes (PILOT) allows the City to maintain a revenue stream for its general fund. PILOT funds would comprise 4 percent of the cost of resources, transmission and utility operations. The estimated 10 year average revenue from PILOT is approximately $4.3 million annually.

The P^3 Fund would comprise 5 percent of the cost of resources, transmission and utility operations. The intent is to generate a fund for the implementation of energy efficiency and conservation programs. The P^3 fund collects about $5.3 million annually on a 10 year average.

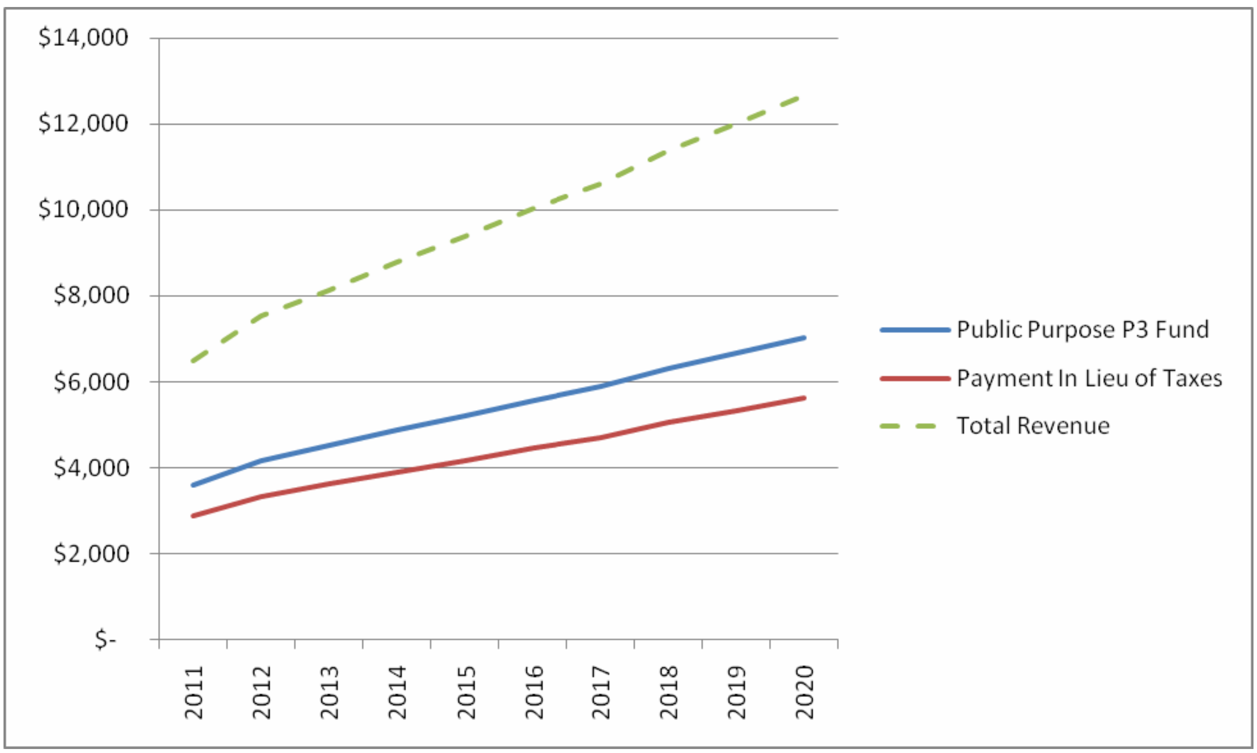


Figure 15: PILOT and P^3 Fund Revenues

Both the PILOT and P^3 Fund would provide significant revenues to the City to replace the Climate Action Program Tax and Occupation Tax, both of which are due to sunset by 2013 and 2015, respectively.

5.9.1 Utility Income

The following graph shows the composition of the operating cost on a cash basis, together with the revenue requirement on an income basis.[35]

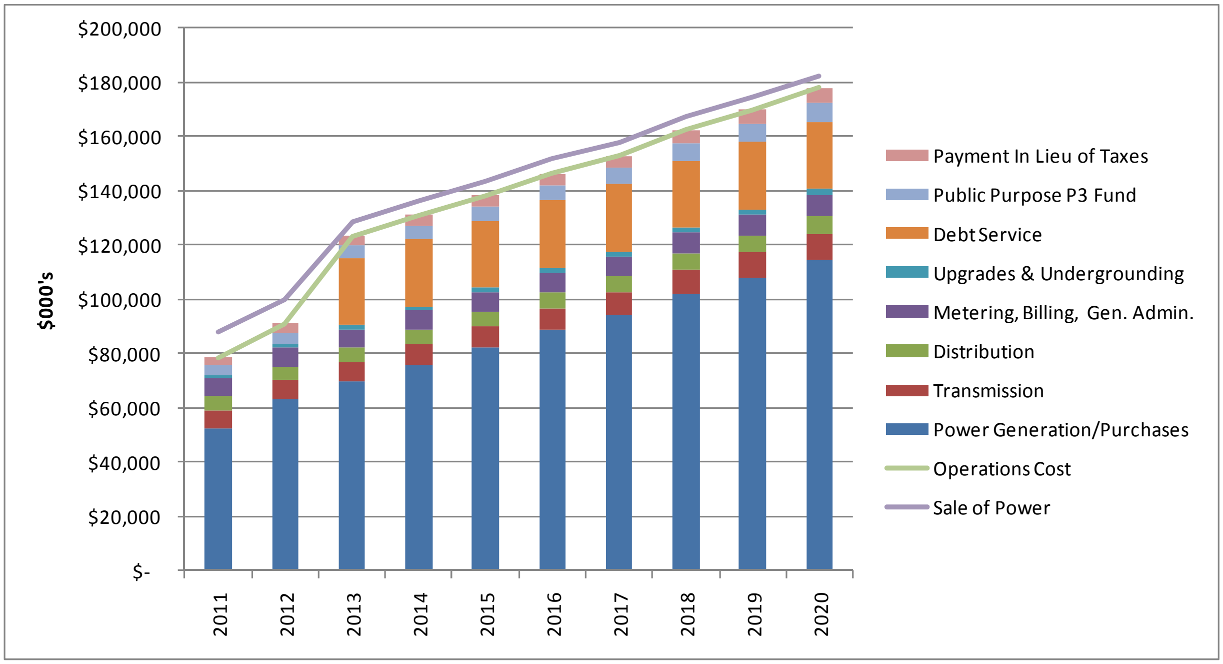


Figure 16: Utility Revenue Requirement Components

The graph above shows a positive cash flow between the revenue requirement (sale of power), computed on an income basis, and the operations costs computed on a cash basis. The cash flow is maintained around $5 million annually.

6 Customer Rates

Rates are used for revenue collection under a cost and energy budget. This section shows how the municipal utility's potential rates can be derived by customer class for residential, low income, commercial and industrial customers. There are many factors that can be varied in the rate derivation; this study shows an example of the rates, but any strategic discussion would need to be addressed by the Board.

[35] Acknowledgement to the Financial Engineering Company – M. Hubbard, P.E.

6.1 Basic Assumptions

The rates analysis model uses operations costs calculated in the cost model, divided by energy load ($/MWH), and compares the results to the incumbent utility's projected composite rates. Additionally, the rate calculations file is used to divide the City's total costs into customer segments. The construct of the customer segments is based on data from the Baseline Analysis.[36]

From the Baseline Analysis, the current electric utility customers consist of Residential, Commercial, Industrial, and Streetlight customers. Low Income Residential was added in this feasibility analysis as a portion of the Residential class. Table 8 segments the customers by class and load.

Customer Type	Number of Accounts	Percent of Total Boulder Load
Residential	37,297	18
Low Income Residential	1,936 (5 % of Residential)	1
Commercial	7,820	79
Industrial	2	1
Other / Streetlight	13	1

Table 8: Summary of Customer Segmentation

The rates analysis model utilizes the ratio of customers and energy in each segment to allocate the Revenue Requirements. For transparency, the rates used to collect the revenue are designed to be representative of the budget items that they intend to collect. A summary of invoice rate items, current collection method selection, and the operations costs collected under each are:

[36] See Nexant et al. 2011 Baseline Analysis.

Invoice Rate / Charge	Collection Method	Operations Budget Line Items
Customer Charge	Lump Sum Per Month	General Administration Billing & Paying Scheduling Meter Management Debt Service Interest Depreciation and Amortization
Distribution	Per kWh or Peak kW (depending on customer type)	Distribution costs (labor and equipment)
Transmission	Per kWh or Peak kW (depending on customer type)	Transmission Ancillary Services
Energy Tier 1	Per kWh up to maximum limit	Resources
Energy Tier 2	Per kWh, two rates based on time of use (on- and off-peak)	Resources
Taxes	Percent of Invoice Subtotal	PILOT P3 Funds

Table 9: Summary Invoice Charge Items

The customer charge is a lump sum set amount each month. Transmission and distribution costs are applied on an energy (kWh) basis to the residential, low income, and street light accounts, and on a demand (kW) basis to the commercial and industrial accounts. Energy rates are based on time-of-use (on and off peak), and are tiered. The Tier 1 rate allowance is 500 kWh for residential, 400 kWh for low income accounts, 3,000 kWh for commercial and industrial, and 100 kWh for street lights. Energy billing under Tier 1 has a constant rate for all hours. The rates are split into two seasons as is practice by Xcel. Summer consists of June 1 through September 30, and Winter is October 1 through May 31. The table below shows the inputs to the rate model; the complete rate derivation is shown in Table 11.

Rate Structure	Residential	Residential-LI	Commercial	Industrial	Other / Streetlight	Allocation of Costs
Rate Schedule:	1	2	3	4	5	
Number of Customers	37,297	1,963	7,820	2	13	47,095
Winter Tier 1 maximum kWh allowance:	500	400	3,000	3,000	100	343,208,000
Summer Tier 1 maximum kWh allowance:	500	400	3,000	3,000	100	171,604,000
Winter Tier 1 rate per kWh:	0.015	0.015	0.025	0.025	0.025	0.025
Winter Tier 2 off-peak rate per kWh:	0.025	0.025	0.025	0.025	0.030	0.025
Summer Tier 1 rate per kWh:	0.015	0.015	0.025	0.025	0.025	0.025
Summer Tier 2 off-peak rate per kWh:	0.025	0.025	0.025	0.025	0.030	0.025
Transmission Basis:	Energy	Energy	Demand	Demand	Energy	Energy
Distribution Basis:	Energy	Energy	Demand	Demand	Energy	Energy
Energy Share of Boulder Load	18.0%	1.0%	79.0%	1.0%	1.0%	100.0%

Table 10: 2011 Rate Derivation Assumptions

6.2 Example Rate Sheet

Based on the assumptions in Table 10 above, below is a sample rate sheet for 2011:

Summary of Boulder Customer Power Rates							2011
Description		Residential	- Low Income	Commercial	Industrial	Other / Streetlights	City of Boulder
	Rate Schedule:	1	2	3	4	5	
Winter Proforma Rates (Oct 1 - May 31)							
Customer Charge (per month)		$43.23	$22.59	$205.16	$8,282.64	$2,728.23	$70.35
Transmission							
	Demand (peak kW)	-	-	2.6780	7.9336	-	-
	Energy (per kWh)	0.00334	0.00463	-	-	0.01388	0.00
Distribution							
	Demand (peak kW)	-	-	4.2391	12.5582	-	-
	Energy (per kWh)	0.00529	0.00733	-	-	0.02198	0.00733
Energy							
	Tier 1 All Hours	0.01500	0.01500	0.02500	0.02500	0.02500	0.02500
	Tier 2 On-Peak	0.14135	0.04332	0.05399	0.06706	0.21584	0.05455
	Tier 2 Off-Peak	0.02500	0.02500	0.02500	0.02500	0.03000	0.02500
Taxes (on invoice Total)		9.0%	9.0%	9.0%	9.0%	9.0%	9.0%
Winter Rates Summary							
	Power Cost ($)	18,655,498	701,540	52,257,081	989,541	2,050,540	74,652,203
	Energy Use (kWh)	164,257,687	9,125,427	720,908,739	9,125,427	9,125,427	912,542,708
	Composite Unit Rate ($/kWh)	0.1136	0.0769	0.0725	0.1084	0.2247	0.0818
Summer Proforma Rates (June 1 - Sept 30)							
Customer Charge (per month)		$43.23	$22.59	$205.16	$8,282.64	$2,728.23	$70.35
Transmission							
	Demand (peak kW)	-	-	2.6802	7.9400	-	-
	Energy (per kWh)	0.0036	0.0049	-	-	0.0148	0.0049
Distribution							
	Demand (peak kW)	-	-	3.7485	11.1049	-	-
	Energy (per kWh)	0.0050	0.0069	-	-	0.0207	0.0069
Energy							
	Tier 1 All Hours	0.0150	0.0150	0.0150	0.0250	0.0250	0.0250
	Tier 2 On-Peak	0.1654	0.0516	0.0678	0.0767	0.2384	0.0653
	Tier 2 Off-Peak	0.0250	0.0250	0.0250	0.0250	0.0300	0.0250
Taxes (on invoice Total)		9.0%	9.0%	9.0%	9.0%	9.0%	7.9%
Summer Rates Summary							
	Power Cost ($)	10,075,685	373,816	28,958,947	549,168	1,148,202	40,792,815
	Energy Use (kWh)	87,080,590	4,837,811	382,187,036	4,837,811	4,837,811	483,781,058
	Composite Unit Rate ($/kWh)	0.1157	0.0773	0.0758	0.1135	0.2373	0.0843
Annual Costs and Rates							
	Power Cost ($)	28,731,182	1,075,357	81,216,028	1,538,709	3,198,742	115,445,018
	Energy Use (kWh)	251,338,278	13,963,238	1,103,095,775	13,963,238	13,963,238	1,396,323,766
	Composite Unit Rate ($/kWh)	0.1143	0.0770	0.0736	0.1102	0.2291	0.0827
Xcel Average Comparison Rates ($/kWh):		**0.121**		**0.084**	**0.111**	**0.262**	**0.089**

Table 11: 2011 Rate Summary by Customer Segment

The figure below summarizes the annual composite rates for 2011 by customer segment compared to Xcel's rates.

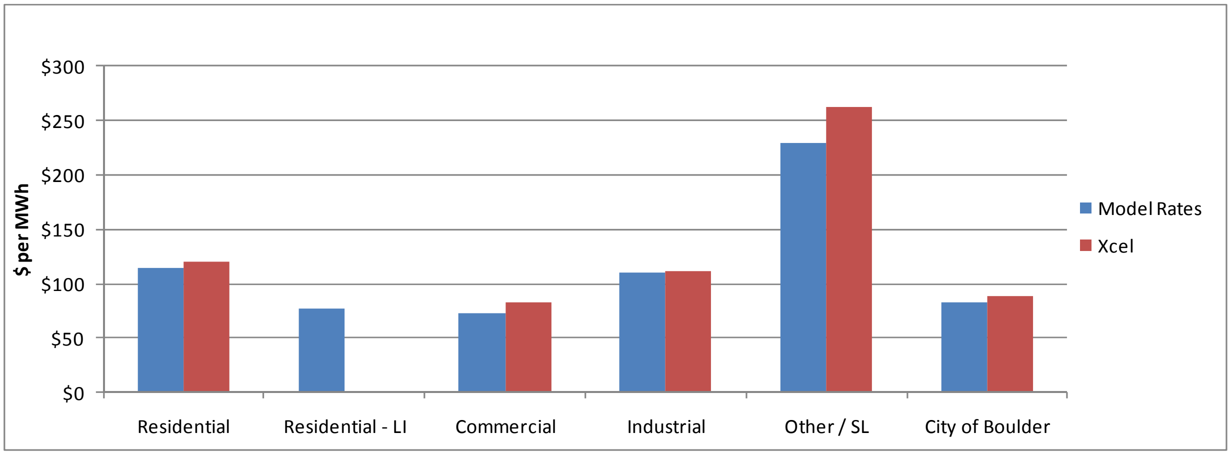


Figure 17: Annual Composite Rates by Customer Segment (based on 2011 Scenario #1)

6.3 Example Customer Invoice

Based on the rate sheet above in Table 11, below is a sample invoice for each customer segment of the proposed municipal utility. All information on this invoice is for demonstration purposes only and does not reflect real people, companies, or usage information.

Residential Customer Invoice:

Boulder Municipal Utility

City of Boulder Electric
PO Box 9999
Boulder, CO 99999
(303) 999-9999

Page 1 of 1

Customer Name	**Service Address**	**Account No.**	**Due Date**	**Amount Due**
Joe Smith	9999 Street St.	99-9999999-2	11/4/2011	**$ 79.22**
Jane Smith	BOULDER, CO 99999			

Account Activity			
Date of Bill	10/15/2011	Previous Balance	$ 50.00
Number of Payments Received	0	Total Payments	$ (50.00)
Number of Days in Billing Period	30	Balance Forward	$ -
Statement Number	40831	+ Current Bill	$ 79.22
Premise Number	9999999	**Current Balance**	**$ 79.22**

Electric Service - Account Summary

Invoice Number	408311		
Meter No.	28888		
Rate Schedule	1	Residential	
Days in Bill Period	30		
Current Reading	650000	Actual	8/1/2011
Previous Reading	649350	Actual	8/31/2011
Kilowatt-Hours Used	650		
Peak kW in the month	25		
Tier 1 kWh Allowance	500		

Residential Summer Rates

			kWh or kW	Rate	Cost
Customer Charge		per month			$ 43.23
Transmission					
	Demand	per kW	-	$ -	$ -
	Energy	per kWh	650	$ 0.00	$ 2.32
Distribution					
	Demand	per kW	-	$ -	$ -
	Energy	per kWh	650	$ 0.00	$ 3.24
Energy					
	Tier 1	per kWh	500	$ 0.02	$ 7.50
	Tier 2 On-Peak	per kWh	90	$ 0.17	$ 14.89
	Tier 2 Off-Peak	per kWh	60	$ 0.03	$ 1.50
Taxes			*Usage Subtotal:*		$ 72.68
	P3 Funds	per Usage Subtotal		4.0%	$ 2.91
	PILOT	per Usage Subtotal		5.0%	$ 3.63
			Total Service Charges:		**$ 79.22**

Figure 18: Residential Invoice Example

Low Income Residential Customer Invoice:

Boulder Municipal Utility

City of Boulder Electric
PO Box 9999
Boulder, CO 99999
(303) 999-9999

Page 1 of 1

Customer Name	Service Address	Account No.	Due Date	Amount Due
Joe Smith Sr.	9999 Street St. BOULDER, CO 99999	99-9999999-2	11/4/2011	$ **47.57**

Account Activity

Date of Bill	10/15/2011	Previous Balance	$	50.00
Number of Payments Received	0	Total Payments	$	(50.00)
Number of Days in Billing Period	30	Balance Forward	$	-
Statement Number	40831	+ Current Bill	$	47.57
Premise Number	9999999	**Current Balance**	**$**	**47.57**

Electric Service - Account Summary

Invoice Number	408311			Residentail - LI Summer Rates							
Meter No.	28888						kWh or kW		Rate		Cost
Rate Schedule	2	Residentail - LI		Customer Charge		per month				$	23.79
Days in Bill Period	30			Transmission							
Current Reading	600000	Actual	8/1/2011		Demand	per kW	-	$	-	$	-
Previous Reading	599400	Actual	8/31/2011		Energy	per kWh	600	$	0.00	$	2.96
Kilowatt-Hours Used	600			Distribution							
Peak kW in the month	10				Demand	per kW	-	$	-	$	-
Tier 1 kWh Allowance	400				Energy	per kWh	600	$	0.00	$	2.70
				Energy							
					Tier 1	per kWh	400	$	0.02	$	6.00
					Tier 2 On-Peak	per kWh	120	$	0.05	$	6.19
					Tier 2 Off-Peak	per kWh	80	$	0.03	$	2.00
				Taxes			*Usage Subtotal:*			$	43.64
					P3 Funds	per Usage Subtotal			5.0%	$	2.18
					PILOT	per Usage Subtotal			4.0%	$	1.75
							Total Service Charges:			**$**	**47.57**

Figure 19: Low Income Residential Invoice Example

Commercial Customer Invoice:

Boulder Municipal Utility

City of Boulder Electric
PO Box 9999
Boulder, CO 99999
(303) 999-9999

Page 1 of 1

Customer Name	Service Address	Account No.	Due Date	Amount Due
Store	9999 Street St. BOULDER, CO 99999	99-9999999-2	11/4/2011	**$ 5,887.18**

Account Activity			
Date of Bill	10/15/2011	Previous Balance	$ 50.00
Number of Payments Received	0	Total Payments	$ (50.00)
Number of Days in Billing Period	30	Balance Forward	$ -
Statement Number	40831	+ Current Bill	$ 5,887.18
Premise Number	9999999	**Current Balance**	**$ 5,887.18**

Electric Service - Account Summary

Invoice Number	408311		
Meter No.	28888		
Rate Schedule	3	Commercial	
Days in Bill Period	30		
Current Reading	30123000	Actual	8/1/2011
Previous Reading	30092877	Actual	8/31/2011
Kilowatt-Hours Used	30,123		
Peak kW in the month	780		
Tier 1 kWh Allowance	3,000		

Commercial Summer Rates

			kWh or kW	Rate	Cost
Customer Charge		per month			$ 224.62
Transmission					
	Demand	per kW	780	$ 2.52	$ 1,966.40
	Energy	per kWh	-	$ -	$ -
Distribution					
	Demand	per kW	780	$ 2.30	$ 1,790.31
	Energy	per kWh	-	$ -	$ -
Energy					
	Tier 1	per kWh	3,000	$ 0.02	$ 45.00
	Tier 2 On-Peak	per kWh	16,274	$ 0.07	$ 1,103.52
	Tier 2 Off-Peak	per kWh	10,849	$ 0.03	$ 271.23
Taxes				*Usage Subtotal:*	$ 5,401.08
	P3 Funds	per Usage Subtotal		5.0%	$ 270.05
	PILOT	per Usage Subtotal		4.0%	$ 216.04
				Total Service Charges:	**$ 5,887.18**

Figure 20: Commercial Invoice Example

Industrial Customer Invoice:

Boulder Municipal Utility

City of Boulder Electric
PO Box 9999
Boulder, CO 99999
(303) 999-9999

Page 1 of 1

Customer Name	Service Address	Account No.	Due Date	Amount Due
Industry	9999 Street St. BOULDER, CO 99999	99-9999999-2	11/4/2011	**$ 126,772.08**

Account Activity			
Date of Bill	10/15/2011	Previous Balance	$ 50.00
Number of Payments Received	0	Total Payments	$ (50.00)
Number of Days in Billing Period	30	Balance Forward	$ -
Statement Number	40831	+ Current Bill	$ 126,772.08
Premise Number	9999999	**Current Balance**	**$ 126,772.08**

Electric Service - Account Summary

Invoice Number	408311			Industrial	Summer Rates				
Meter No.	28888						kWh or kW	Rate	Cost
Rate Schedule	4	Industrial			Customer Charge	per month			$ 9,071.91
Days in Bill Period	30				Transmission				
Current Reading	56560000	Actual	8/1/2011		Demand	per kW	7,300	$ 7.47	$ 54,520.40
Previous Reading	56503440	Actual	8/31/2011		Energy	per kWh	-	$ -	$ -
Kilowatt-Hours Used	56,560				Distribution				
Peak kW in the month	7,300				Demand	per kW	7,300	$ 6.80	$ 49,638.10
Tier 1 kWh Allowance	3,000				Energy	per kWh	-	$ -	$ -
					Energy				
					Tier 1	per kWh	3,000	$ 0.03	$ 75.00
					Tier 2 On-Peak	per kWh	32,136	$ 0.08	$ 2,463.65
					Tier 2 Off-Peak	per kWh	21,424	$ 0.03	$ 535.60
					Taxes			*Usage Subtotal:*	$ 116,304.66
					P3 Funds	per Usage Subtotal		5.0%	$ 5,815.23
					PILOT	per Usage Subtotal		4.0%	$ 4,652.19
								Total Service Charges:	**$ 126,772.08**

Figure 21: Industrial Invoice Example

Other / StreetLight Customer Invoice:

Boulder Municipal Utility

City of Boulder Electric
PO Box 9999
Boulder, CO 99999
(303) 999-9999

Page 1 of 1

Customer Name	**Service Address**	**Account No.**	**Due Date**	**Amount Due**
Streetlight	9999 Street St. BOULDER, CO 99999	99-9999999-2	11/4/2011	**$ 6,266.08**

Account Activity

Date of Bill	10/15/2011	Previous Balance	$ 50.00
Number of Payments Received	0	Total Payments	$ (50.00)
Number of Days in Billing Period	30	Balance Forward	$ -
Statement Number	40831	+ Current Bill	$ 6,266.08
Premise Number	9999999	**Current Balance**	**$ 6,266.08**

Electric Service - Account Summary

Invoice Number	408311		
Meter No.	28888		
Rate Schedule	5	Other/Streetlight	
Days in Bill Period	30		
Current Reading	14880000	Actual	8/1/2011
Previous Reading	14865120	Actual	8/31/2011
Kilowatt-Hours Used	14,880		
Peak kW in the month	30		
Tier 1 kWh Allowance	100		

Other/Streetlight Summer Rates

			kWh or kW	Rate	Cost
Customer Charge		per month			$ 3,033.10
Transmission					
	Demand	per kW	-	$ -	$ -
	Energy	per kWh	14,880	$ 0.01	$ 220.53
Distribution					
	Demand	per kW	-	$ -	$ -
	Energy	per kWh	14,880	$ 0.01	$ 200.78
Energy					
	Tier 1	per kWh	100	$ 0.03	$ 2.50
	Tier 2 On-Peak	per kWh	8,868	$ 0.24	$ 2,114.43
	Tier 2 Off-Peak	per kWh	5,912	$ 0.03	$ 177.36
Taxes				*Usage Subtotal:*	$ 5,748.70
	P3 Funds	per Usage Subtotal		5.0%	$ 287.43
	PILOT	per Usage Subtotal		4.0%	$ 229.95
				Total Service Charges:	**$ 6,266.08**

Figure 22: Other/Streetlight Invoice Example

6.4 Long-term Rates Summary

The following figures graphically summarize the long-term rate impact to each customer group according to the rates analysis model. Generally, the model is set to have energy costs allocated based on energy share and operations costs allocated based on the number of customers. Figures 22–27 below show the seasonal and annual model rates, under a buy-down rather than high renewable stabilization strategy, as compared to Xcel's rates. Xcel's forward rates are taken as annual rates from the Baseline report. The rates analysis model splits them into customer segments by applying the 2010 ratio. Rates are in nominal dollars.

