BOULDER MUNICIPAL UTILITY

BUSINESS PLAN

Prepared for:

City of Boulder

Prepared by:

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Solutions for Progress

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EXECUTIVE SUMMARY

OPERATIONS

- Pending a positive vote on November 2, 2011, the creation and start-up of the electric utility should take between 18 and 24 months after bond sale.

- Using external resources, such as contractors and other electric utilities, could hasten the start-up of the new utility.

FINANCES

- Bond financing is very expensive. The taxable bond par value is almost 30 percent higher than the financed amount. The city will need to minimize financing as much as possible to ensure a successful, competitive, and robust utility operation.

- The electric utility will likely rely on wholesale market energy during its first 3 to 4 years of operations. The lower supply cost and deferred bond payments will result in initial revenues that can fund:

  - Bond reduction
  - Rate stabilization fund (rate buy down)
  - Acquisition of generation
  - Investment in "localization" infrastructure

- The City should negotiate clauses for early bond reduction and retirement.

- The revenues generated in the utility's initial years can be used in a number of alternative ways, such as acquiring 84 MW of natural gas generation, developing 43 MW of rooftop solar, or acquiring 55 MW of wind generation. An analysis would need to be performed by the utility governing board or technical team to compare the cost-benefit of various scenarios. Upon initial investigation of these alternatives:

  - Wind generation shows the highest cost-benefit, with a reduction in long-term rates comparable to the rate stabilization fund.
  - Solar, under a rebate program, shows good cost benefit and the highest "social" benefit.
  - Natural gas generation shows marginal returns – it might gain value with bio fuels.

- The City may choose to look for alternatives to the $15 million severance of its distribution system, such as servicing customers outside the City or passing through Xcel's billing.

LOCALIZATION

- A municipal utility would establish a local governing board that could make resource investment decisions based on the local load profile and the desires of Boulder customers. As compared to the incumbent utility, if conservation programs were maximized, the local utility could procure less power and offer demand-side management programs without prejudice and regardless of the statewide context.

- Through the Clean Air-Clean Jobs Act, Xcel's Colorado carbon footprint will decrease from over 1,500 lb of CO2 per megawatt-hour (MWh) to 1,200 lb/MWh. By contrast, the local municipal utility can reduce its carbon footprint to 800 lb/MWh.[1]

[1] See 2011 Feasibility Study Report - RBI

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1 Objective

The City of Boulder is considering the creation of an electrical municipal utility to serve its community according to its core values. The city's objectives align with the following four key components

- Rate stability
- Service reliability
- Reduction of carbon emissions
- Local control of energy decisions and maximum investments in local power

Boulder's core values are reflected in many years of policies that have shaped the community:

- Growth limitation, as outlined in the Danish Plan and supported by the first tax-funded Open Space program in the nation;
- Environmental stewardship, with a particular concern for carbon emissions and climate change (including the first self-imposed climate action tax in the nation)
- Social equity as reflected in Boulder's robust human services and aggressive city-sponsored affordable housing programs;
- Economic vitality, fostering advanced technology businesses and national laboratories

2 Goals

The Business Plan states the following goals to realize fully the objectives:

- Create a local municipal electric utility with cost-based rates tailored to its customers.
- Achieve economies of scale with regard to operating expenses and public purpose incentive programs.
- Improve short- and long-term reliability of service with upgrades to the distribution system, access to alternative transmission, access to alternative energy supplies and acquisition of local generation.
- Reduce dependency on fossil fuel generation through an increased renewable resource portfolio, distributed generation, demand-side management, energy storage and other advanced technology solutions.
- Create a local municipal utility that will be available and responsive to its customers.

3 Structure of the Utility

The electric utility would be formed as a municipal utility that reports to the City Council.

City Council could have approval authority of the utility budget, rates, bonds, and policies.

The utility would likely be directed by a Board comprised of City Council members, utility experts and stakeholders. The Board would designate a General Manager (GM) to run the utility operations in conformance with the City Council vision and the Board's strategic directions. The GM would have an indirect report to the City Manager. The Board would also designate a Trustee and a legal counsel. Both would assist the GM and report to the Board. The Board would also have supervision over a Technical Committee that would assist the GM with the investigation, feasibility and planning for new technologies, renewable resources, rebate programs and demand-side management.