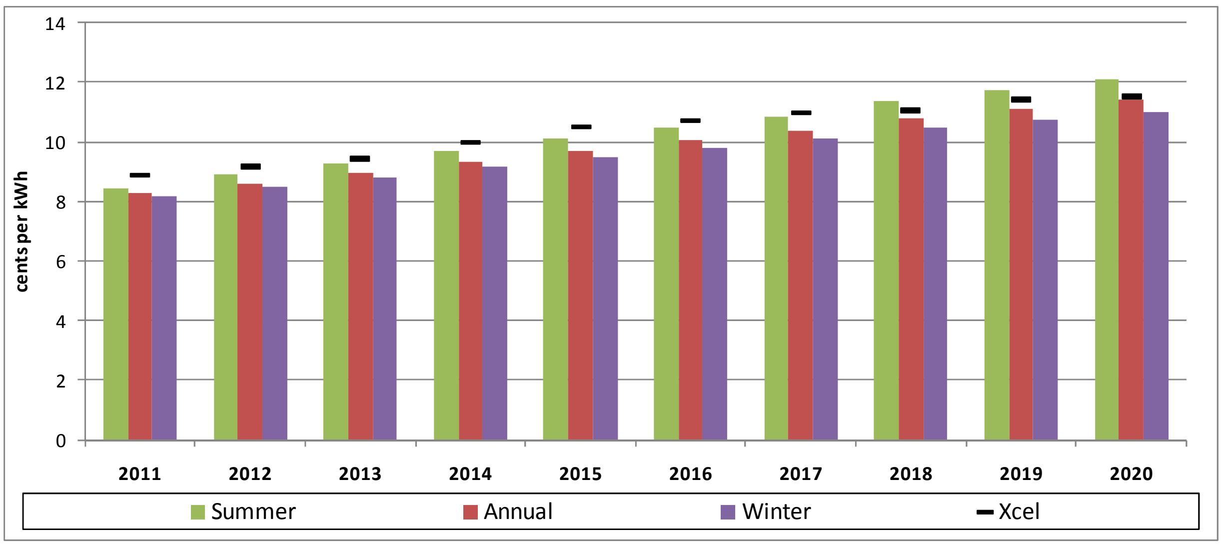


Figure 23: City of Boulder Seasonal and Annual Composite Rates

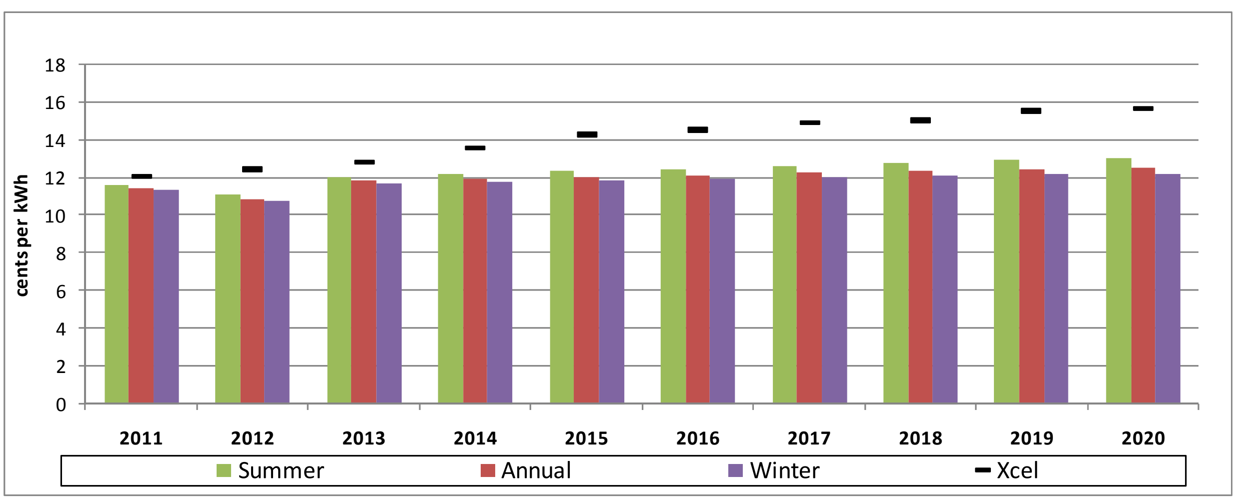


Figure 24: Residential Seasonal and Annual Composite Rates

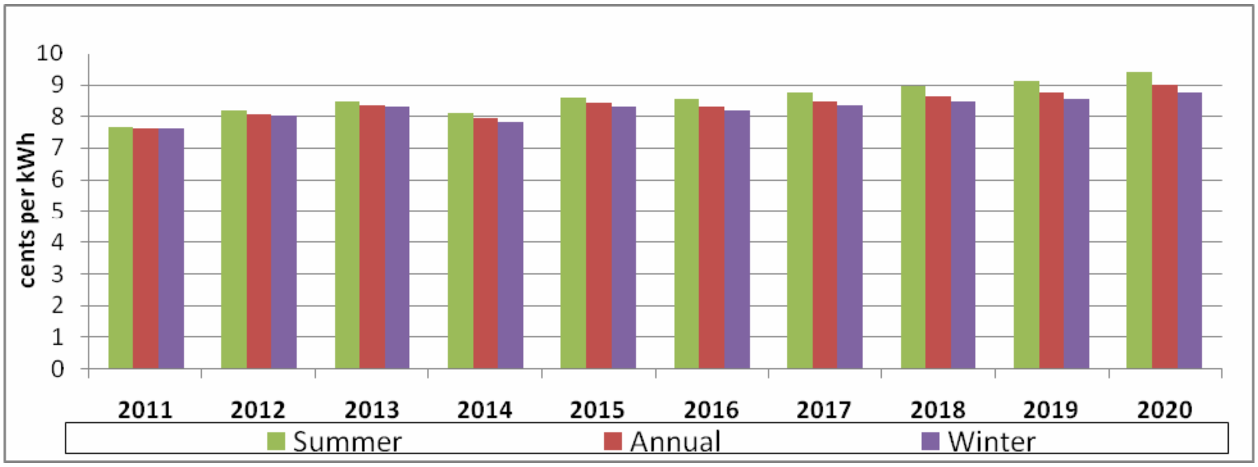


Figure 25: Low Income Residential Seasonal and Annual Composite Rates

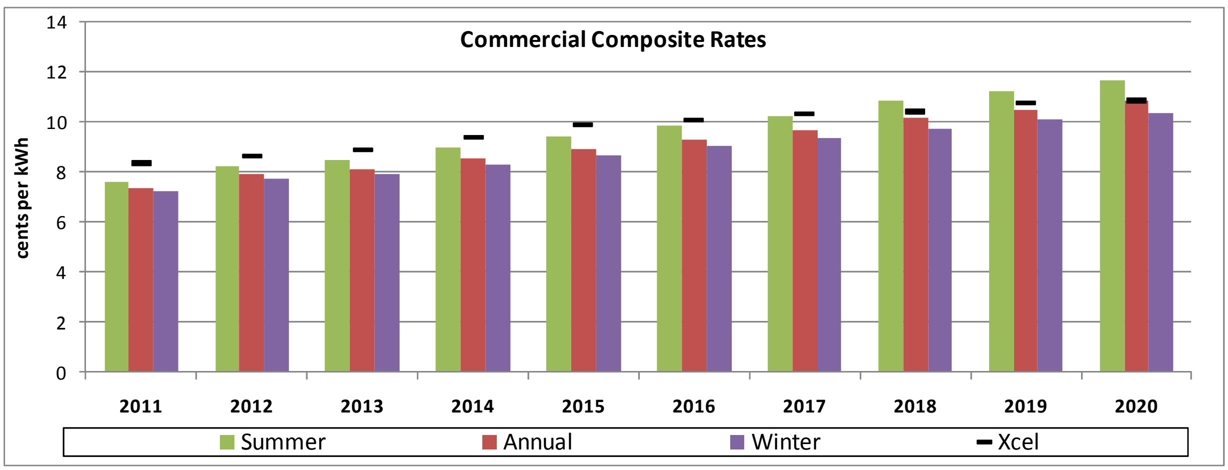


Figure 26: Commercial Seasonal and Annual Composite Rates

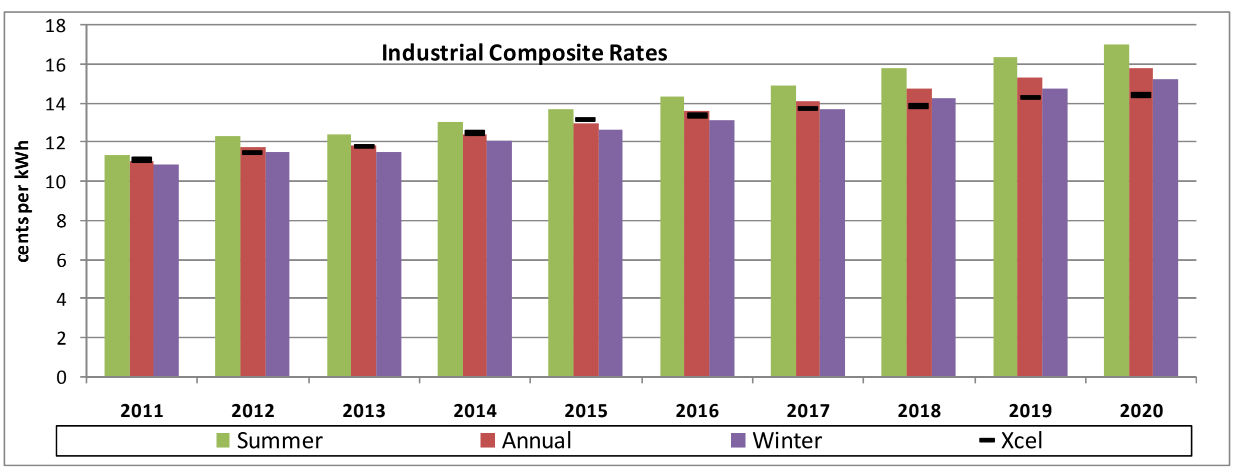


Figure 27: Industrial Seasonal and Annual Composite Rates

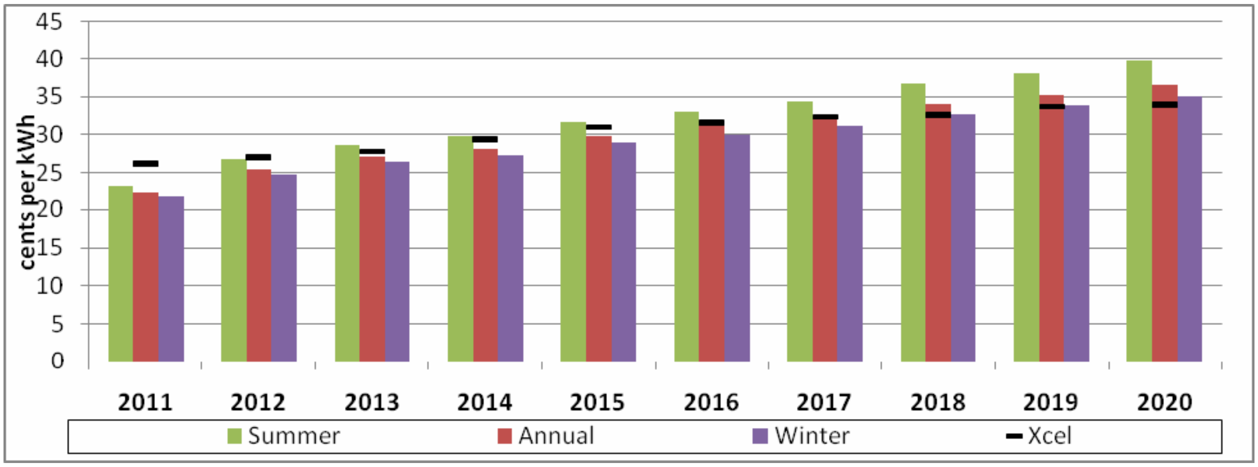


Figure 28: Other/Streetlight Seasonal and Annual Composite Rates

7 Conclusion

At the direction of the City, this study focuses on the feasibility of the creation and initial operation of a conventional municipal utility. The study shows that a municipal utility would be both feasible and financially sustainable. Based on the cost and rate models, the municipal utility would allow the City to meet its goals of rate stability, reliability of service, and lower carbon impact:

- The municipal utility's rate appears to remain competitive against the incumbent's during the first 10 years. As a caveat, the municipal utility could be more competitive based on several factors: the incumbent utility does not project a carbon tax in its rates; energy prices and heat rates are difficult to predict beyond 4 years; and the bond financing proposed in the model is very conservative and does not include opportunities for early repayment.

- The creation of a municipal utility could present many options not currently available, such as the use of alternative transmission, diverse resources, and enhanced localization.

- Adding renewable resources could further reduce the City's exposure to market price volatility, while allowing the City to reduce its carbon emissions by nearly 50 percent, largely through increased wind and natural gas.

Attachment A

Model Results

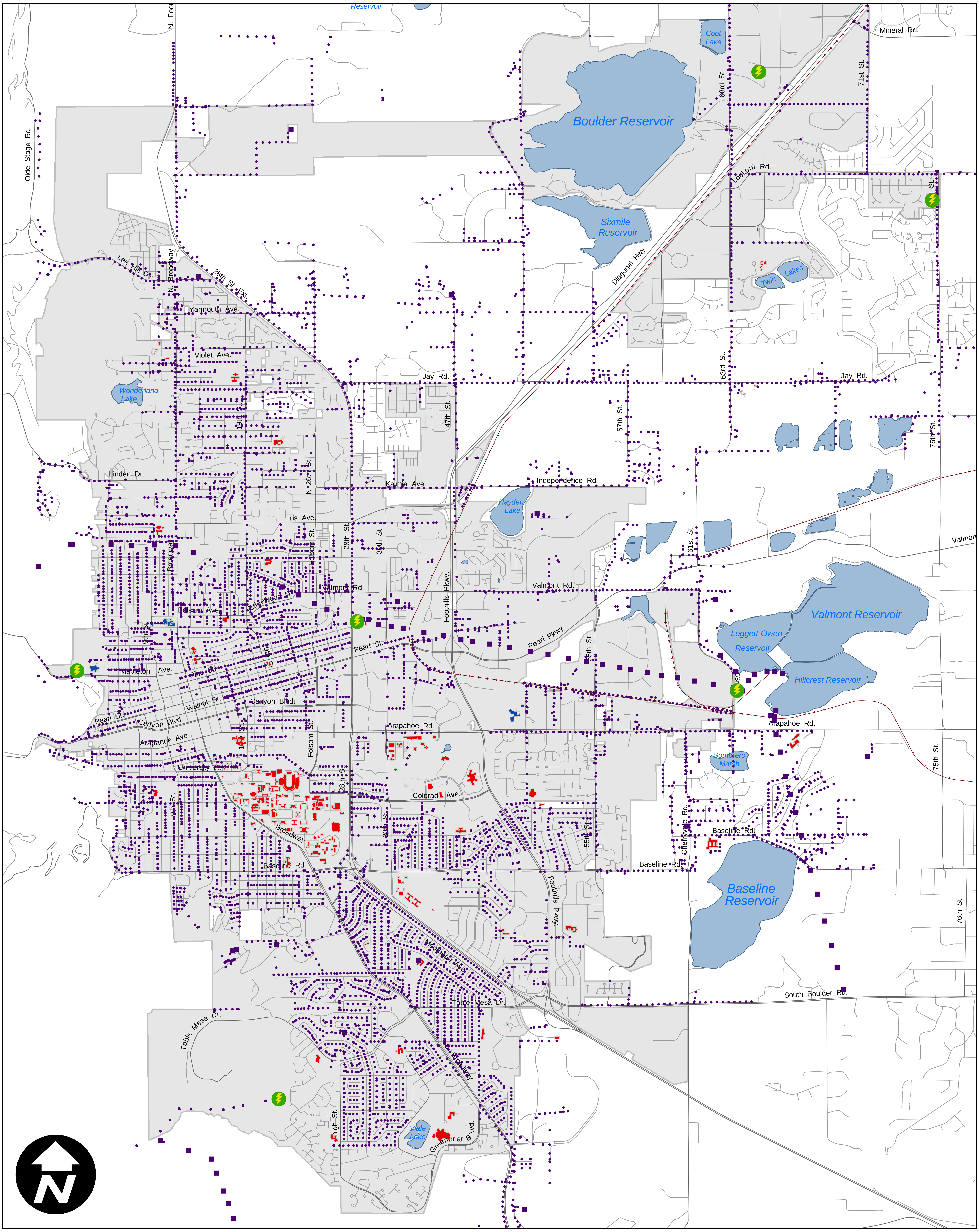
[See June 14, 2011 Staff Memo Attachment F: Summary Cost Model and Rate Comparison]

Attachment B

Maps

Utility Pole and Power Substation Locations

CITY OF BOULDER



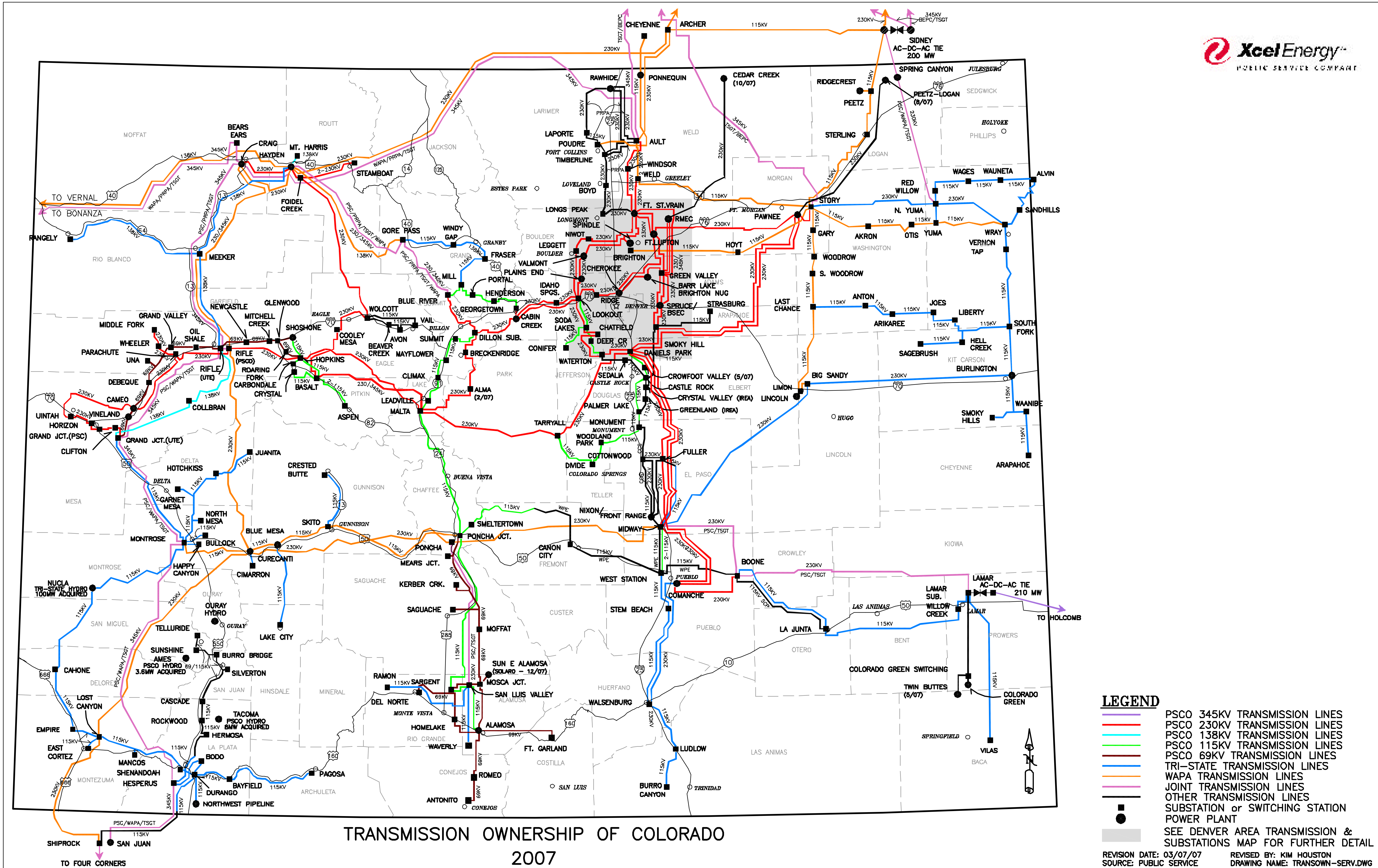
Legend

- Power Substation
- Tower
- Pole
- Hospital
- School
- City Limits

0 0.35 0.7 1.4 Miles

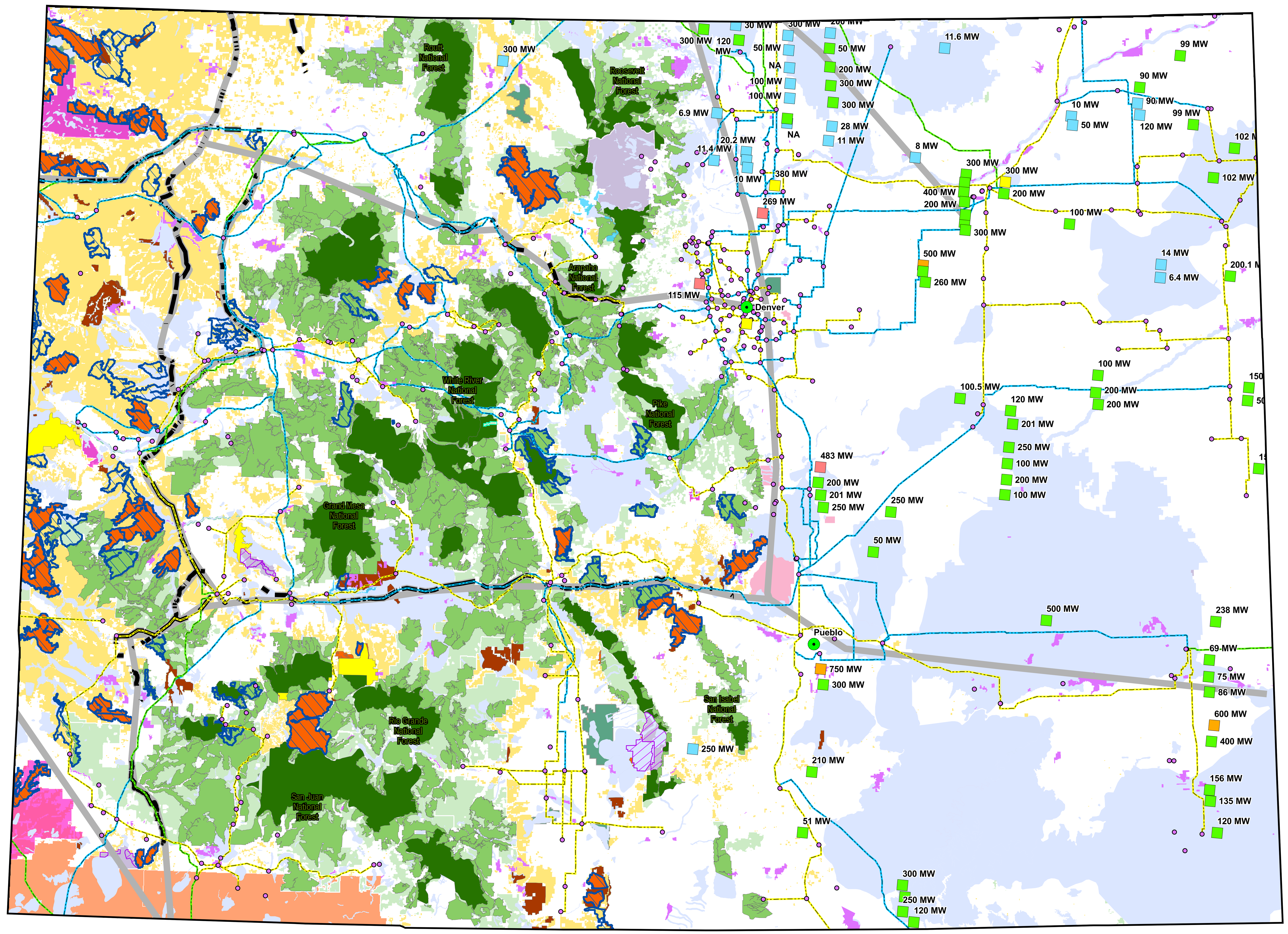
Utility pole data collected from 1993 aerial photography inventory. Data has not been checked for accuracy or completeness. No updates have been made since the original data collection.

Map printed July 23, 2010



Xcel Energy
PUBLIC SERVICE COMPANY
TRANSMISSION OWNERSHIP OF COLORADO
2007
LEGEND
PSCO 345KV TRANSMISSION LINES
PSCO 230KV TRANSMISSION LINES
PSCO 138KV TRANSMISSION LINES
PSCO 115KV TRANSMISSION LINES
PSCO 69KV TRANSMISSION LINES
TRI-STATE TRANSMISSION LINES
WAPA TRANSMISSION LINES
JOINT TRANSMISSION LINES
OTHER TRANSMISSION LINES
SUBSTATION or SWITCHING STATION
POWER PLANT
SEE DENVER AREA TRANSMISSION & SUBSTATIONS MAP FOR FURTHER DETAIL
REVISION DATE: 03/07/07
SOURCE: PUBLIC SERVICE
REVISED BY: KIM HOUSTON
DRAWING NAME: TRANSOWN-SERV.DWG

Comprehensive Regional Transmission Planning Data
Colorado (Map 1)



Map Legend

Existing Transmission Network *(Not to Scale)*

- Substation*
- <= 115 kV*
- 115 - 230 kV*
- 230 - 345 kV*
- 345 - 500 kV*
- Potential Energy Corridors on Federal Lands⁞
- Likely Continuation of Energy Corridors on all Lands⁞

Grid Interconnection Requests (Queues) by Generation Type† MW Specified Unless Unknown

- Wind
- Solar
- Hydro
- Coal
- Gas
- Unknown
- Other

Land Use Designations

- Bureau of Land Management (BLM)
- BLM (Areas of Critical Environmental Concern)
- BLM (Wilderness Study Areas)
- BLM (Wilderness)
- US Forest Service (USFS)
- USFS (and additional) Inventoried Roadless Areas⁞
- USFS (Wilderness)
- National Park Service (NPS)
- NPS (Wilderness)
- US Fish and Wildlife Service (USFWS)
- USFWS (Wilderness)
- National Monument
- State Wildlife Area Boundaries⁞
- National Recreation Area
- National Wildlife Refuge
- Bureau of Indian Affaris
- Department of Defense

Proposed Wilderness and Other Sensitive Landscapes

- Proposed Wilderness Area ‡
- Potential Conservation Areas⁞

0 20 40 60 80 Miles

Sources

* Global Energy Decisions, LLC (2007).
† Public Service Co of Colorado, WAPA, Pacificorp, Public Service Co. of New Mexico, Tristate (January 2008).
‡ Southern Rockies Conservation Alliance (2008).
⁞ USFS (2008); Southern Rockies Conservation Alliance Inventory of Roadless Areas (2008).
⁞ Colorado Division of Wilderness (2008).
⁞ Colorado Natural Heritage Program (2008).
⁞ Departments of Energy and Interior (Bureau of Land Management) (2007).
⁞ Departments of Energy and Interior, Draft West-Wide Energy Corridors PEIS, Figure 2.2-5 at page 2-19 (2007).

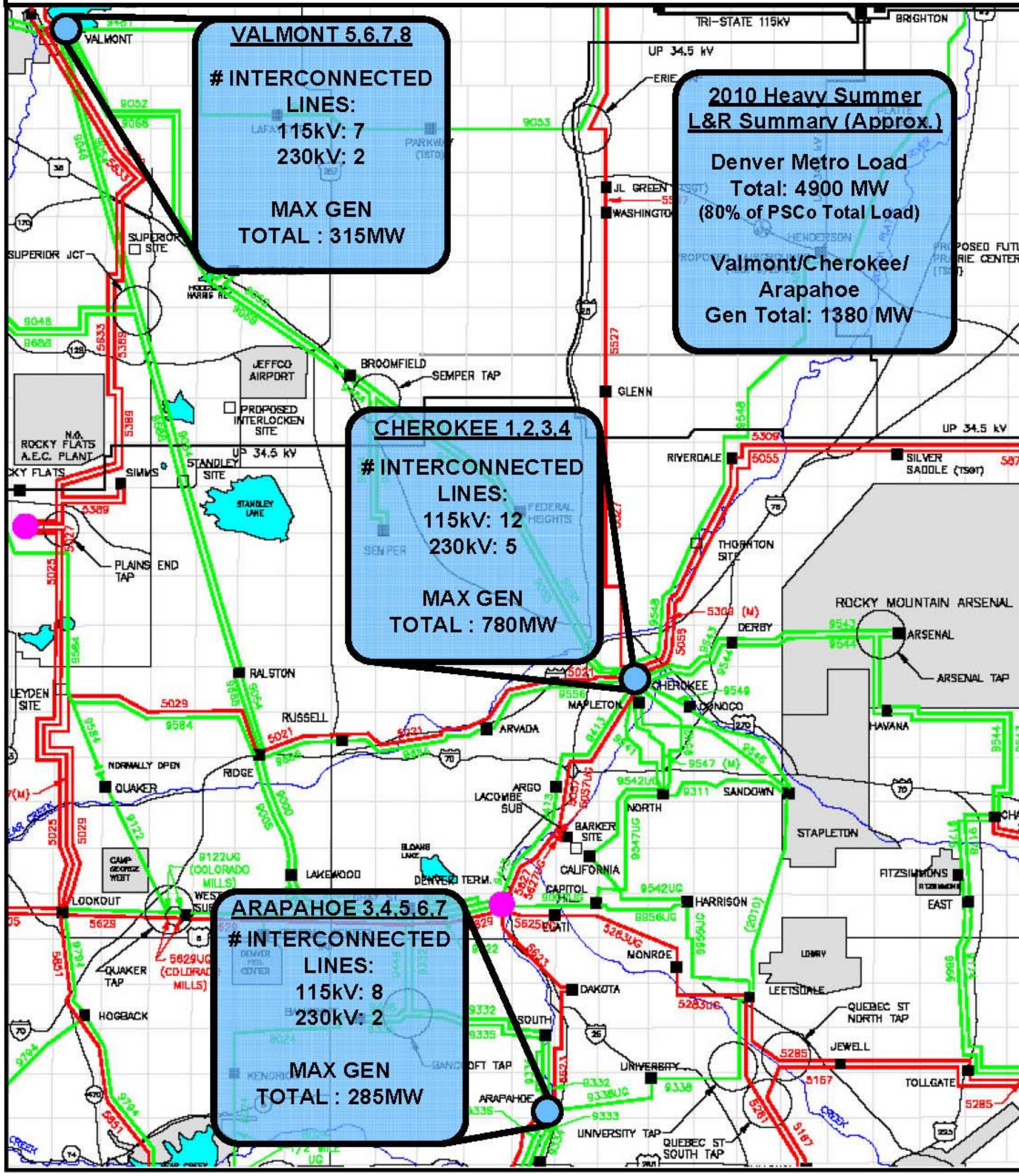
Western Resource Advocates

USE Utility System Efficiencies, Inc.

Date: 06/03/08

Attachment A

2010 Denver Metro Area PSCo Load and Resources



Attachment C

Model Documentation

Robertson - Bryan, Inc.
Solutions for Progress

1942 Broadway • Boulder CO 80302
Phone (303) 938-3088 • Fax (303) 938-6850

MEMORANDUM

Date: May 14, 2011

To: Ms. Yael Gichon, Project Manager – City of Boulder

From: Nils E. Tellier, P.E.

Project: Boulder Municipal Utility

Subject: Energy and Cost Model Documentation

Executive summary

This energy and cost model was developed for the feasibility study of the Boulder Municipal Utility. It provides a flexible platform, allowing the user to run various analyses and view the results instantly for:

- Transmission Charges
- Wholesale energy costs
- Renewable portfolio and cost impact
- Annual debt service on stranded cost
- Financial model for debt service
- Total operating cost
- City revenue requirement
- Financial feasibility

The model provides a 10-year forecast of the municipal utility operations costs and energy trades, with a granularity level of an hour for the energy calculations and one month for the cost calculations.

Introduction

The City of Boulder has contracted Robertson-Bryan, Inc. (RBI) to develop, among other tasks, a cost model to forecast various key elements of the municipal utility operation. Results from the model are used to validate the feasibility of a municipal utility. Rather than seeking precision, the model uses a conservative approach to minimize risks associated with the decision-making process.

The costs are derived from off-peak and on-peak energy use.[1] Accordingly the energy model uses a granularity of one hour for the energy calculations. Hourly calculations are aggregated to monthly and to annual. The cost model has a granularity of months since energy rates vary monthly.

The versatility of the model allows the users to run diverse scenarios for renewable portfolio, localization, financing etc over a time period of 10 years.

Model Presentation

System Requirement

Microsoft Excel Version:	2007 or newer
Computer memory:	4 GB minimum, 8 GB recommended. ReadyBoost Cache recommended
Computer CPU:	Next Generation (i-5 Quad-Core or better) recommended
Hard Disk space:	95 MB minimum

General Model Structure

The model consists of two inter-linked Excel files:
- The Energy model
- The Cost model

The energy model feeds the annual renewable resource installed capacity and the monthly energy data to the cost model. The cost model is designed to provide the main user interface. While the user may be drawn to the use of the cost model only, it is important to maintain both files open and linked for accurate results.

Both spreadsheets have color-coded tabs:
- Dark Blue: Calculations only, no input or results
- Green: User input, no results
- Dark Red: User input and significant results
- Light Red: Worksheet is not complete

[1] In the Western Energy Coordinating Council (WECC) territory, On-Peak hours are from hour ending (HE) 7:00 am to HE 11:00 pm, Mountain Time, Monday through Saturday except NERC Holidays.

User input

User inputs have been categorized as "fundamental" and "variable". The spreadsheets are not protected and it is important for the user to verify that an input value does not inadvertently overwrite a formula.

Energy Model Input

Fundamental inputs are entered into the Energy Model, and entail the basic set-up variables such as:

Fundamental Input	**Worksheet**
City load profile	Load Input
Transmission and primary distribution losses (distribution losses)	Load Input
Load annual growth	Load Input
PV-Solar hourly profile (percent of installed capacity)	Renewables
Wind generation hourly profile (percent of installed capacity)	Renewables
"Other" generation hourly profile (percent of installed capacity)	Renewables
Renewable Resources Installed Capacity	Renewables
Renewable Resource Firming	Renewables
City-owned hydropower hourly generation	Renewables

Cost Model Input

Variable inputs, including all cost inputs, are entered in the Cost Model. They are the parameters that the user may want to change in order to seek intermediate results. Cost model inputs entail:

Variable Input	**Worksheet**
Transmission Rates	NITS Rates
Wholesale Energy Rates (On-Peak and Off-Peak)	Energy Rates
Wholesale Energy Trade Margin	Energy Rates
Natural Gas Rates	Energy Rates
PV Solar Rates	Energy Rates
Wind Rates	Energy Rates
"Other" Generation Rates	Energy Rates
Hydropower Rates	Energy Rates
Firming Resource Capacity Rates	Energy Rates
Firming Resource Heat Rate	Energy Rates
Utility Operations Costs (1st year)	Cost Data
Staffing and salaries	Cost Data

Variable Input	Worksheet
Distribution Asset Valuation (acquisition cost)	Cost Data
SmartGrid City Cost	Cost Data
Start-up Costs	Cost Data
Taxable or non-taxable bond by cost	Cost Data
Stranded Cost input	Summary
Inflation rate	Summary
Public Purpose Program fund	Summary
Payment In Lieu Of Taxes	Summary
Working Capital Requirement	Summary
Selection of Acquisition Costs	Summary
Rate Parity with XCEL average retail rates	Summary
Bond Financing Parameters	Summary

Model Description

This section describes each worksheet function and key assumptions. The calculations and results span between calendar year 2011 and 2020. The 2011 start year was selected because it allows the model to synchronize with the calculated acquisition costs, reported City usage and current energy rates.

Energy Model

"Load Input" Worksheet

The user enters the following input:

- Transmission and Primary Distribution losses in cell C2

- Annual City load growth in cell C5

- City aggregated load, in the form of annual hourly strings ("8760") for each year.

Tip: several 8760 loads can be found at row 8776, columns E, F, G and I. The user can copy and paste-value an 8760 into the range E12:E8773. Load growth will be applied for each subsequent year unless the user chooses to enter other 8760's in those years, thus overwriting the formulae.

- The 49 and 56 percent load utilization profiles have a peak demand of 240 MW repeated each day. The base load is 40 MW and the total annual energy varies according to the percent load utilization.

- The Nexant profile has a limited occurrence of the peak demand. It is based on the Fort-Collins aggregated load.

- The actual 2010 City load was provided by Xcel. The aggregate of substation readings may have a +/- 25 percent error margin.

- 8760 City load must be in units of MW (or MWh per hour)

Assumptions:

- The model does not track Daylight Saving Time (DST) long and short days. It is essentially in Standard Time except that On/Off Peak normally follows DST. This caveat should have no measurable influence since the long and short days fall on Sundays (off-peak rate all day).

- The load input uses 8,760 hours per year. Leap years are handled in the Hourly Energy tab.

"Renewables" Worksheet

The user enters the generation profile for solar (local and off-site), wind, "Other", and city-owned hydro.

The 8760 for City-owned hydroelectricity is entered in kilowatts (or kWh per hour) of production.

Solar, wind and "other" renewable generation are entered as percentage of the installed capacity, in 8760 format.

Annual installed capacity of renewable resources can be entered in the cell range O6 to V 15. Off-site resource can be firmed by entering a 1 in cells P22, S22 or V22.

Assumptions:

- The model assumes that City-owned hydroelectricity is readily available to the municipal utility, i-e that there is no outstanding long-term power purchase agreement (PPA) with XCEL or another party.

- PV Solar and wind profiles are not averaged. Although the same profile is repeated year after year, the intermittency provides a truer picture for any firming activity.

- At this stage, the "Other" profile follows the wind profile. This is user-changeable. The "Other" resource is applied the carbon emission of Waste/biogas generation in the Cost Model.

"Hourly Energy" worksheet

This worksheet processes the hourly load and resources between 2011 and 2020. There is no user input however the hourly data allows a detailed review of load balancing. The calculations follow these steps:

- Hourly determination of the on-peak and off-peak load and local renewable resources.
- Determination of the hourly load net of local resources (Network Load) that must be served from the grid
- Determination of the hourly wholesale purchase: net load augmented by the transmission and primary distribution losses.
- Determination of the hourly generation from off-site renewable resources, if applicable.
- Determination of the Firming Resource (natural gas generation), if applicable.
- Calculation of the hourly Supplemental Market purchases and sales such that resources match the load within a megawatt.

Assumptions:

- Leap years result in a 24-hour pattern offset after February 29. December 31st is a pattern repeat of December 30th.
- For the determination of peak rates, NERC holidays are accounted for in 2011 and 2012 only. Subsequent years do not account for NERC holidays. This results in six erroneous peak days each year. The resulting error is minimal and leans on the conservative side.
- Load, renewable and firming resources are accounted in KW whereas Wholesale Purchases and Supplemental Market trades are accounted in MW. This assumption follows standard scheduling procedures and result in imbalances less than 1 MW.
- The model assumes that scheduled load matches forecasted load, thus eliminating large uninstructed imbalances. In actual situations, uninstructed imbalance is expected on a regular scheduling basis but most of it cancels out each month to a large degree. Modeling large imbalance at this point seems purely speculative.
- Firming resource is located on the grid and subject to transmission charges. The City may elect to have intra-muros firming resources but the approximation made in the model leans on the conservative side of transmission charges.

"Monthly Energy" Worksheet

This worksheet aggregates the hourly calculations to monthly, following the same layout. There is no user input.

"Annual Energy" Worksheet

This worksheet aggregates the hourly calculations to monthly, following a summary result-driven layout. There is no user input.

Cost Model

This document presents the worksheets in increasing order of complexity.

"Energy Rates" Worksheet

The user can update all or portions of the monthly rates between January 2011 and December 2040:

- Supplemental Energy:
  - Trade Margin, cell F6. Trade margin is added to the rate for supplemental purchases, subtracted from the rate for sales. Typical values range from $0.50 to $1.00 per MWh.
  - On-Peak rates, range E11:E370.
  - Off-Peak rates (Wrap), range F11:F370
  - Average rates (7x24), range G11:G370. This dataset is not used since the model track on and off-peak trades only.
- Natural gas rates: range I11:I370.
- Renewable rates: range L11:V370.
- Firming resource:
  - Capacity rate, range X11:X370, is a fixed contractual monthly cost to have available the firming capacity.
  - Heat rate, range Y11:Y370, is a fixed contractual efficiency measure used to calculate the natural gas consumption for the electrical energy generated.

Tip: The user can enter a renewable rate in the first row (range L11:V11) only and it will be increased annually for inflation, unless the formulae were overwritten with specific rates.

Assumptions:

- Current market energy and gas rates are in nominal dollars. They have been augmented annually by the inflation rate. This may present a risk of double accounting for inflation if the rates were originally published in nominal dollars, the error leans on the conservative side.

- Delivery costs are not included in the natural gas cost calculations. It is assumed that the gas is priced at delivery point (burner tip).

- Renewable rates are augmented annually to account for inflation.

- Capacity rates track the rate of natural gas. Inflation is already built in the natural gas rates.

"NITS Rates" Worksheet

The user enters the transmission rates in this worksheet. Transmission rates are provided by the Open Access Transmission Tariff (OATT) filed each year by the transmission utility with FERC. The user can change the values in columns E through S.

The transmission rates are applied to the maximum peak demand, according to the schedule percentage in column D.

Tip: The user can enter a rate for 2011 (column E) and it will be adjusted for inflation in subsequent years, unless the formulae were over-written by user-entered rates.

Assumptions:

- Network Integration Transmission Service (NITS) is modeled for transmission and ancillary service costs. Point-to-Point cost modeling can be the object of separate modeling for the purpose of case by case generation planning.

- This model follows only the OATT filed by XCEL in 2010.

"Monthly Energy" Worksheet

This worksheet looks for monthly energy data from the energy model and calculates the monthly cost for energy resources and transmission. There is no user input.

Assumptions:

- Transmission charges are calculated from the load-related wholesale purchases under NITS tariff (load, not generation, pays for transmission).

"Network Load" Worksheet

This worksheet determines the monthly peak demand in MW for network purchases. The peak demand is used for the calculation of transmission charges. There is no user input in this worksheet.

Tip: Transmission rates are in $/kW. The model calculates the costs according to demand but displays these costs in the form of energy rate ($/kWh or $/MWh).

"Bond Calc" Worksheet

This worksheet performs the bond cash flow calculations for taxable and non-taxable bonds. Taxable bond calculations are from column E to V; Non-taxable bond calculations are between columns Z and AQ. Both types of bonds use the same calculation methodology. There is no user input in this worksheet. Columns A, B and C are used by the rate model and should not be moved or deleted.

Parameters are imported from other worksheets and shown on rows 2 to 11. The year is divided in as many fractions as there are coupon payments.

Coupon payment starts after capitalized interest payments, until the maturity date plus one period. Coupon payment is calculated as the par value interest payment.

The bond retirement payment starts after capitalized interest payments. There is only one retirement payment per year. It is calculated as the par value principal payment. The total of retirement payments has to match the par value. the sum of principal and interest is a fixed annual amount, in nominal dollars.

Fund available is the par value, against which are charged the underwriting fee and other financed items (eg: acquisition, stranded and start-up costs, operating reserve etc).

Bond repayment is subtracted from the bond retirement balance such that, at maturity date, the retirement balance becomes zero.

Bond retirement balance starts at the par value and declines from the retirement payments.

Cash reserve is the sum of the operating reserve and debt service reserve.

Interest payment is made at the savings rate from the debt service reserve and half the operating reserve.

Assumptions:

- The initial costs for the utility are divided into two bonds, a taxable and a non-taxable bond.

- Funds available from the bonds are disbursed on the first day; therefore they do not contribute to the cash reserve or interests earnings.

- Interests are compounded as many times as there are coupon payments in a year (typically twice per year). This assumption leans on the conservative side.

- Interests are used to offset operations costs. Strategies such as re-injecting interests into the cash reserve are not considered at this stage.

"Cost Data" Worksheet

This worksheet compiles and determines several of the initial and operating costs. It contains user inputs.

- Utility operations costs (range B5:R52) allow the user to enter the cost by budget item.
    - Budget items are grouped by cost category.
    - Some cells are color-coded according to the staffing table. It is recommended not to overwrite the formulae.
- Staffing is shown between columns U and AE. This table allows the user to specify number of staff for each position as well as the salary selected (Column AE), which is used in the operations cost table.
    - Staffing includes shared positions with other City Utilities.
    - This table is based on the February 2007 study conducted by the City of Boulder. Salaries have been updated to 2011 using Salary.com.
- The distribution asset valuation (range AG4:AM25) is copied from the Asset Inventory and Valuation study. It provides the detail of Original Cost, Book value, Replacement Cost and Replacement Cost New Less Depreciation.
    - SmartGrid City acquisition cost is a user input in cell AI26.
- The city bond calculation table (range AG37:AJ52) serves three purposes:
    - Summarize the acquisition and stranded costs, and operating cash reserve.
    - Allows the user to enter the start-up cost items (cells AI47:AI50)
    - Calculates the taxable and non-taxable bond financing, based on user input (cells AJ39 to AJ50)
- Depreciation parameters entail a term (cell AL 27) and a percentage salvage value (Cell AL 28) applicable to the entire asset valuation.
- Distribution System Upgrade and undergrounding budget is entered in cell D54.
- Xcel retail rates are entered in the range D61:M61

Tips: In the utility operation cost input, it is only necessary to input the 2011 data, subsequent years will be adjusted for inflation. Color-coded cells contain formulae referring to the staff salary calculation.

Assumptions:

- Staffing assumes that the utility start with own staff from day 1, rather than using outside contractors.
- Utility operations cost itemization and values are empirical and support criticism.
- Staffing salaries use the maximum value from the salary ranges.
- Operating cash reserves consist of a full year reserve for utility operations and a partial year reserve for wholesale energy and transmission costs (based on the Working capital requirement input).

"Annual Energy" Worksheet

This worksheet displays the annual summary of energy load and supply, energy cost, Renewable resources, and comparative power content labels between Boulder and XCEL. There is no user input in this worksheet.

"Summary" Worksheet

This worksheet is intended to be the main user interface, with a section of key inputs and results all on one page. Inputs are located between E5 and E21, results are displayed below row 27. Given the links between the cost and energy models, some inputs require an exhaustive recalculation of all the hourly energy data and results display after a delay; the user needs to wait until the recalculations have completed, as displayed by MS Excel in the lower right corner of the screen.

User inputs entail:

- Stranded Cost Estimate (Cell E11)
- Bond Parameters for taxable and non-taxable bonds are user-entered in the table range D15:E21.
- Inflation, P3 funding, PILOT and working capital requirement are user inputs in cells E5:E8.
- The Target Debt Service Coverage and Revenue Margin are entered in cells E9 and E10. These values determine the Revenue (Sale of Power) on an accrual (Income) basis. Revenue Margin is increased annually by the inflation rate.
- Distribution Acquisition Costs to be used for the bond calculation are user-selectable in the table range I19:M22.

- Renewable Resources Installed Capacity (range N2:T20) allows the user to test various scenarios of local and off-site (i-e network or wholesale) renewable generation.
    - Input is imported from the energy model.
    - In this model, only off-site renewable can be firmed.
    - Firming is 100 percent of the installed renewable resource capacity.

The result section displays the following annual summaries:

- Renewable Portfolio Standard (RPS), with comparative results between Boulder and XCEL.
- Savings / Losses between the municipal utility and XCEL.
    - The savings or losses are calculated by comparing the municipal utility's to XCEL's revenues. XCEL's revenues are based on retail rates (row 40) times the total load (row 148).
- The Statement of Operations derives the rates and net income on an accrual basis.[2]
- The Utility Operating Costs is the City's revenue requirement on a cash basis. It entails:
    - Energy resource costs (local, wholesale and transmission).
    - Operations costs
    - Financial Costs (bond repayment, P3 fund and tax)
    - Rows 133 and 134 show utility's on-peak and off-peak unit costs.
    - A verification table shows the cash flow based on revenue and cost.
- The energy summary for the load and by resource type.

Important Notes

- The model contains a large number of calculations and care has been taken to review the model in detail. In the event that an error has been identified, please contact immediately:
  Mr. Nils E. Tellier, P.E.
  Robertson-Bryan, Inc.
  Email: nils@robertson-bryan.com
  Phone: (303) 938-3088

[2] Acknowledgement to the Financial Engineering Company – M. Hubbard, P.E.

- The calculation of emissions factor is not user-adjustable. The following parameters are used:
  - Biomass, waste and “Other”: 393 lb CO_{2e} / MWh
  - Geothermal: 1 lb CO_{2e} / MWh
  - Small Hydroelectric: 0 lb CO_{2e} / MWh
  - Solar generation: 0 lb CO_{2e} / MWh
  - Wind generation: 0 lb CO_{2e} / MWh
  - Coal generation: 2,168 lb CO_{2e} / MWh
  - Large Hydroelectric: 0 lb CO_{2e} / MWh
  - Natural Gas: 903 lb CO_{2e} / MWh
  - Nuclear: 0 lb CO_{2e} / MWh

EXECUTIVE SUMMARY

This rates analysis model was developed for the feasibility study and business plan of the Boulder Municipal Utility. It is constructed to be used in conjunction with the cost model and is designed so that the user can run various cost allocation and rate structures by customer segments. Instant results are shown in tabular and graphical form, as well as an invoice template.

The model brings in the 15 years of forecast data as set up in the cost model, including all operations costs and energy trades, with a granularity level of monthly calculations for cash flow, and seasonal and annual for rates.

INTRODUCTION

The City of Boulder has contracted Robertson-Bryan, Inc. (RBI) to develop, among other tasks, a rate analysis for operations as a municipal utility. The rate analysis model is designed to be used in conjunction with the cost model designed by RBI. The RateAnalysis file links to the cost model and utilizes all cost line item totals to determine the share of costs and associated rates for different customer segments. Xcel Energy (Xcel) currently has 27 different rate tariffs under adoption, this analysis condenses all customers into one of five groups; Residential, Low Income Residential, Commercial, Industrial, and Other / Streetlight. The Rate Analysis model has a granularity of months for cash flow and seasonal and annual for rates.

The versatility of the model allows the user to designate a percentage cost allocation for each line item of the cost model for each customer segment. It also allows the user to modify many parameters in the rate design. All user inputs are applied to all 15 years of data. The results output summarizes the rate design by customer segment for a selected year and produces tables and graphs of the seasonal and annual results for the full 15 years.

Additionally, the model includes an invoice template worksheet. The invoice was designed off of the current Xcel design to aid in demonstrating how the rates results link to the invoice to the customers.

MODEL PRESENTATION

SYSTEM REQUIREMENTS

Microsoft Excel Version:	2007 or newer
Computer memory:	4 GB minimum, 8 GB recommended, ReadyBoost Cache recommended
Computer CPU:	Next Generation (i-Quad Core or better) recommended
Hard Disk space:	95 MB minimum

GENERAL MODEL STRUCTURE

The full model consists of three inter-linked files:

- The Energy model
- The Cost model

- The Rates Analysis model

The rates analysis file pulls financial and load data from the cost model file, therefore, it is important to first work with the cost and energy models to set up the parameters for the analysis. Although the rates analysis file can operate without the other files open, it is advised at a minimum to have the cost model file open while working in the rates analysis file. If different energy and cost scenarios will be tested, it is important to have all three files open as the cost file feeds the energy file, and the results feed back to the cost file, which feeds the rates analysis file.

FILE DESCRIPTION

The Rates Analysis file is primarily designed to allocate costs to customer segments and to design the rate structure. Additional elements to the file are cash flow analysis and an invoice template. This section describes each worksheet function and assumptions. The calculations and results span between calendar year 2011 and 2025 as designed by the cost file.

Caution:

- ***Do not reorganize the order of the tabs in the workbook. Doing so will cause formulas to result in errors.***
- ***Worksheets are not password protected, therefore only change data in Inputs cells which are highlighted in blue.***
-

High Level Organization:

The "Boulder" worksheet brings in the cost and energy data in monthly detail into a cash flow analysis table for all months between 2011 and 2025. The cash flow table is designed to match the cost line items in the cost file, divided into energy and operations costs. The monthly costs are then summarized into seasons for each year. The Summer and Winter seasons are then further divided into various rate derivations based on user input.

There is a worksheet for each customer segment; Residential, Residential Low Income, Commercial, Industrial, and Other/Streetlight. Each customer worksheet is exactly the same design as the "Boulder" worksheet, however the costs in the cash flow tables are based on user-defined percentages of the "Boulder" worksheet.

The "Input and Summary" worksheet is where the user controls the cost percentages and rate design. The table on the left summaries all cost items and rate derivations that the user can manipulate, highlighted in blue. The rest of the tables and graphs are summary results and comparisons to Xcel.

Based on the rates the user defined, the user can also see a sample invoice using the "Invoice Template" worksheet. There is a small user input section where the user can specify parameters for the invoice.

The last worksheet of the file is the “PSCo rates” worksheet. This worksheet holds the comparison data for Xcel taken from the Baseline Analysis and 2009 Annual PSCo report data. This data is fed to the “Input and Summary” worksheet for comparisons.

Worksheet Detail:

1. “Boulder” worksheet

** Caution – there are no inputs on this sheet. Any changes need to be made in the “Input and Summary” worksheet.*

This worksheet serves two functions, cash flow analysis and rate derivation.

Cash Flow

The monthly cash flow table starts in cell B78. The cost file operations line items are in column C and D and there is a subsequent column for each month starting with January 2011 and ending January 2026. The table is designed so that the energy data in rows 82 and 84 is under the heading of the corresponding month. The cost data for the month is listed in the following month’s column. The reason being invoices for expenses and revenues for the current month will not be received until the following month. For example, the Boulder energy consumption for January 2011 is in cell G82, however all the costs associated with January 2011 are under February in column H.

Assumptions for Cash Flow Table:

- Resource and Transmission costs are as derived in the energy and cost files.
- Distribution, General Administration, Billing, Scheduling, and Metering costs take the annual total and divide by 12 to get monthly amounts.
- Debt Service is as derived by the cost file. The model assumes principal repayment starts in 2013 and takes place each July, and the coupon payments happen twice a year in January and July.
- Taxes are based on percentages set in the cost file and multiplied by monthly total costs (excluding debt repayment).
- Revenue (row 39) includes power invoices, taxes, and interest.
- The Accumulated Balance (row 145) assumes a target of 150 percent of next month’s bills.
- The Power Reserve column is the funds necessary to have in the bank in addition to invoice revenue in order to pay current bills and have 150 percent of next months’ anticipated costs covered.
- Start-up costs (including legal and engineering) are included as a starting balance in cell G149.
- Interest rate is set at 1.5 percent (cell F141).

Rate Derivation

The cash flow data is summarized by cost category and into seasons starting in row 156. Seasonal definitions follow Xcel’s current structure:

- Summer is June 1 through September 30
- Winter is October 1 through May 31

The seasonal data is pulled into the rate derivation tables. The tables are organized with Winter in orange on the top starting in row 3 and Summer below in yellow starting in row 38. The tables starting in L3 summarize the costs for each year and by season for utilization in the main table on the left, starting in cell C3.

Assumptions for Rate Derivation

Basic organization of the table is to determine the rates, which is dollars (column I titled 'Amount') divided by a basis (column C titled 'value'). Row 2 summarizes the user inputs for the table (what year to analyze and how to allocate Transmission and Distribution costs). The Balance column J starts with the total amount needed and reduces as each cost category's costs are removed, ultimately getting to zero in cell J34. Below details the cost line items and rate derivation for each cost category in the table:

- **Customer Charge**
    - Costs includes General Administration, Billing, Scheduling, Metering, and Debt Service
    - Revenue collection is a lump sum amount for each month; total costs divided by number of customers.
    - Number of Customers is a user input and is currently set to the quantity defined in the Baseline Analysis.
- **Taxes**
    - Costs are a percentage set in the cost model of monthly energy costs (not including debt service)
- **Transmission**
    - Costs include Transmission and Ancillary Services.
        - Revenue collection is by either total energy (kWh) or by peak demand (kW). The user selects either 'energy' or 'demand' in the user input.
- **Distribution**
    - Costs include Distribution include operations and equipment. They do not include any acquisition costs assumed for utility startup.
    - Revenue collection is either by total energy (kWh) or peak demand (kW). The user selects either 'energy' or 'demand' in the user input.
- **Resources**
    - Costs include all Resource costs (renewable, firming, supplemental, etc.)
    - Revenue is tiered
        - The first Tier serves a certain amount of energy at a user-defined rate. The user also defines the maximum allowance for the Tier.
        - The rest of the energy is served in Tier 2, split 60 percent at the on-peak rate and 40 percent at the off-peak rate.

- The user defines the off-peak rate and the residual dollars to collect determine the on-peak rate. Off-peak rates should be set by the user so that on- and off-peak rate decrement accordingly.

2. “Residential”, “Residential Low Income”, “Commercial”, and “Industrial” worksheet

**Caution – there are no inputs on this sheet. Any changes need to be made in the “Input and Summary” worksheet.*

These sheets serve the same purpose as the “Boulder” tab, to review cash flow and rate derivation. Cash flow is included here for information purposes, however it is assumed that cash flow will only be reviewed on a Boulder wide basis and not at the customer level. The cash flow at the customer level can be a good source to determine where rates are under or over performing when in actual utilization.

These worksheets are the exact same structure as the “Boulder” worksheet. The only difference is that the cost line items that make up the cash flow table (starting in row 78) are based on percentages of the “Boulder” worksheet (whereas the “Boulder” worksheet draws its data from the cost file). The percentages in column F for each customer segment are user inputs on the “Input and Summary” worksheet.

3. “Input and Summary” worksheet

This worksheet serves two purposes, to set cost allocation and rate derivation by customer segment and to review results. The design is to allow the user to make modifications and see the impact of their change in the same location.

Inputs:

All inputs are highlighted in light blue.

- **Rate Derivation Inputs:**
    - Select calendar year: cell C3
    - Number of Customers: cells D6:H6
        - Currently set to Baseline Analysis 2009 data, which matches the 2009 PSCo Annual report
        - Used to split the Customer Charge
    - Tier 1 maximums: cells D7:H8
        - Maximum monthly energy consumption allowed to receive the Tier 1 rate
        - Two rows of this item; Summer and Winter seasons
    - Tier 1 rates: cells D9:H9 and D11:H11
        - Rate applied to energy allowed into Tier 1, expressed as cents per kWh
        - Two rows of this item; Summer and Winter seasons
    - Tier 2 off-peak rates: cells D10:H10 and D12:H12
        - Rate applied to off-peak Tier 2 energy. Tier 2 energy is 40 percent of the energy above the Tier 1 quantity.
        - Two rows of this item; Summer and Winter seasons
        - On-peak rates are not set by the user. The on-peak rate is the resulting rate of residual resource dollar amount to collect divided by 60 percent of the energy above the Tier 1 amount.
        - It is possible not to have any Tier 2 energy, in other words, total energy consumption is within the Tier 1 amount.

- Transmission Basis: cells D13:H13
  - These costs can be set to collect on either a total energy basis or by peak demand. Because residential and other small loads are mostly all on energy meters, these customer groups are set to 'energy' basis. Commercial and Industrial customers are assumed to have interval reading meters and are therefore set to 'Demand'.
- Distribution Basis: cells D14:H14
  - Same as Transmission Basis
- Energy Share of Boulder Load: cells D15:H15
  - This percentage divides the total Boulder consumption (kWh) and Peak (kW) data by customer segment.
  - Currently set to Baseline Analysis ratio share of 2010 data, confirmed by similar percentages in the 2009 PSCo Annual report.

- **Cost Allocation Inputs:**
  - All line items are the same titles as used in the cost file. Each line item's total cost is allocated to each of the customer segments as dictated by the user's percentage inputs.
  - If the total percentage inputs per line do not add up to 100 percent, the total in column I will turn pink.

Results Review:

The rest of the columns to the right of the Input table are the results. Xcel comparison rates are reported from the Baseline Analysis on an annual composite basis for Boulder. The Boulder rate was portioned out to each customer segment based on 2009 PSCo Annual report ratios.

- **Summary of Boulder Customer Power Rates**: columns K:R
  - This table summarizes the rates by customer and by season for the year specified. The seasonal and annual power costs, energy, and resulting composite rates are summarized.
  - Row 46 shows the Xcel comparison rates
    - These are pulled in from the "PSCo Rates" tab.
  - The graphs below show the seasonal and annual rates by customer compared to the Xcel rates.
- **Composite Rates**: columns V:AB
  - The first table is for annual rates by customer segment
  - The second table is for Summer season
  - The third table is for Winter season
  - All years are included in this table (where as the Summary of Boulder Customer Power Rates table in column K:R is one year specific)
- **Customer Tables and Graphs**: columns AD:AT
  - One table for each customer segment summarizing seasonal and annual composite rates compared to Xcel annual rates.
  - Graphs next to the tables for different representation of tabular data.

4. “Invoice Template” worksheet

The purpose of this worksheet is to view a sample of a customer invoice. There is a small amount of user inputs in column B, the rest of the worksheet calculates based on the rate derivation and cost allocation set in the “Input and Summary” worksheet.

Half of the data in the invoice template is hard value place holders, such as Customer Name and Invoice number.

5. “PSCo Rates” worksheet

The purpose of this worksheet is to summarize the data utilized from the Baseline Analysis report as well as the 2009 PSCo Annual report. The data is used as a basis for the rate design for each customer segment.

Attachment D

OATT Report

Table of Contents

List of Tables

EXECUTIVE SUMMARY

- Under Federal Energy Regulatory Commission (FERC) Order 888, utilities that own or operate facilities used for interstate transmission are obligated to provide transmission, balancing and ancillary services to their wholesale customers on a comparable basis to that which the utilities provide those services to themselves. Xcel Energy (Xcel) is such a utility.
- By municipalizing its utility, the City of Boulder (City) would become a wholesale customer of Xcel.
- Wholesale transmission under Open Access consists of:
  - Point-To-Point (OATT Part II, P2P) transmission: from a generator to a non-designated load.
  - Network Integration Transmission System (OATT Part III, NITS): for designated loads such as the City's.
  - Ancillary Services alone (OATT Part IV, A/S)
- Wholesale transmission costs are based upon the City's monthly peak demand. The effects of transmission costs on the City's energy rates are related to the City's load management and localization of resources.
  - Under a 56 percent load utilization, the transmission costs will be approximately:
    - NITS and A/S: 0.7 cents per kWh ($7.00 / MWh) of load
    - P2P and A/S: 0.95 cents per kWh ($9.50 / MWh)

INTRODUCTION

The City of Boulder (City) has contracted Robertson-Bryan, Inc. (RBI) for the development of a municipal utility business plan. A significant recurring charge to the operation of a municipal utility is the cost incurred from wholesale transmission.

Currently, the City is a retail customer of Xcel Energy (Xcel). Xcel provides and controls all aspects of energy procurement, generation, transmission and delivery, and provides these services to its retail customers under a bundled package with a single monthly invoice. Should the City elect to create its own utility, it would take control of its energy procurement and become a wholesale transmission customer of Xcel. Wholesale transmission is used to "wheel" energy from remote generators to local substations. Wholesale transmission is regulated by the Federal Energy Regulatory Commission (FERC), under its Open Access Transmission Tariff (OATT).

The purpose of this report is to describe the wholesale transmission system and the OATT; determine what applies to the City, should it municipalize its electric utility; and quantify the expected charges. This report is intended as a summary and clarification to the OATT rather than as a reference to or a replacement for the OATT.

TRANSMISSION VERSUS DISTRIBUTION: GENERAL DESCRIPTION

Transmission and Distribution are the two connected systems that together deliver power from generators to consumers. Transmission systems include high-voltage lines that carry power from generators to local substations. Power is converted to lower voltages at the substations and then delivered to the end user. The delivery of power from the substation to the end user is called the Distribution System. Transmission and Distribution systems for Boulder are currently owned and operated by Public Service Company of Colorado (PSCo), a subsidiary company of Xcel.

If the City is considering ownership of the Distribution System under a municipal utility, it may need to contract PSCo for wholesale transmission services. This report will focus on the transmission service options available to the City.

WHOLESALE TRANSMISSION SERVICES

FERC Order No. 888 requires utilities that own transmission lines to provide open access to transmission on a comparable basis to that in which the owners provide transmission services to themselves. The overall goal is to increase opportunities for competition in the power market, bringing more efficient and lower-cost power to consumers. The OATT is the federal document that defines the guidelines for transmission service.

Simply stated, all transmission owners are required to honor transmission requests and be compensated under rates published annually and approved by FERC. However, there is a finite amount of room on the transmission lines in any single hour, termed "transmission capacity". To the extent there is capacity available, the transmission owner must make service available to requesting users provided they have an active service agreement with the transmission owner.

There are two basic types of transmission service: Point-To-Point (P2P) and Network Integration Transmission Service (NITS).

- Any transmission service for sales of resources (generators) to non-designated third parties must do so under a P2P arrangement. Under P2P, a specified amount of capacity is reserved for a defined Point of Receipt on which the resource will enter the transmission system and the Point of Delivery where the power is to be delivered.
- The other option, which the City would more likely use, is NITS, in which the customer defines Network Load and Network Resources to serve the load. These two services are not mutually exclusive and the City could elect to arrange the majority of its transmission service under NITS but also have P2P service for certain resources.

In addition to the basic transmission of power flow from resources to serve end user load, the transmission owner is responsible for the reliability of the transmission system, including providing Ancillary Services (A/S). A/S includes control and resolution for differences in supply and demand, line voltage fluctuations, and overall maintenance. While certain A/S would need to be purchased from PSCo, others could be procured from third parties or be self-supplied.

Table 1 below summarizes all OATT service schedules and their applicability to the City under NITS and P2P transmission service.

Table 1.Summary of OATT Schedules

Schedule	Description	Service Type	NITS	P2P
Schedule 1	Scheduling, System Control, & Dispatch	Ancillary	x	x
Schedule 2	Reactive Supply and Voltage Control	Ancillary	x	x
Schedule 3	Regulation & Frequency Response	Ancillary	x	x
Schedule 4	Energy Imbalance	Ancillary	x	x
Schedule 5	Operating Reserve – Spinning Reserve	Ancillary	x	x
Schedule 6	Operating Reserve – Supplemental Reserve	Ancillary	x	x
Schedule 7	Firm P2P Transmission Service	Transmission		x
Schedule 8	Non-Firm P2P Transmission Service	Transmission		x
Schedule 9	Generator Imbalance	Ancillary		x
Schedule 10 - 12	*Not applicable to PSCo*			
Schedule 13	NITS Transmission Service	Transmission	x	
Schedule 14	P2P Transmission Losses	Transmission		x

As a caveat, PSCo would evaluate the City's creditworthiness should the parties enter into a service contract(s). Creditworthiness is an annual determination of unsecured credit to extend, and/or the collateral to request, in order to ensure compensation for services rendered.

Transmission Service Compensation

Transmission owners are required to provide transmission service at just and reasonable rates. The rates cover the costs of providing transmission service, as well as a return on the associated capital invested. The total cost of providing transmission service, including the return, is referred to as the utility's Transmission Revenue Requirement (TRR) and is published each year on May 15th and effective June 1st. For PSCo, the TRR published in June 2010 is net revenue of $145,704,396 divided by an average system peak demand of 6,127,954 kW, yielding a rate of $23.777 per kW. This annual rate yields the monthly service rate of $1.981 per kW-month.

In addition to transmission, the City must also secure Ancillary Services. Like other utilities with interstate transmission, PSCo is required to offer all A/S to transmission customers and rates are published in Schedules for each service under the OATT tariff.

In both transmission and ancillary services, it would be the City's responsibility to cover demand needs, inclusive of line losses. Although transmission lines deliver power at efficient high voltages, there are still transmission line losses. PSCo's published losses are currently 2.56% for the transmission system and 2.35% for primary distribution services. For example, The City may need 100,000 kilowatt (kW) for its load, but the energy procurement and delivery reservation will need to be for 105,000 kW to cover losses during delivery along the transmission and distribution systems.

Network Integration Transmission Service (NITS)

Definition: Allows the Network Customer (the City) to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in the same manner and treatment as PSCo services it Native Load. NITS also may be used by the Network Customer to deliver economy energy purchases to its load from non-designated resources without additional charge.

NITS cannot be used for sales of capacity and energy to non-designated load; P2P is available for such transactions. The following steps illustrate how the City would establish a NITS contract with PSCo:

Initiating Service

- Complete an Application for Service with deposit of one month's service cost
    - Deposit can be waived due to creditworthiness results
- Complete technical arrangements (meters / interconnection facilities)
- Meet creditworthiness
- Execute a Service Agreement

Network Resources

- Specified in Service Agreement
- Includes generation owned, purchased, or leased by the City to serve its Network Load
- Cannot include generation that is committed for sale to third parties
- Schedules of resources (net of sales on P2P) cannot exceed load
- Do not have to be physically connected to PSCo transmission system. Arrangements necessary for delivery of capacity and energy are the responsibility of the City

Network Load

- Specified in Service Agreement
- Load not physically connected to PSCo system can be included for service under NITS, or excluded and served under P2P service.

Billing

- OATT Schedule 13 – monthly coincident hourly demand * monthly service rate
    - Peak hourly usage on the PSCo system is determined and the demand of the City in that hour is the demand used in the monthly rate calculation.
    - Demand is always inclusive of line losses.
- For example, assume the coincidental load at the PSCo system peak is 240,000 kW for the City.
    - 253,000 kW * $1.981 = $501,298
        - 253,000 kW used instead of 240,000 kW to account for losses
        - $1.981/ kW is the monthly published service rate

POINT-TO-POINT (P2P)

Definition: For the reservation and transmission of capacity and energy from designated Point(s) of Receipt to designated Point(s) of Delivery. P2P is used for sales of energy and capacity from multiple generating units that are on the PSCo transmission system.

Initiating Service

- Same as NITS

Contract Information

- Non-Firm P2P
    - Reserved and scheduled on an as-available basis
    - Subject to curtailment or interruption before P2P Firm, NITS, or native customers

  - Contracts offered in hourly, daily, weekly, and monthly duration
    - Maximum contract length is one month
- Firm P2P
  - Reservation and curtailment priority is higher than non-firm P2P and equal to NITS and native customers.
  - Contracts offered in daily, weekly, or monthly durations

Billing

- OATT Schedule 7 for firm and Schedule 8 for non-firm
  - The rates are the same under both Schedules; however, Schedule 8 includes rates for hourly contracts, which are not available under Schedule 7 for Firm service.
- Calculation is reserved capacity kW * rate
  - The rate is determined by taking the TRR annual rate of $23.777 and dividing it by the applicable contract length.
  - For example, if the P2P contract is for monthly service, the rate is the same as NITS at $1.981. However, if it is weekly service, the annual rate of $23.777 is divided by 52 (weeks in the year) to use a rate of $0.457 per kW-week.
- For example, assume a reserved capacity of 253,000 kW for the City for one week:
  - 253,000 kW * $0.457 = $115,621
- OATT Schedule 14 – Transmission Loss Obligations
  - This schedule specifies options for satisfying transmission loss obligations. The option above in which it is included in the transmission service reservation calculation is used here for simplicity.

Ancillary Services (A/S)

Definition: Services necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission System.

PSCo would be required to provide, and the City would be required to purchase:

- Scheduling, System Control and Dispatch (Schedule 1)
- Reactive Supply & Voltage Control from Generators and other Sources (Schedule 2)

The City would be required to purchase or self-supply other A/S. The City could purchase these services from PSCo or a third party:

- Regulation & Frequency Response (Schedule 3)

- Energy Imbalance (Schedule 4)
- Operating Reserve – Spinning (Schedule 5)
- Operating Reserve – Supplemental (Schedule 6)

Because the City would presumably purchase power from generators that are in the PSCo transmission system, the City would also be required to purchase from PSCo or a third party:

- Generator Imbalance Service (Schedule 9)

The City would not be allowed to turn down PSCo's A/S services unless it could demonstrate that it had acquired the A/S from another source. If the City uses services that it does not reserve, PSCO would bill the City for the services at established rates in the service agreement.

Billing

All A/S are billed in the same manner as transmission service. The applicable rates are published in each Schedule in the OATT tariff. The demand basis for NITS is coincidental demand and reserved capacity is used for P2P.

Creditworthiness

Prior to becoming a transmission customer, an applicant must undergo a credit evaluation using commercially reasonable practices to determine the level of unsecured credit the utility is willing to extend for services. Evaluation criteria include but are not limited to:

- Review of Financial Statements
    - Audited statements for the 3 fiscal years most recently ended
- Rating Agency reports (if available)
    - Senior Unsecured Long Term Debt ratings issued by Standard & Poor's, Moody's Investors Service, Fitch Ratings, or other agreed source.
- References
    - Bank information and three major industry trade references
- Estimated Peak Load
    - Used to estimate highest 60 day credit exposure
- Other indicators of credit strength

Transmission service credit policies mandated by FERC, such as Large Generation Interconnection Procedure (LGIP) and Large Generation Interconnection Agreement (LGIA), may have different credit requirements. These apply to generating facilities over 20 MW.

Credit Evaluation

- Performed every 12 months, or more frequently if material adverse change in creditworthiness
- If determined the customer is creditworthy, an unsecured credit limit will be established
  - This must equal the historical, or estimated highest 60 day credit exposure.
  - Minimum unsecured Credit Limit for a public entity is $250,000
- If unsecured credit limit is insufficient, or unsecured credit denied, collateral or security will be required. Upon notification, the customer will have 2 days to provide collateral/security.
  - Acceptable forms of financial security are cash or letters of credit.

CONCLUSION

Should it choose to form a municipal utility, the City would need to make arrangements for the delivery of its power procurements. While the City is considering ownership of the Distribution System, it would likely need to contract with PSCo for Transmission service.

Of the two options available, NITS is the service that best fits the City's proposed business model, as it gives the most flexibility in economically scheduling and maintaining its resources to meet load. While most if not all load will be served under NITS, the City could also have P2P arrangements for sales of excess resources to third parties. In addition to transmission service, the City likely would also need to procure Ancillary Services from PSCo to ensure system reliability.

Assuming that the City procures NITS and all Ancillary Services from PSCo, the composite rate under currently published rates for an estimated City load of 1,396,324 MWh is 0.5 to 0.6 cents per kWh, at an annual cost of $6.6 to 9 million dollars. While the City could start off purchasing all required services from PSCo and later contract with other parties for ancillary services, it could further reduce its transmission costs by developing local generation. Having local generation and/or demand-side management can reduce significantly the amount of procured energy needed to travel along the Transmission System.

Attachment E

Asset Valuation

Boulder Municipal Utility

Feasibility Study

Addendum

Prepared for:

City of Boulder

Prepared by:

RBI Robertson - Bryan, Inc.
Solutions for Progress

August16, 2011

Introduction

This section summarizes the limits of project financed costs, bond interest and bonding amount before the financial feasibility shows a 10-year cumulative revenue break-even with Xcel Energy's projected revenues. The energy and cost models have been updated with increased income from the Public Purpose Program Fund (P^3 Fund), the Payment In Lieu Of Taxes (PILOT) and an annual development of photovoltaic solar.

Results Summary

The following table summarizes the break-even points between Xcel's projected 10-year cumulative revenue and the municipal utility.

Taxable Bond Interest:	7.00%	8.00%	9.00%	9.51%
Non-Tax. Bond Interest:	5.04%	5.76%	6.48%	6.85%
Max. Add'l Taxable Financing ($ million)[1]:	$ 94.84	$ 49.60	$ 14.88	$ -
Maximum Total Fund ($ million)[2]:	$ 317.74	$ 272.50	$ 237.78	$ 222.90
10-year Savings NPV ($ million)[3]:	$ 6.99	$ 7.03	$ 7.07	$ 7.09
10-year Cumulative Cash Reserve ($ million):	$ 28.35	$ 28.47	$ 28.56	$ 28.60
10-Year Average Rate Parity over / (Under) XCEL[4]:	-1.06%	-1.82%	-2.38%	-2.62%

Notes:

1. Maximum additional funding financed with taxable bond
2. Total fund includes taxable and non-taxable bond financing
3. Based on 10-year break-even of cumulative revenues between XCEL and the municipal utility
4. Based on Municipal Utility Revenue break-even at year 10

Table 1: Bond Rate and Funding Break-Even

The municipal utility shows a positive cash reserve in excess of $28 million (in 2020 dollars) under all scenarios when stabilized rates are derived from a revenue break-even in 2020 as shown in figure 1 below.

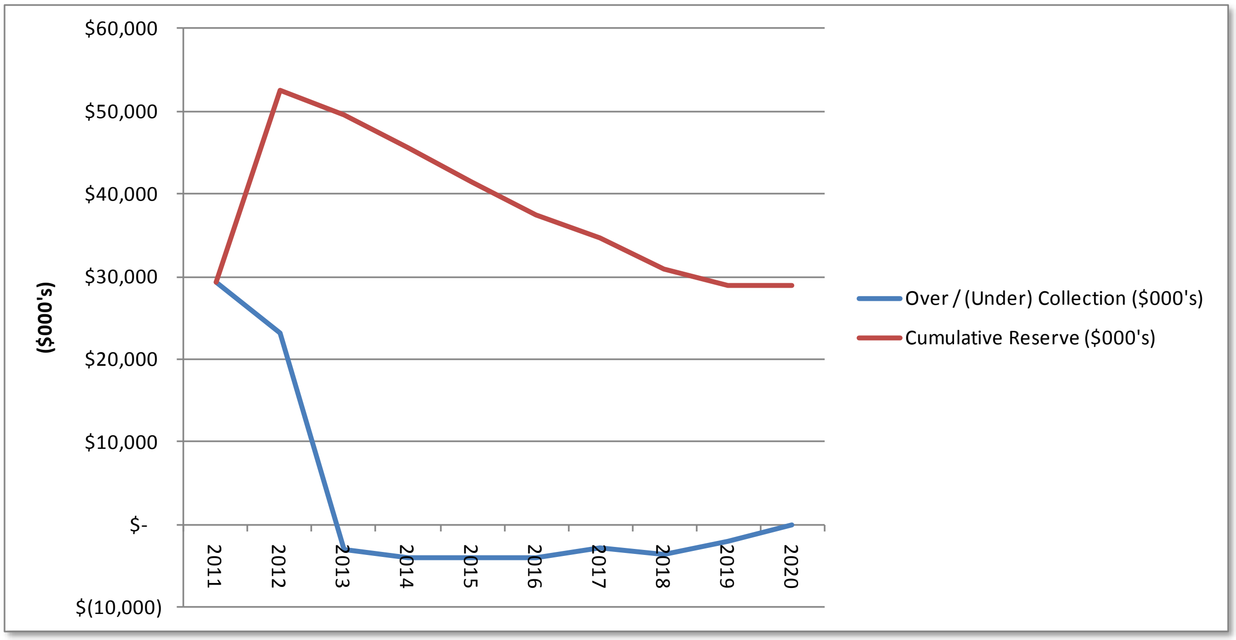


Figure 1: Utility Cumulative Reserve ($ 000's) – Base Case Example

Key Parameters

Energy Supply Portfolio

The energy and cost models were amended to include photovoltaic solar development (PV Solar), in addition to the city-owned hydroelectric generation. Wholesale market energy is used to supplement generation to cover the net short position (load minus generation). Table 2 below shows the deployment of PV Solar generation capacity in installed MW, and Figure 2 shows the energy make-up.

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
MW	2.23	4.46	6.69	8.92	11.15	13.38	15.61	17.84	20.07	22.30

Table 2: PV Solar Installed Capacity (MW)

PV Solar development is financed with a rebate program and a REC purchase similar to Xcel Energy's SolarReward Tier 1:

- Rebate: $1.50 per Watt installed, escalating at 2.5 percent per year
- REC purchase: 4 cents per kWh, escalating at 2.5 percent per year

PV solar development is funded from annual operation revenues only.

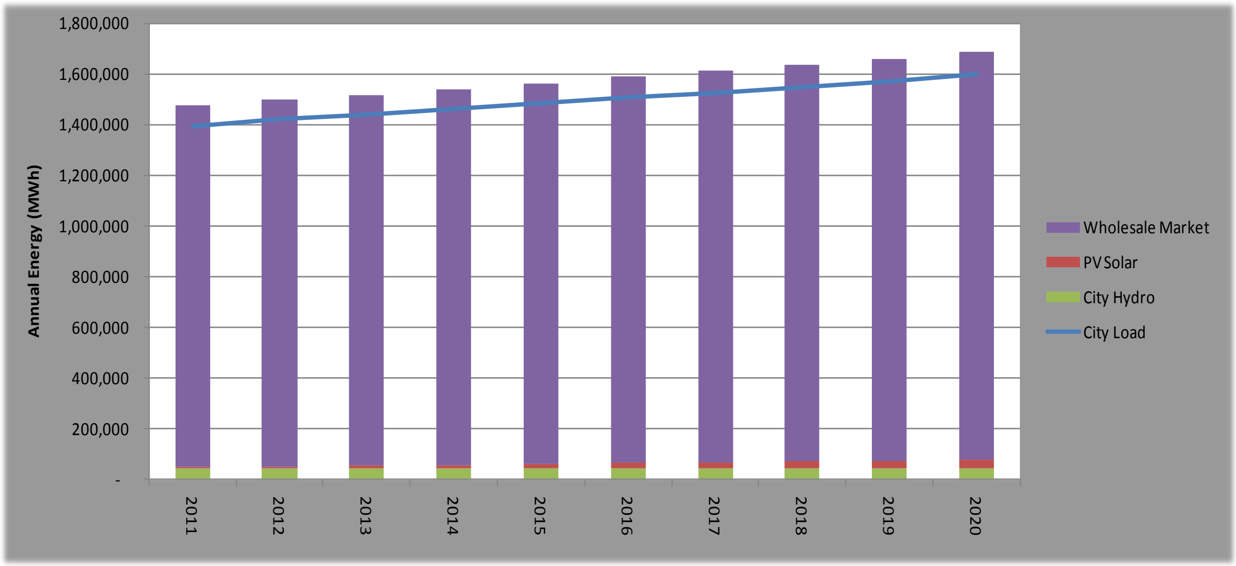


Figure 2: Annual Energy Portfolio

The solar development together with the city-owned hydropower give the municipal utility an advantage over the incumbent utility in relation to carbon emissions and renewable portfolio, would it procure the remaining of its energy from wholesale market. Table 3 below compares the RPS and carbon emissions between the City and XCEL Energy.

	2011	2014	2016	2018	2020
Local Renewable Resources:	3.3%	3.9%	4.2%	4.5%	4.7%
Boulder Renewable Portfolio:	17.9%	23.9%	27.0%	29.1%	40.2%
Boulder Emissions (lb CO2e / MWh):	1,433	1,326	1,265	1,168	1,086
Xcel Renewable Portfolio:	15.0%	20.7%	23.7%	25.7%	37.1%
Xcel Emissions (lb CO2e / MWh):	1,478	1,376	1,316	1,220	1,137

Table 3: Comparative RPS and CO_2 Emissions

Income In Lieu of Taxes

In addition to the deployment of PV solar generation, the models were amended to increase funds from PILOT and P^3 revenues. The Payment In Lieu Of Taxes was increased to assure a minimum annual revenue of $4 million to replace the Utility Occupation Tax. The public Purpose Program fund was increased to 7.5 percent of the Utility's operating cost for tax revenues to the City, Boulder County, Boulder Valley School District, as well as the Clean Air Program Tax and other programs (CAGID, UHGID and Forest Glen Parking). Figure 3 below illustrates the projected tax revenues.

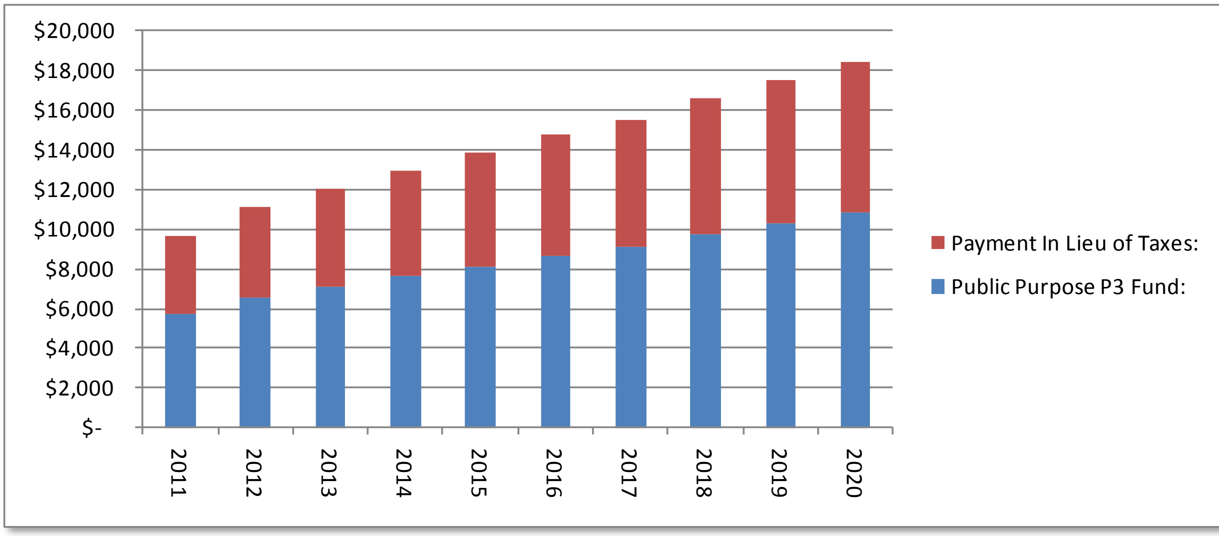


Figure 3: Projected Revenues from PILOT and P^3

Other Parameters

Other fixed parameters include:

- Minimum revenue margin of $5 million annually.
- Minimum Debt Service Coverage ratio of 1.5, as in the original feasibility study.
- Bond parameters: same as the original feasibility study, unless disclosed otherwise.

Composite rates for the utility are calculated:

- Based on the utility's operating revenues from an accrual or income basis
- Based on the utility cost from a cash basis.
- Stabilized rates are limited to a constant 4 percent annual increase. They are derived in this study such that the 10-year cumulative revenue difference between rate-based revenue and the utility cost of operation, on a cash basis, is zero.

Rate Distribution follows PSCO's 2009 distribution multipliers between rate payer categories, as table 4 shows below.

	Residential	Commercial	Industrial	Street Lights
Multiplier	136 %	94 %	125 %	295 %

Table 4: Composite Rate Multiplier by Customer Base

Table 5 shows the current retail rate projection by sector under Xcel Energy.

XCEL COMPOSITE RATES PROJECTION ($/MWh)					
Year	Residential	Commercial	Industrial	Other / SL	XCEL
2011	120.61	83.58	111.09	262.39	88.87
2012	124.31	86.14	114.49	270.42	91.59
2013	128.00	88.70	117.89	278.45	94.31
2014	135.38	93.82	124.69	294.52	99.76
2015	142.77	98.94	131.50	310.58	105.20
2016	145.23	100.64	133.76	315.94	107.01
2017	148.92	103.20	137.16	323.97	109.73
2018	150.15	104.05	138.30	326.65	110.64
2019	155.07	107.46	142.83	337.36	114.27
2020	156.31	108.32	143.97	340.03	115.17

Table 5: Retail Rates Projection under Xcel

Base Case

Savings from the municipal utility's annual income (on accrual basis) when compared to Xcel's rate-based revenue yield a 10-year Net Present Value (at a discount of 2.5 percent) of $40.25 million.

Figure 4 below compares the actual and stabilized composite rates to Xcel's projection. The rates exceed Xcel's projection in 2020 due to the financial cost of continuing PV Solar development.

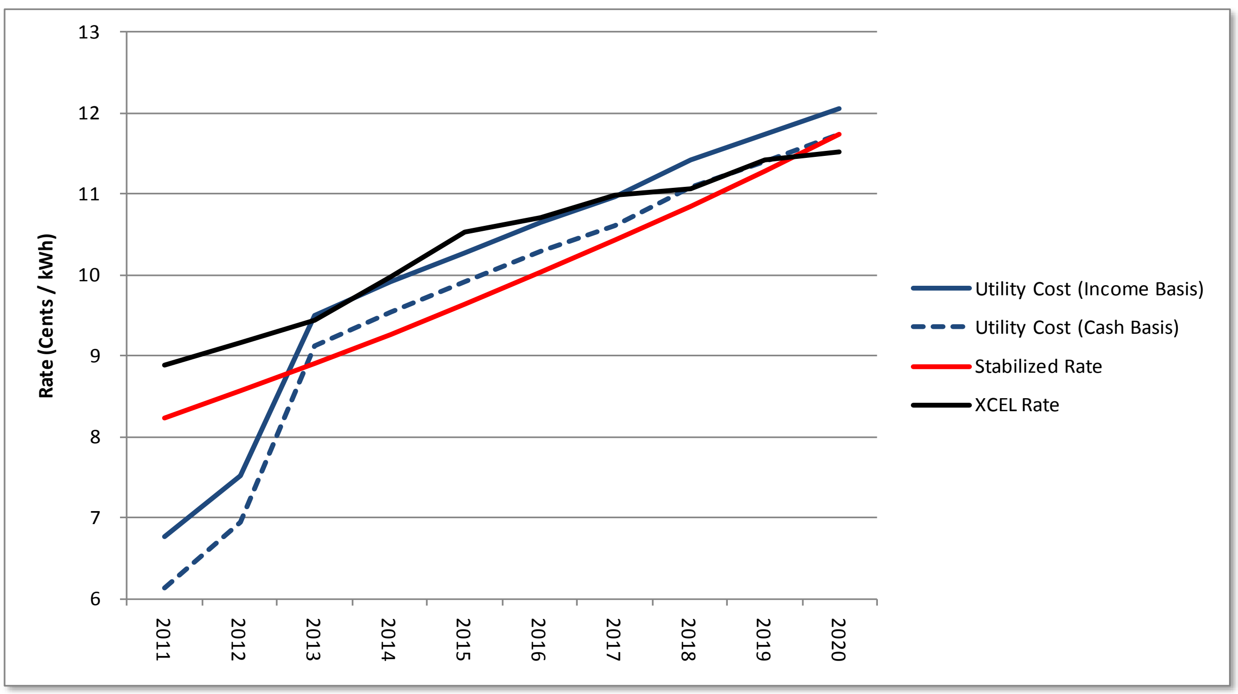


Figure 4: Composite Rate Comparison – Base Case

Based on the above composite rates and the current allocation shown in Table 2 above, the municipal utility could derive the following retail rates as shown in table 6 below.

COST MODEL STABILIZED COMPOSITE RATES ($/MWh)						
Year	Residential	Commercial	Industrial	Other / SL	City of Boulder	Xcel
2011	111.80	77.48	102.98	243.22	82.38	88.87
2012	116.27	80.58	107.09	252.95	85.68	91.59
2013	120.93	83.80	111.38	263.07	89.10	94.31
2014	125.76	87.15	115.83	273.59	92.67	99.76
2015	130.79	90.64	120.47	284.53	96.37	105.20
2016	136.02	94.26	125.29	295.91	100.23	107.01
2017	141.47	98.03	130.30	307.75	104.24	109.73
2018	147.12	101.95	135.51	320.06	108.41	110.64
2019	153.01	106.03	140.93	332.86	112.74	114.27
2020	159.13	110.27	146.57	346.18	117.25	115.17

Table 6: Retail Rate Allocation – Base Case

Figures 5 and 6 below illustrate the comparative rates between the composite (accrual basis), stabilized and Xcel's projection for the residential and commercial accounts.

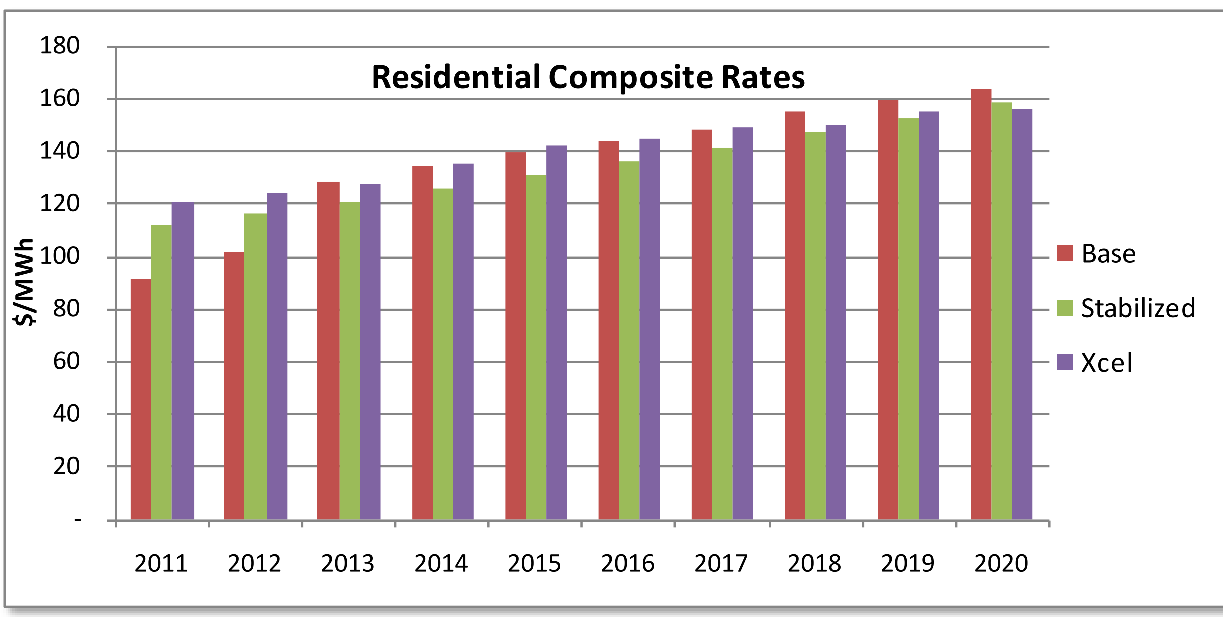


Figure 5: Projected Residential Composite Rates – Base Case

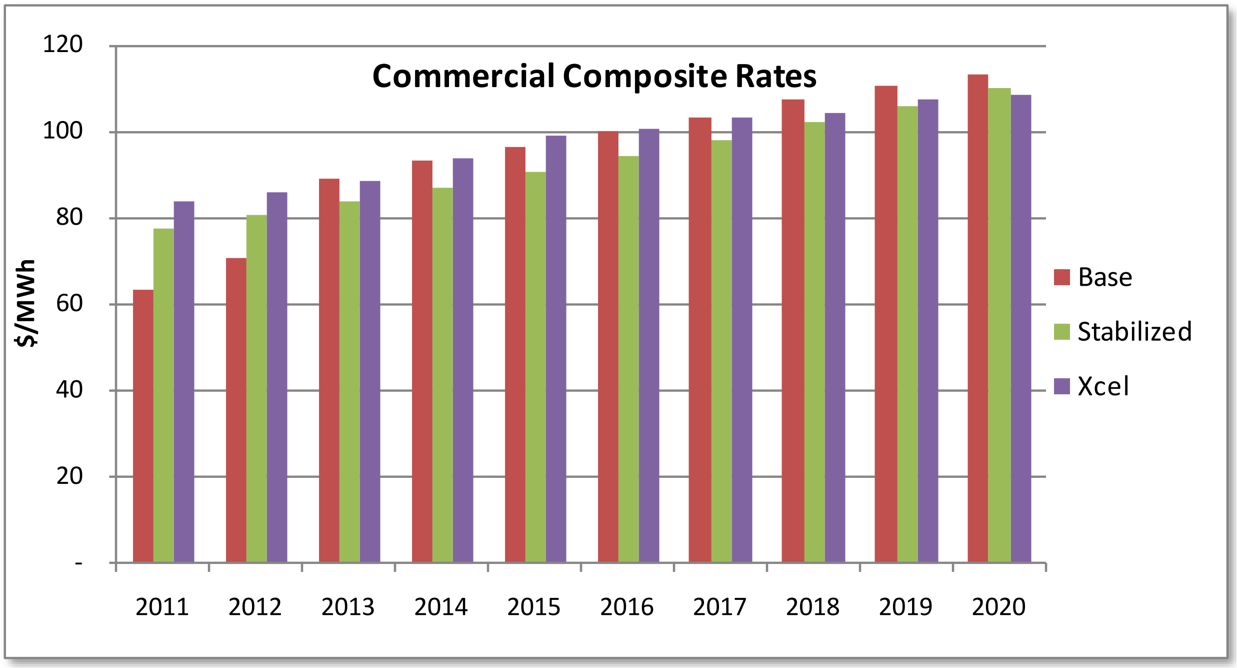


Figure 6: Projected Commercial Composite Rates – Base Case

Bonding Limit Feasibility

Maintaining a $5 million Minimum Revenue Margin

Under the above parameters, an additional $49.6 million in taxable bond financed capital brings the feasibility to a break-even with Xcel's forecasted cumulative revenues over 10 years. Under this scenario, the total project funding would be $272.5 million. Savings from the municipal utility's annual income (on accrual basis) when compared to Xcel's rate-based revenue yield a 10-year Net Present Value (at a discount of 2.5 percent) of $7 million.

Figure 7 below compares the actual and stabilized composite rates to Xcel's projection.

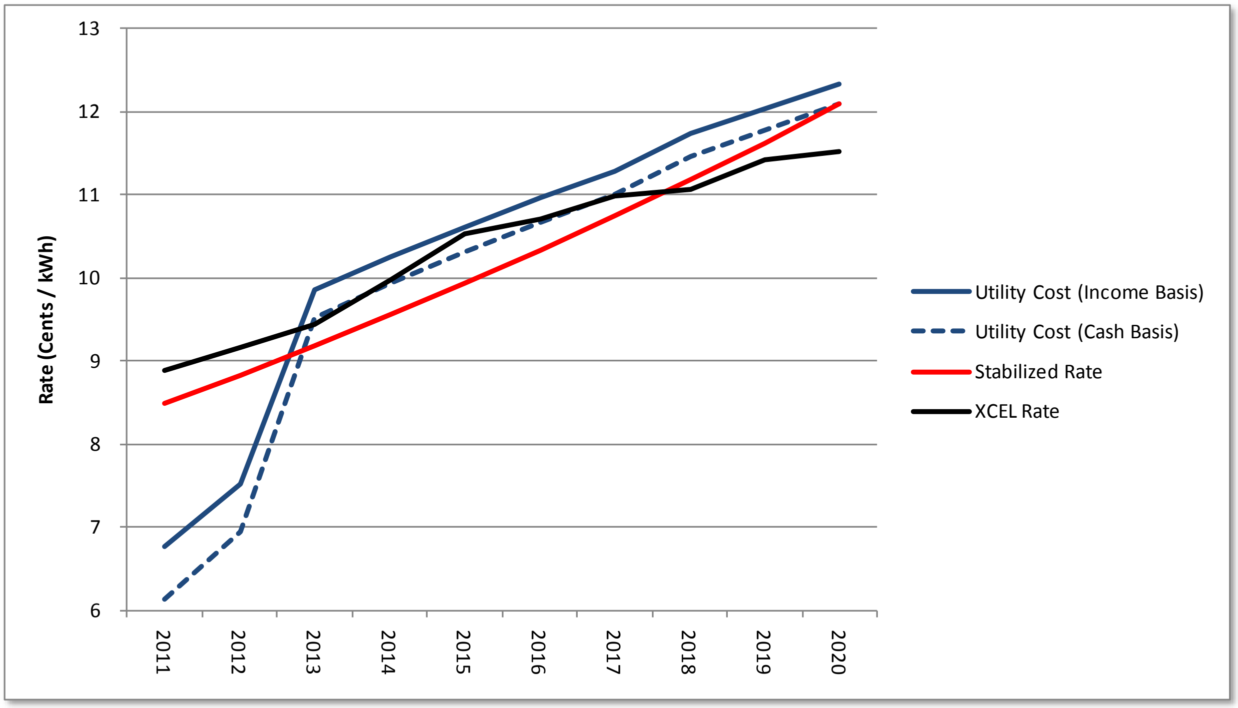


Figure 7: Composite Rates – Max Bond Financing at 8 Percent

Based on the above composite rates and the current allocation shown in Table 2 above, the municipal utility could derive the following retail rates as shown in table 7 below.

COST MODEL STABILIZED COMPOSITE RATES ($/MWh)						
Year	Residential	Commercial	Industrial	Other / SL	City of Boulder	Xcel
2011	115.26	79.87	106.16	250.73	84.93	88.87
2012	119.87	83.07	110.40	260.76	88.32	91.59
2013	124.66	86.39	114.82	271.19	91.86	94.31
2014	129.65	89.84	119.41	282.04	95.53	99.76
2015	134.83	93.44	124.19	293.32	99.35	105.20
2016	140.23	97.17	129.16	305.06	103.33	107.01
2017	145.84	101.06	134.32	317.26	107.46	109.73
2018	151.67	105.10	139.70	329.95	111.76	110.64
2019	157.74	109.31	145.28	343.15	116.23	114.27
2020	164.05	113.68	151.09	356.87	120.88	115.17

Table 7: Retail Composite Rates – Max Bond Financing at 8 Percent

Figures 8 and 9 below illustrate the comparative rates between the composite (accrual basis), stabilized and Xcel's projection for the residential and commercial accounts.

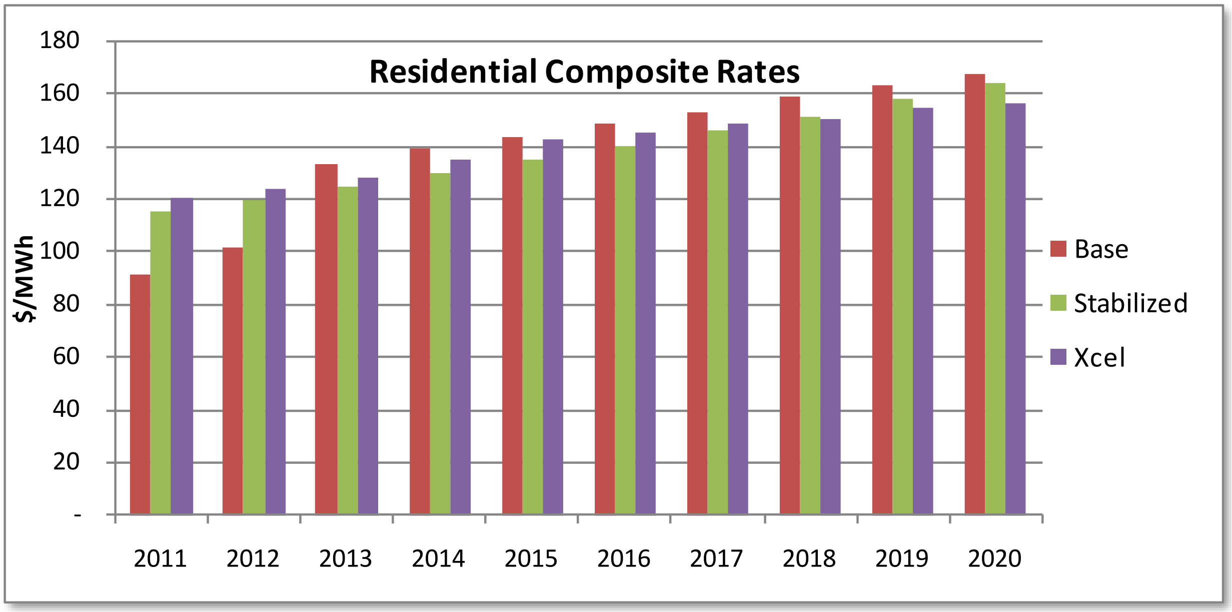


Figure 8: Residential Composite Rates – Max Bond Financing at 8 Percent

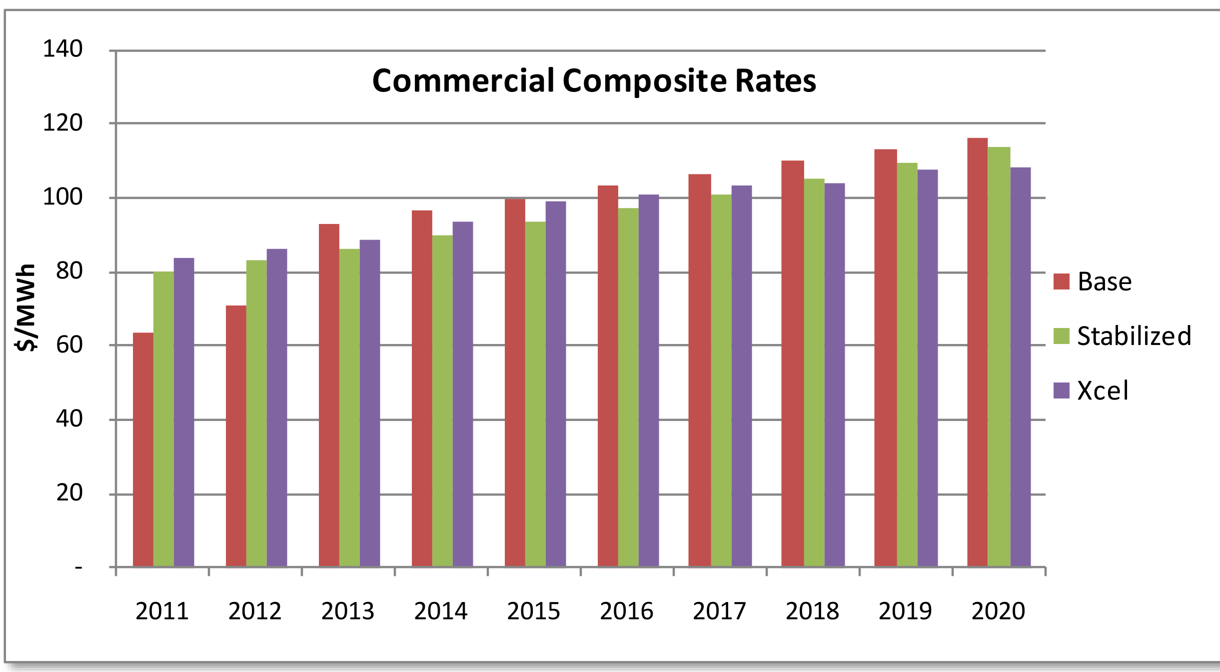


Figure 9: Commercial Composite Rates – Max Bond Financing at 8 Percent

Reducing the Minimum Revenue Margin to $2.5 million

Under the above parameters and reducing the target revenue margin to $2.5 million (from $5 million), an additional $83.2 million in taxable bond financed capital brings the feasibility to a break-even with Xcel's forecasted cumulative revenues over 10 years. Under this scenario, the total project funding would be $306 million. Savings from the municipal utility's annual income (on accrual basis) when compared to Xcel's rate-based revenue yield a 10-year Net Present Value (at a discount of 2.5 percent) of $7.4 million.

Figure 10 below compares the actual and stabilized composite rates to Xcel's projection.

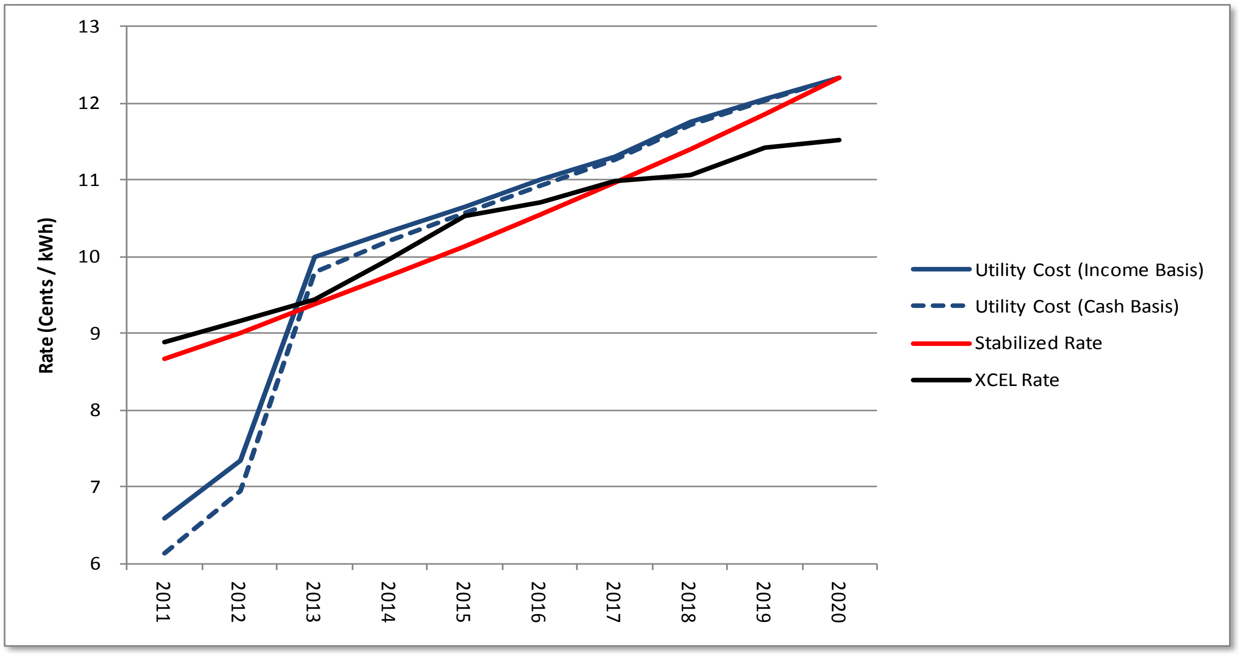


Figure 10: Composite Rates – Max Bond Financing at 8 Percent and Reduced Min. Revenue

Based on the above composite rates and the current allocation shown in Table 2 above, the municipal utility could derive the following retail rates as shown in table 8 below.

COST MODEL STABILIZED COMPOSITE RATES ($/MWh)						
Year	Residential	Commercial	Industrial	Other / SL	City of Boulder	Xcel
2011	117.60	81.49	108.31	255.83	86.65	88.87
2012	122.30	84.75	112.65	266.06	90.12	91.59
2013	127.19	88.14	117.15	276.70	93.72	94.31
2014	132.28	91.67	121.84	287.77	97.47	99.76
2015	137.57	95.34	126.71	299.28	101.37	105.20
2016	143.08	99.15	131.78	311.25	105.42	107.01
2017	148.80	103.12	137.05	323.70	109.64	109.73
2018	154.75	107.24	142.53	336.65	114.03	110.64
2019	160.94	111.53	148.24	350.12	118.59	114.27
2020	167.38	115.99	154.16	364.12	123.33	115.17

Table 8: Retail Composite Rates – Max Bond Financing at 8 Percent And Reduced Min. Revenue

Figures 11 and 12 below illustrate the comparative rates between the composite (accrual basis), stabilized and XCEL's projection for the residential and commercial accounts.

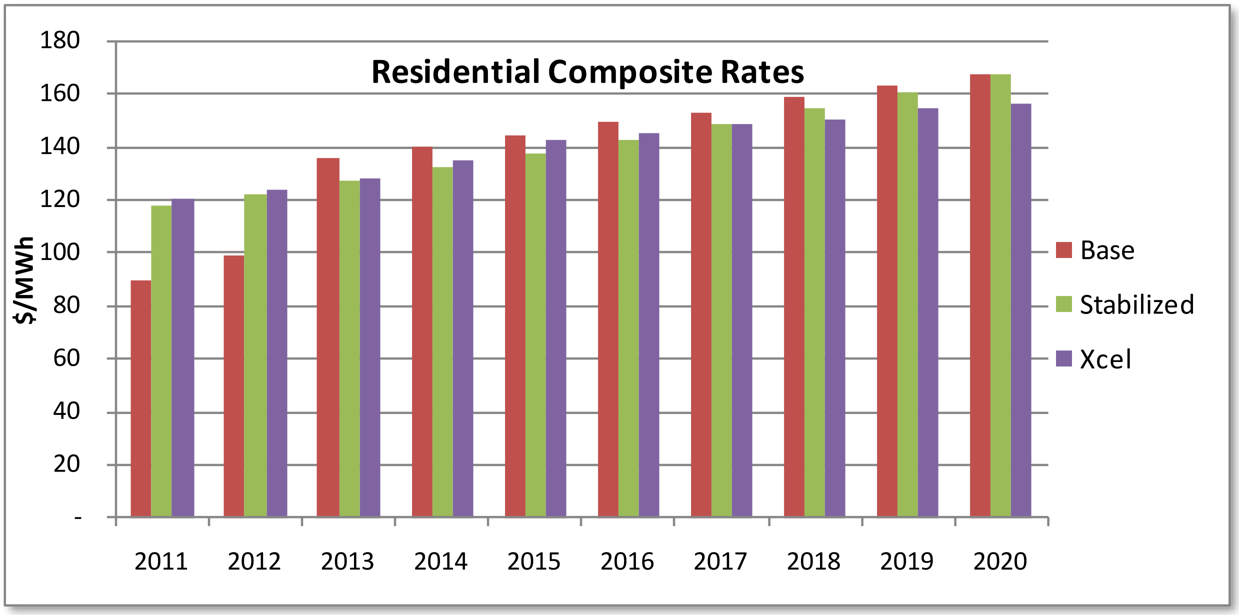


Figure 11: Residential Composite Rates – Max Bond Financing at 8 Percent and Reduced Min. Revenue

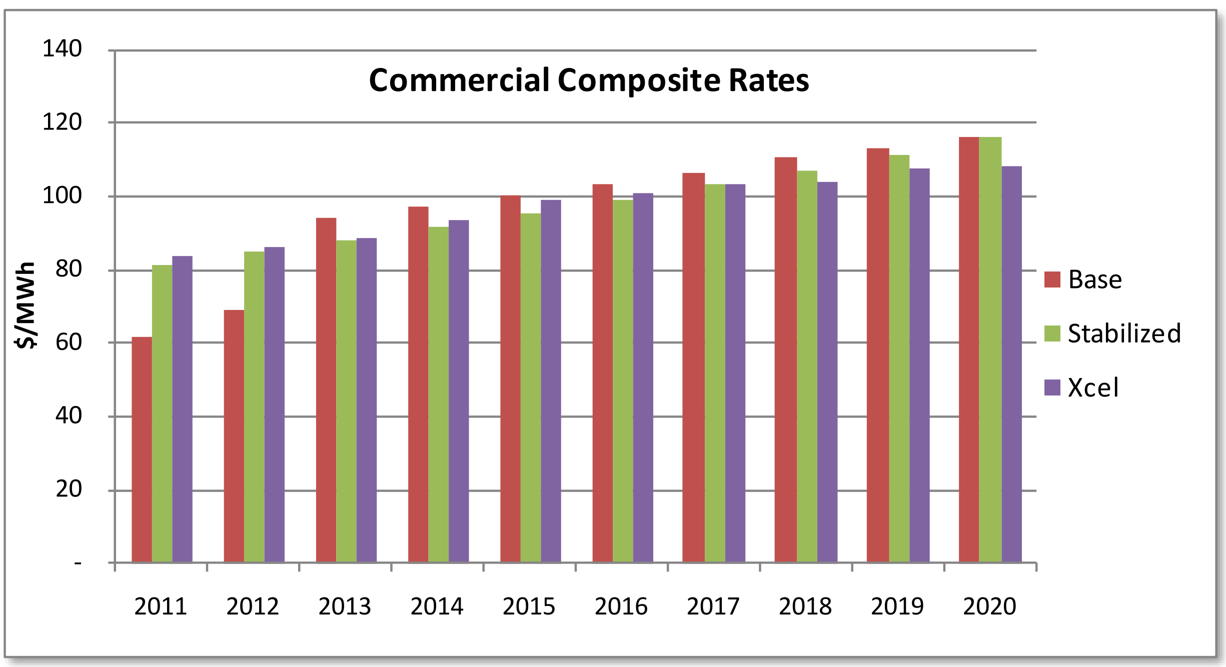


Figure 12: Commercial Composite Rates – Max Bond Financing at 8 Percent and Reduced Min. Revenue

Bond Interest Limits

This section explores the feasibility limits from the bond interest rates in relation to the project funding.

Maximum Taxable Interest for $222.9 Million Project Fund

Under the initial Project funding of $222.9 million, the maximum taxable interest rate would be 9.51 percent, with a non-taxable interest rate of 6.85 percent. Savings from the municipal utility's annual income (on accrual basis) when compared to Xcel's rate-based revenue yield a 10-year Net Present Value (at a discount of 2.5 percent) of $7 million.

Figure 13 below compares the actual and stabilized composite rates to Xcel's projection.

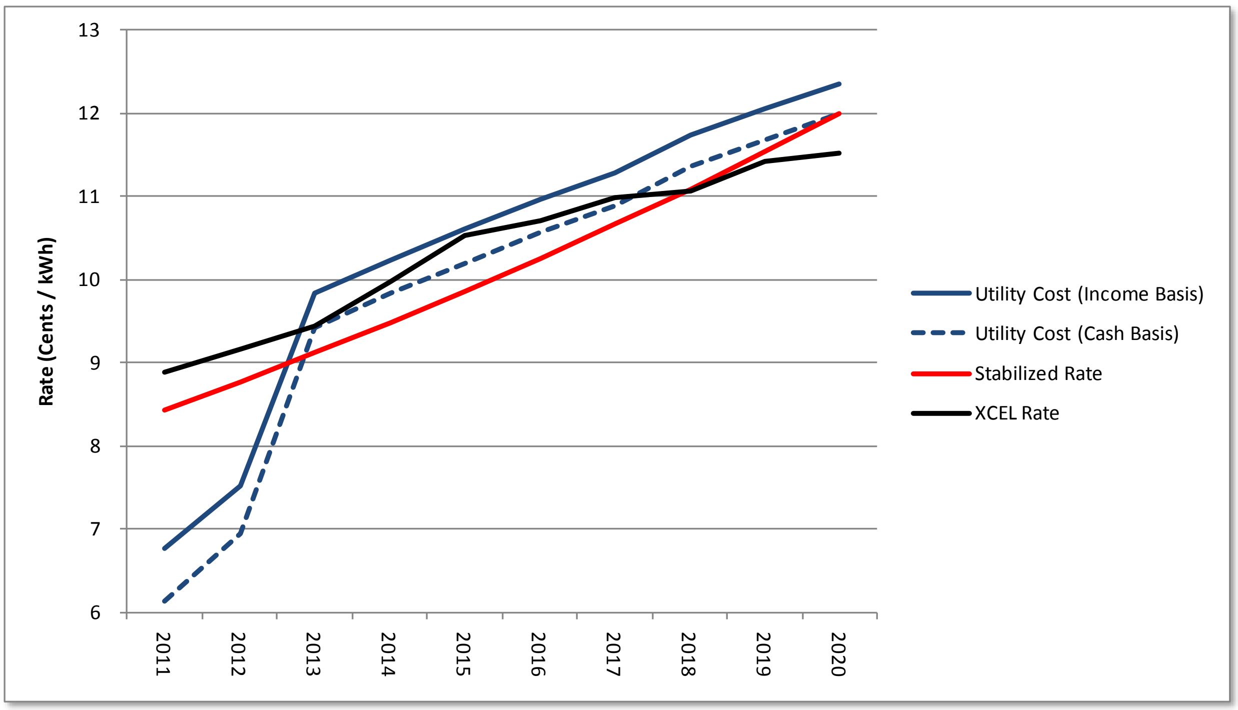


Figure 13: Comparative Composite Rates at 9.51 Percent Taxable Bond

Based on the above composite rates and the current allocation shown in Table 2 above, the municipal utility could derive the following retail rates as shown in table 9 below.

COST MODEL STABILIZED COMPOSITE RATES ($/MWh)						
Year	Residential	Commercial	Industrial	Other / SL	City of Boulder	Xcel
2011	114.32	79.22	105.30	248.71	84.24	88.87
2012	118.90	82.39	109.51	258.65	87.61	91.59
2013	123.65	85.69	113.89	269.00	91.11	94.31
2014	128.60	89.12	118.45	279.76	94.76	99.76
2015	133.74	92.68	123.18	290.95	98.55	105.20
2016	139.09	96.39	128.11	302.59	102.49	107.01
2017	144.66	100.24	133.24	314.69	106.59	109.73
2018	150.44	104.25	138.57	327.28	110.85	110.64
2019	156.46	108.42	144.11	340.37	115.29	114.27
2020	162.72	112.76	149.87	353.99	119.90	115.17

Table 9: Retail Composite Rates at 9.51 Percent Taxable Bond

Figures 14 and 15 below illustrate the comparative rates between the composite (accrual basis), stabilized and XCEL's projection for the residential and commercial accounts.

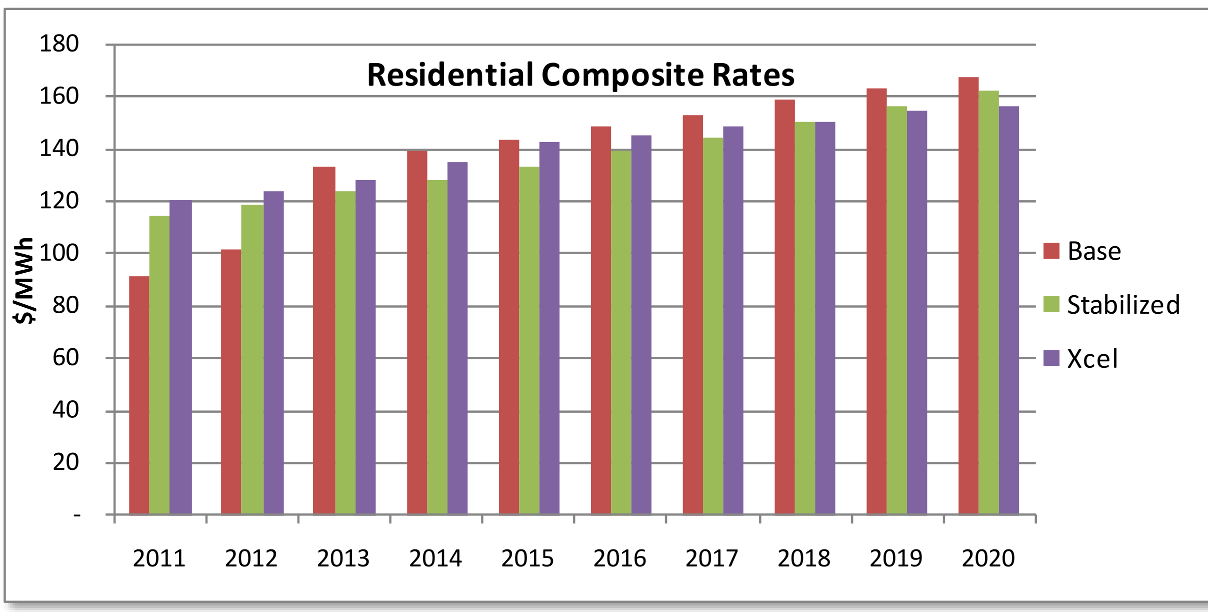


Figure 14: Residential Composite Rates at 9.51 Percent Taxable Bond

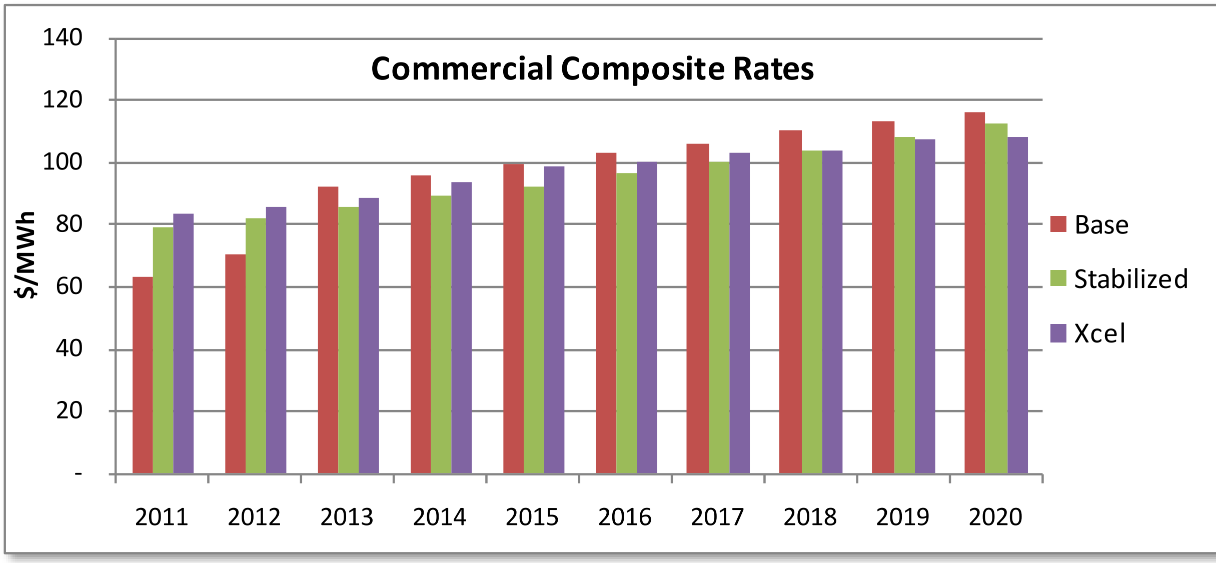


Figure 15: Commercial Composite Rates at 9.51 Percent Taxable Bond

Maximum Funding With 7 percent Taxable Bond

With a 7 percent taxable bond and a 5.04 percent non-taxable bond, the project funding can be increased by $94.8 million to a total of $317.7 million. Savings from the municipal utility's annual income (on accrual basis) when compared to XCEL's rate-based revenue yield a 10-year Net Present Value (at a discount of 2.5 percent) of $6.9 million.

Figure 16 below compares the actual and stabilized composite rates to XCEL's projection.

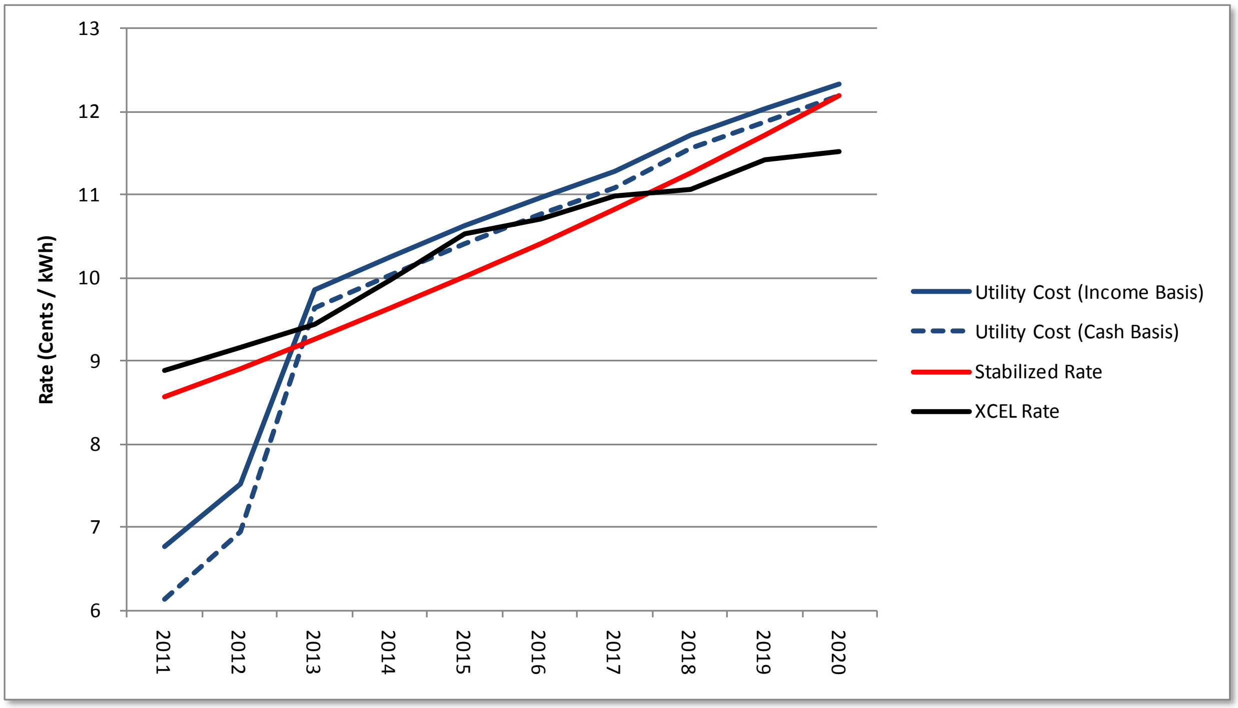


Figure 16: Comparative Composite Rates at 7 Percent Taxable Bond Interest

Based on the above composite rates and the current allocation shown in Table 2 above, the municipal utility could derive the following retail rates as shown in table 10 below.

COST MODEL STABILIZED COMPOSITE RATES ($/MWh)						
Year	Residential	Commercial	Industrial	Other / SL	City of Boulder	Xcel
2011	116.15	80.49	106.98	252.69	85.59	88.87
2012	120.80	83.71	111.26	262.79	89.01	91.59
2013	125.63	87.06	115.71	273.31	92.57	94.31
2014	130.66	90.54	120.34	284.24	96.27	99.76
2015	135.88	94.17	125.16	295.61	100.13	105.20
2016	141.32	97.93	130.16	307.43	104.13	107.01
2017	146.97	101.85	135.37	319.73	108.30	109.73
2018	152.85	105.92	140.78	332.52	112.63	110.64
2019	158.97	110.16	146.42	345.82	117.13	114.27
2020	165.32	114.57	152.27	359.65	121.82	115.17

Table 10: Composite Retail Rates at 7 Percent Taxable Bond Interest

Figures 17 and 18 below illustrate the comparative rates between the composite (accrual basis), stabilized and Xcel's projection for the residential and commercial accounts.

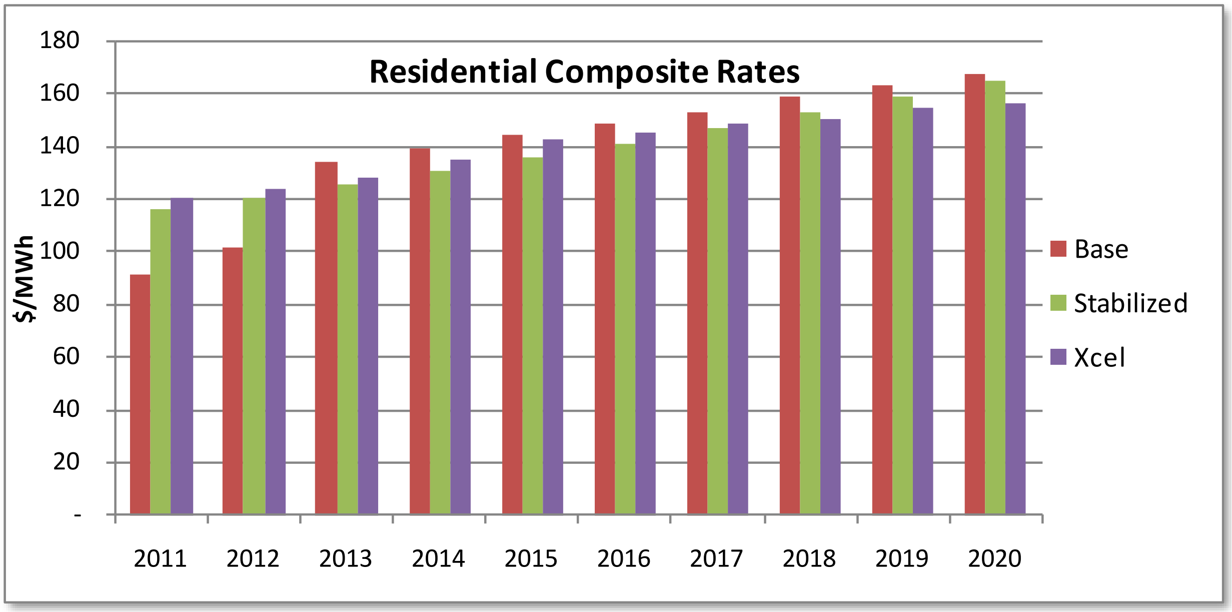


Figure 17: Residential Composite Rates at 7 Percent Taxable Bond Interest

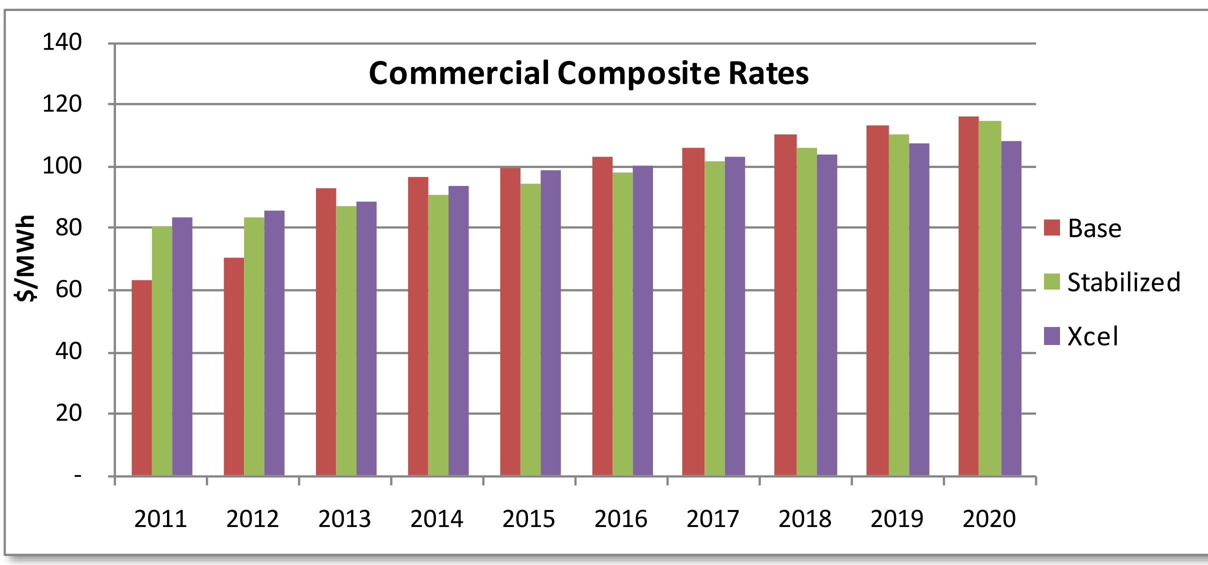


Figure 18: Commercial Composite Rates at 7 Percent Taxable Bond Interest

Additional Scenarios

High Cost Scenario

This scenario is based on increased initial costs (start-up, acquisition, or stranded costs) of $230 million. This additional $230 million is financed by the taxable bond at 8 percent interest rate:

- 10-year Loss NPV compared to Xcel's revenue: $160.5 million
- 10-year average rate parity: 8.9 percent above XCEL's composite rate
- Cash reserve at year 2020: $26.8 million

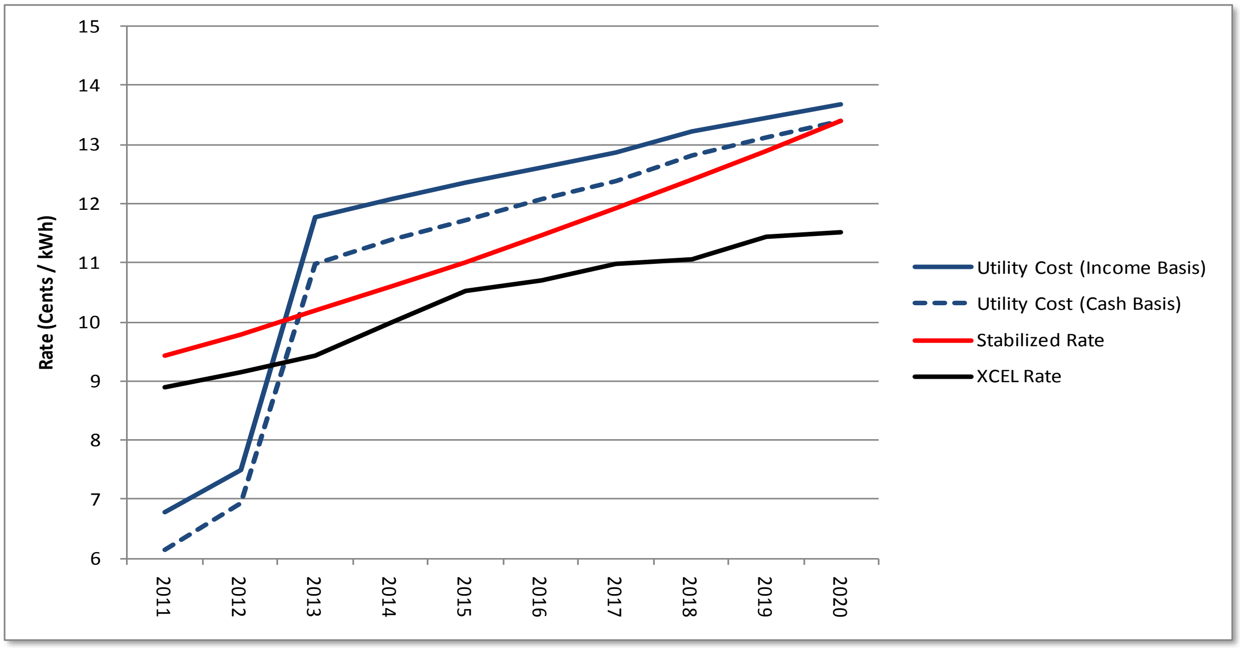


Figure 19: Rate Comparison

COST MODEL STABILIZED COMPOSITE RATES ($/MWh)						
Year	Residential	Commercial	Industrial	Other / SL	City of Boulder	Xcel
2011	127.82	88.58	117.73	278.07	94.18	88.87
2012	132.93	92.12	122.44	289.19	97.95	91.59
2013	138.25	95.81	127.34	300.76	101.87	94.31
2014	143.78	99.64	132.43	312.79	105.94	99.76
2015	149.53	103.62	137.73	325.30	110.18	105.20
2016	155.51	107.77	143.24	338.31	114.59	107.01
2017	161.74	112.08	148.97	351.85	119.17	109.73
2018	168.20	116.56	154.93	365.92	123.94	110.64
2019	174.93	121.23	161.12	380.56	128.90	114.27
2020	181.93	126.07	167.57	395.78	134.05	115.17

Table 11: Composite Rates by Customer Type

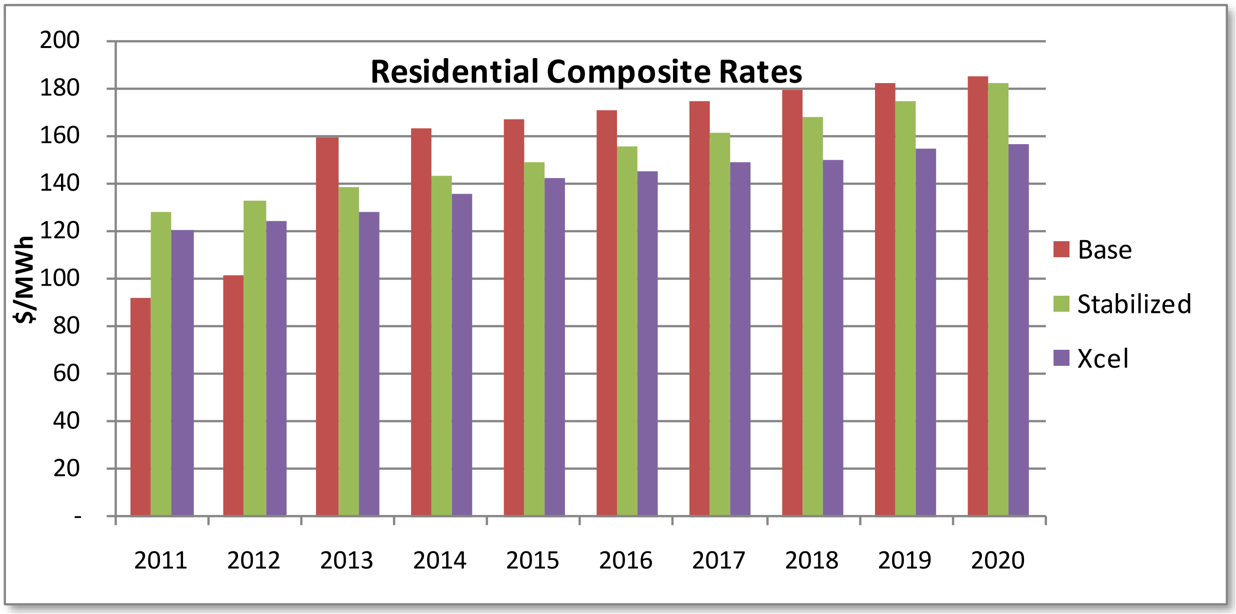


Figure 20: Residential Composite Rate

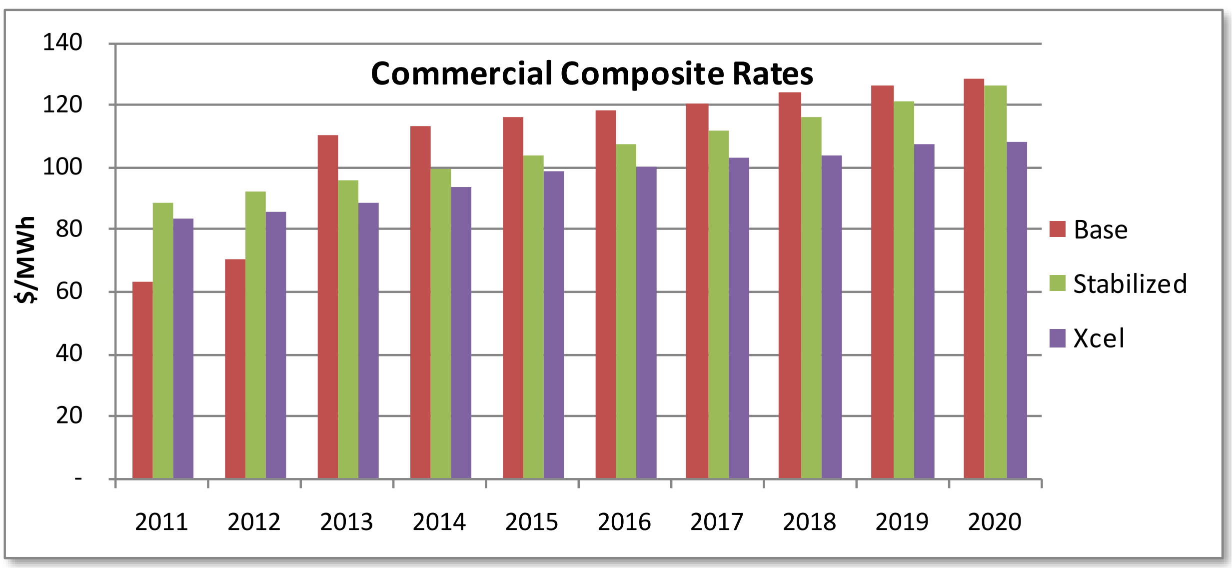


Figure 21: Commercial Composite Rate

Medium Costs Scenario

This scenario is based on additional one-time costs of $134 million. The additional $134 million is financed by the taxable bond at 8 percent interest rate:

- 10-year Loss NPV compared to XCEL's revenue: $53.4 million
- 10-year average rate parity: 3.18 percent above XCEL's composite rate
- Cash reserve at year 2020: $27.7 million

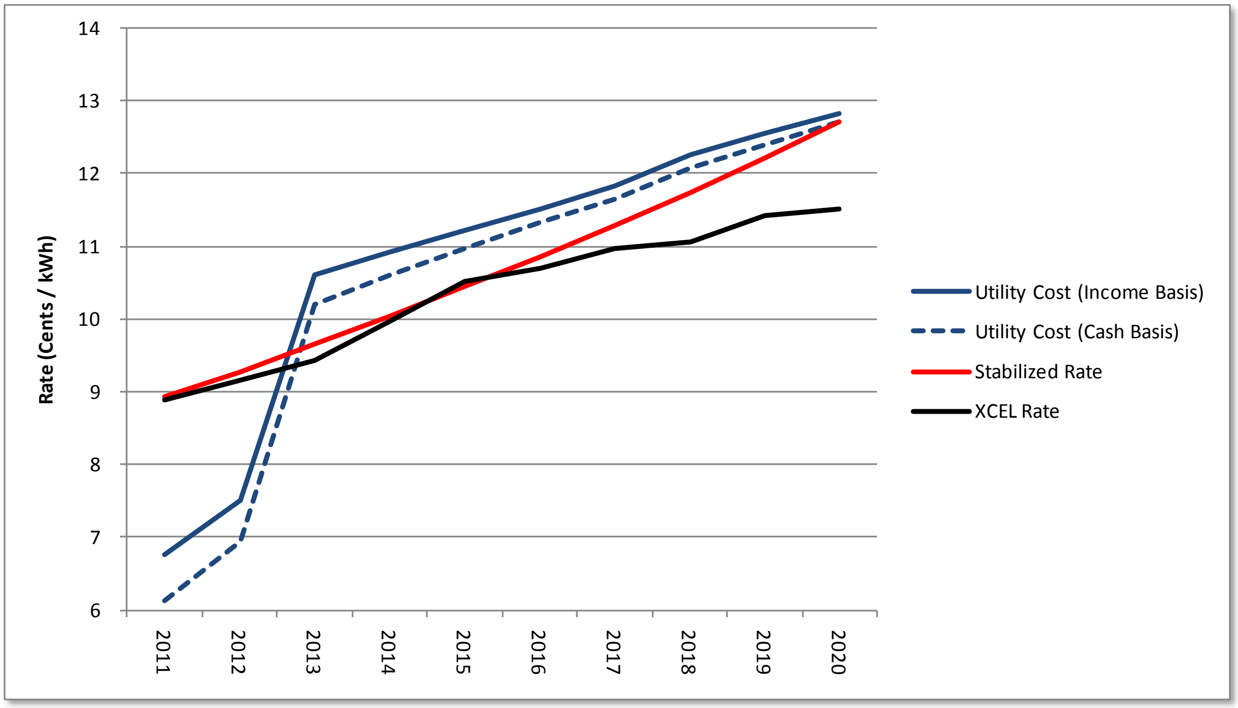


Figure 22: Rate Comparison

COST MODEL STABILIZED COMPOSITE RATES ($/MWh)						
Year	Residential	Commercial	Industrial	Other / SL	City of Boulder	Xcel
2011	121.14	83.94	111.57	263.52	89.26	88.87
2012	125.98	87.30	116.03	274.06	92.83	91.59
2013	131.02	90.79	120.68	285.03	96.54	94.31
2014	136.26	94.43	125.50	296.43	100.40	99.76
2015	141.71	98.20	130.52	308.28	104.42	105.20
2016	147.38	102.13	135.74	320.62	108.60	107.01
2017	153.27	106.22	141.17	333.44	112.94	109.73
2018	159.41	110.47	146.82	346.78	117.46	110.64
2019	165.78	114.88	152.69	360.65	122.16	114.27
2020	172.41	119.48	158.80	375.07	127.04	115.17

Table 12: Composite Rates By Customer Type

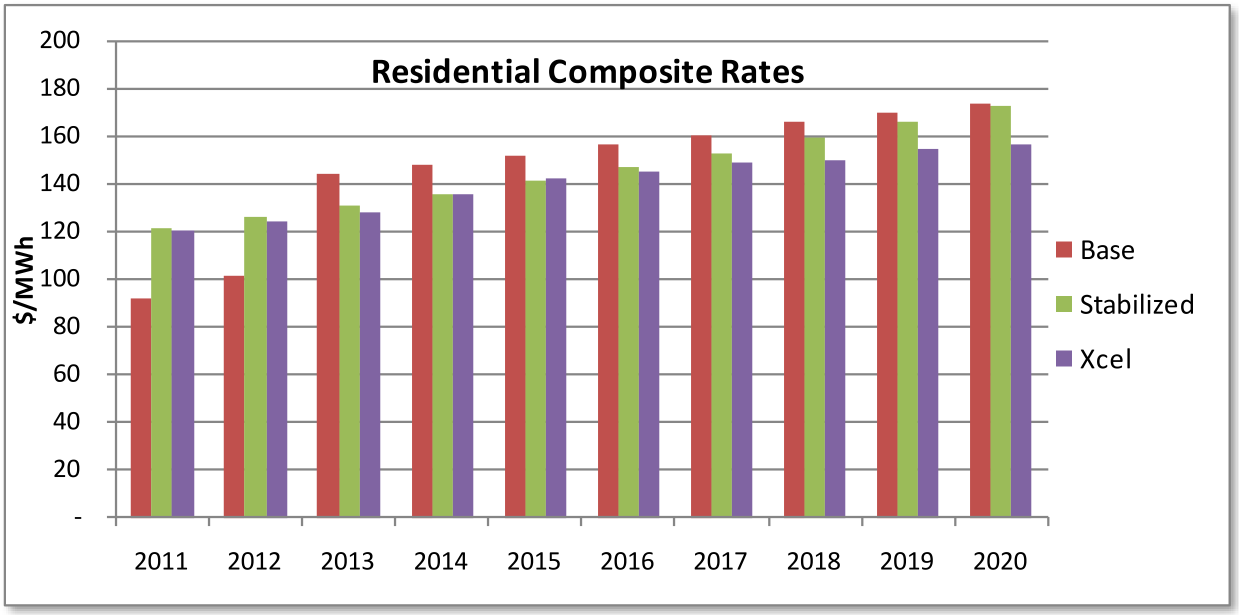


Figure 23: Residential Composite Rates

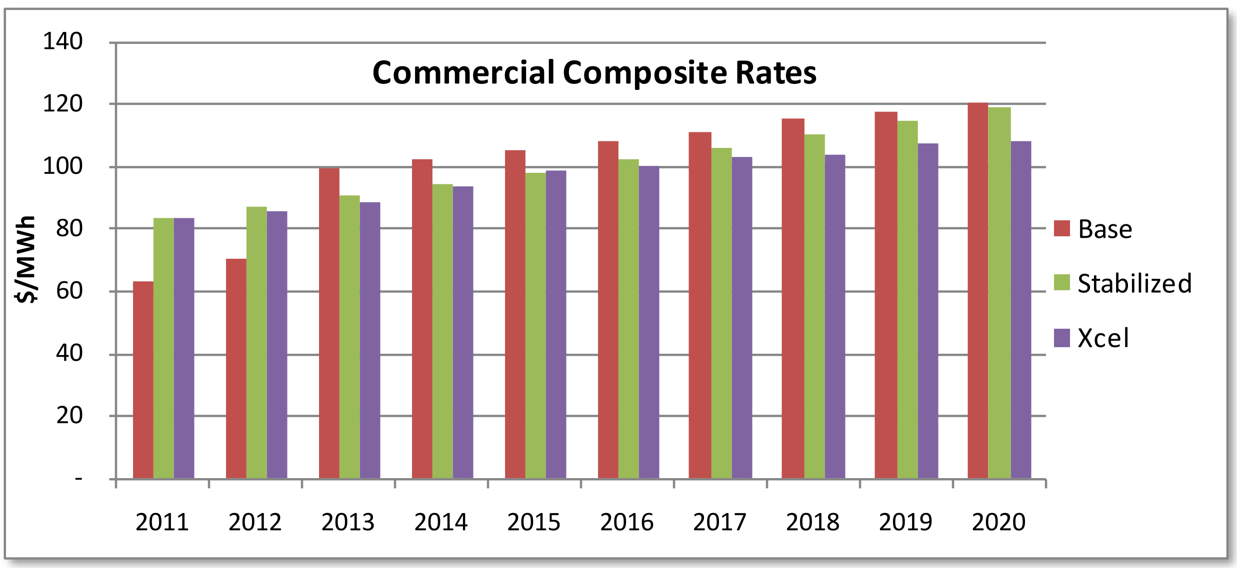


Figure 24: Commercial Composite Rates

Low Costs Scenario

This scenario is based on additional one-time costs of $66 million. The additional $66 million is financed by the taxable bond at 7 percent interest rate:

- 10-year Saving NPV compared to XCEL's revenue: $23.4 million
- 10-year average rate parity: 2.59 percent below XCEL's composite rate
- Cash reserve at year 2020: $28.6 million

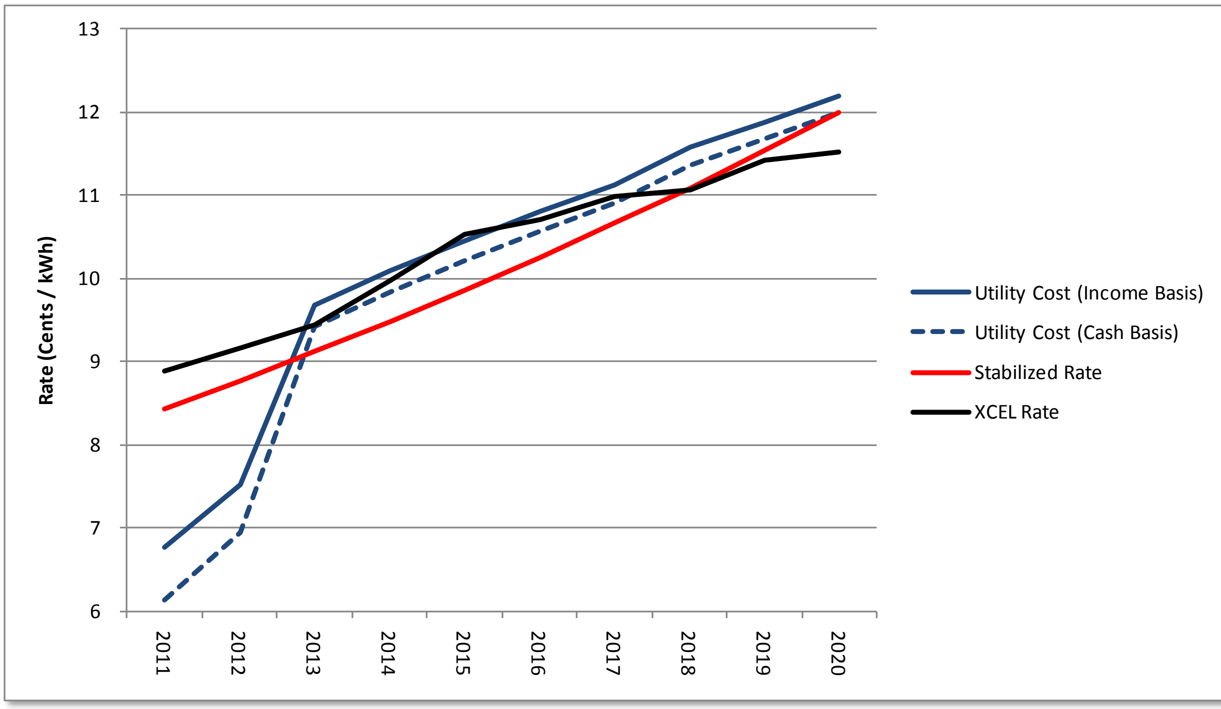


Figure 25: Composite Rates

COST MODEL STABILIZED COMPOSITE RATES ($/MWh)						
Year	Residential	Commercial	Industrial	Other / SL	City of Boulder	Xcel
2011	114.36	79.25	105.33	248.79	84.27	88.87
2012	118.94	82.42	109.55	258.74	87.64	91.59
2013	123.69	85.72	113.93	269.09	91.14	94.31
2014	128.64	89.15	118.49	279.85	94.79	99.76
2015	133.79	92.71	123.22	291.05	98.58	105.20
2016	139.14	96.42	128.15	302.69	102.52	107.01
2017	144.70	100.28	133.28	314.79	106.62	109.73
2018	150.49	104.29	138.61	327.39	110.89	110.64
2019	156.51	108.46	144.16	340.48	115.32	114.27
2020	162.77	112.80	149.92	354.10	119.94	115.17

Table 13: Composite Rates by Customer Type

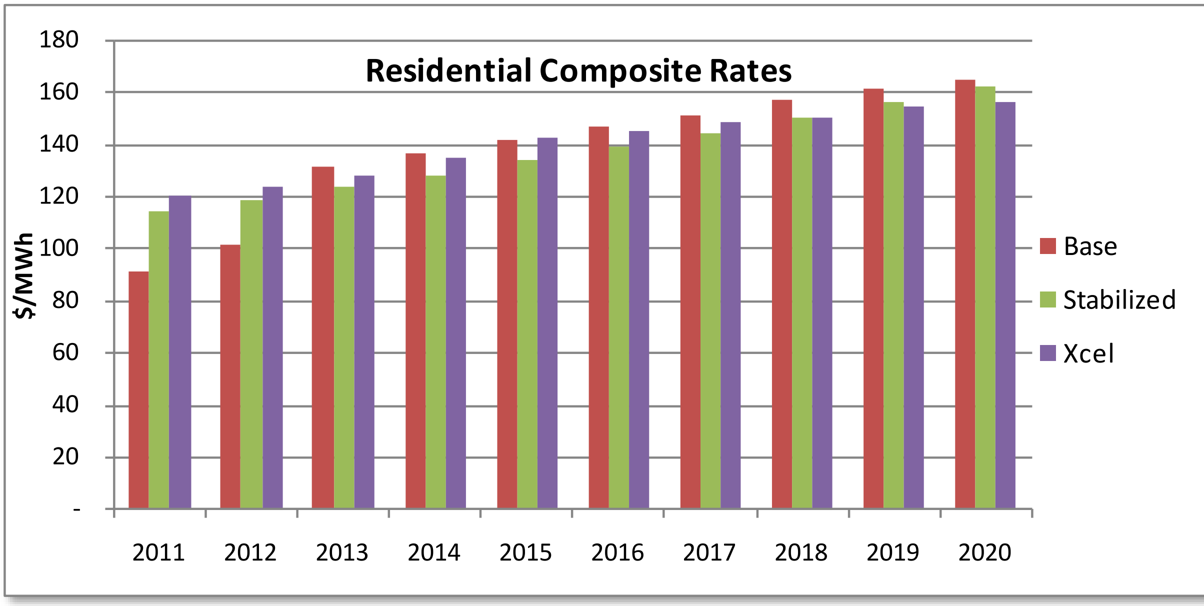


Figure 26: Residential Composite Rates

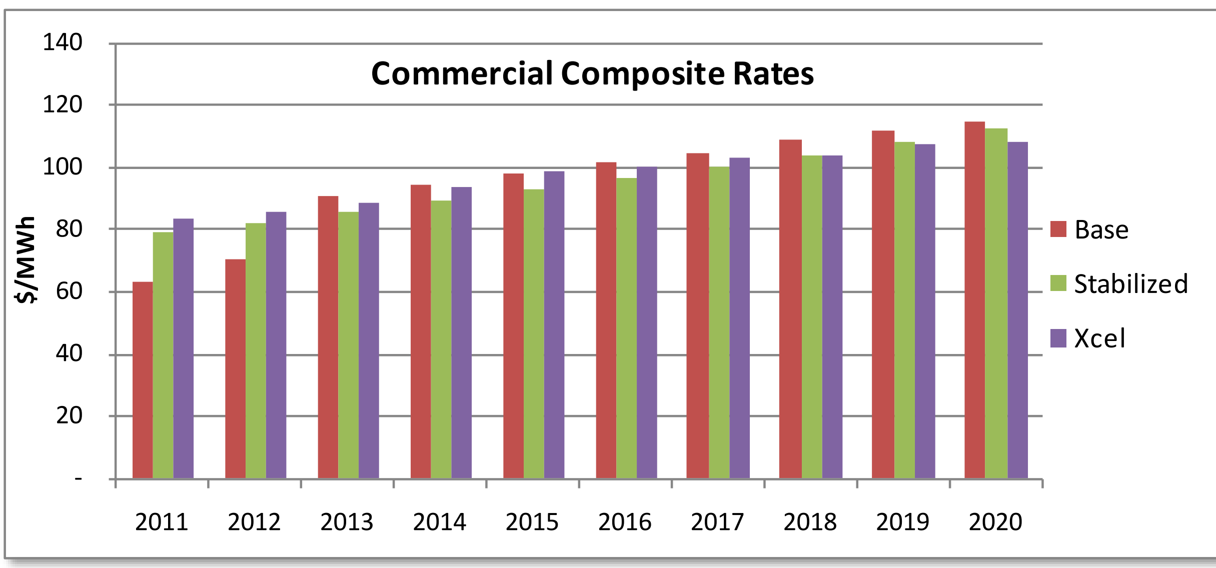


Figure 27: Commercial Composite Rates

Conclusion

This addendum to the feasibility study shows that, under higher PILOT and Public Purpose Program Fund revenues, the municipal utility would compete financially with the incumbent utility, Xcel Energy, under the following factors:

- Similar PV Solar installation growth, entirely funded by operations revenue
- Higher contribution to City, County and School District taxes
- Increased rate stability with a predictable 4 percent annual increase over 10 years
- On average, lower retail rates than the incumbent in all customer sectors

The sensitivity analysis shows that the municipal utility is financially feasible while maintaining rate parity on a 10-year average. The taxable bond rate could increase to 9.51 percent under current parameters. Alternatively the financed capital costs could increase to $272.50 million under an 8 percent rate taxable bond, and to $317.74 million under a taxable bond at 7 percent rate.

Although the stabilized rates seem to exceed the incumbent's in the last 3 years of the study, it is speculative whether the incumbent utility will be able to maintain its composite rates at the projected level after 2017, when it becomes resource-short.

The present sensitivity analysis relies on stabilized rates that are limited to a 4 percent growth rate, and meet the cost-based rate at year 2020. This rate derivation method and the utility's cash reserve in excess of $28 million at year 2020 provide an assurance that the stabilized rates do not need to increase dramatically at year 2021. Based on the municipal utility's capital investment policy, stabilized rates could grow at a lower rate than 4 percent beyond 2020.