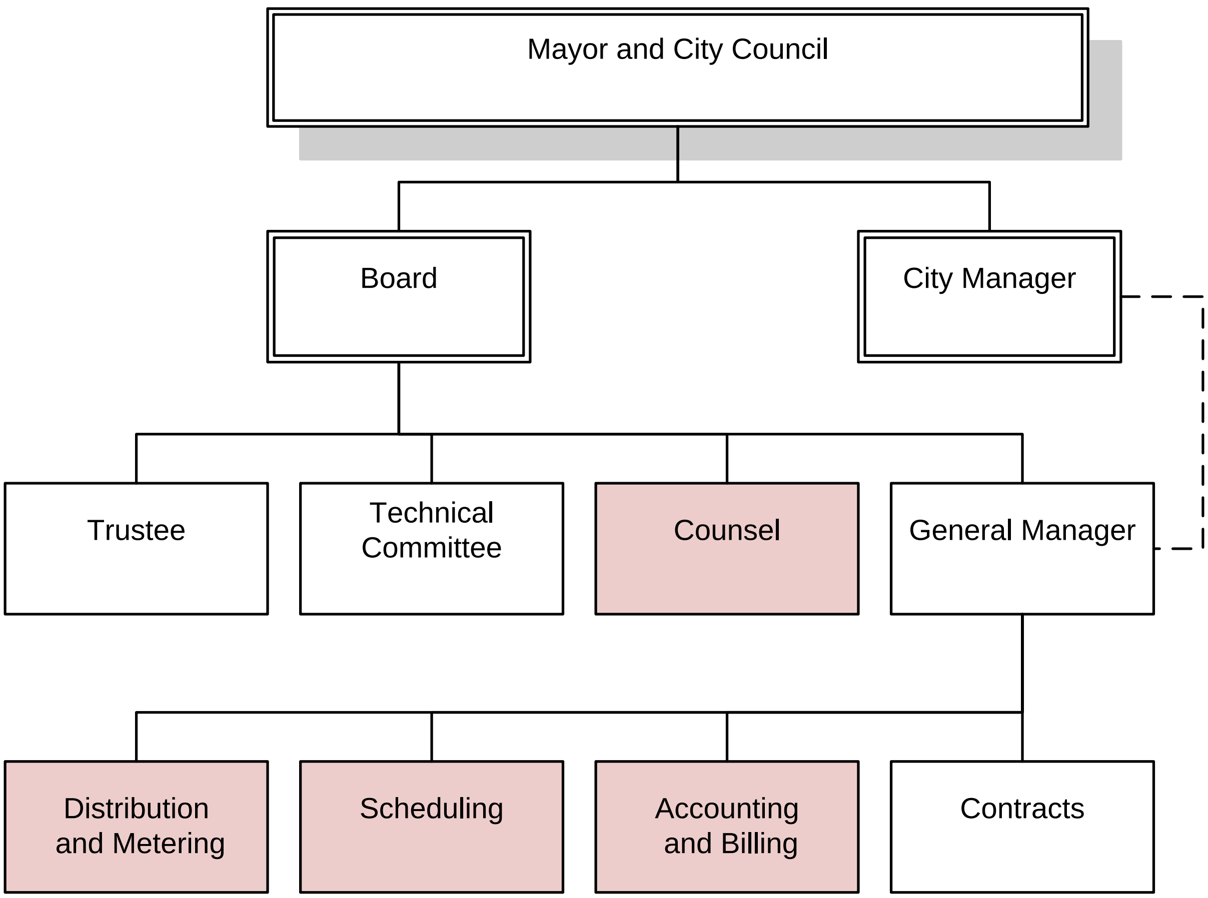

Figure 1: Utility Structure (The shaded services can be started by third-party contractors)

The utility would have four departments reporting to the GM:

- Distribution and Metering
- Load and Resource Scheduling
- Accounting and Billing
- Contract Management

The municipal utility would be created as a Load Serving Entity (LSE). The LSE may elect to become a transmission utility in the future.

4 Operations Information Flow

The following diagram illustrates the intricacies of operational information flow, much of which can be automated.

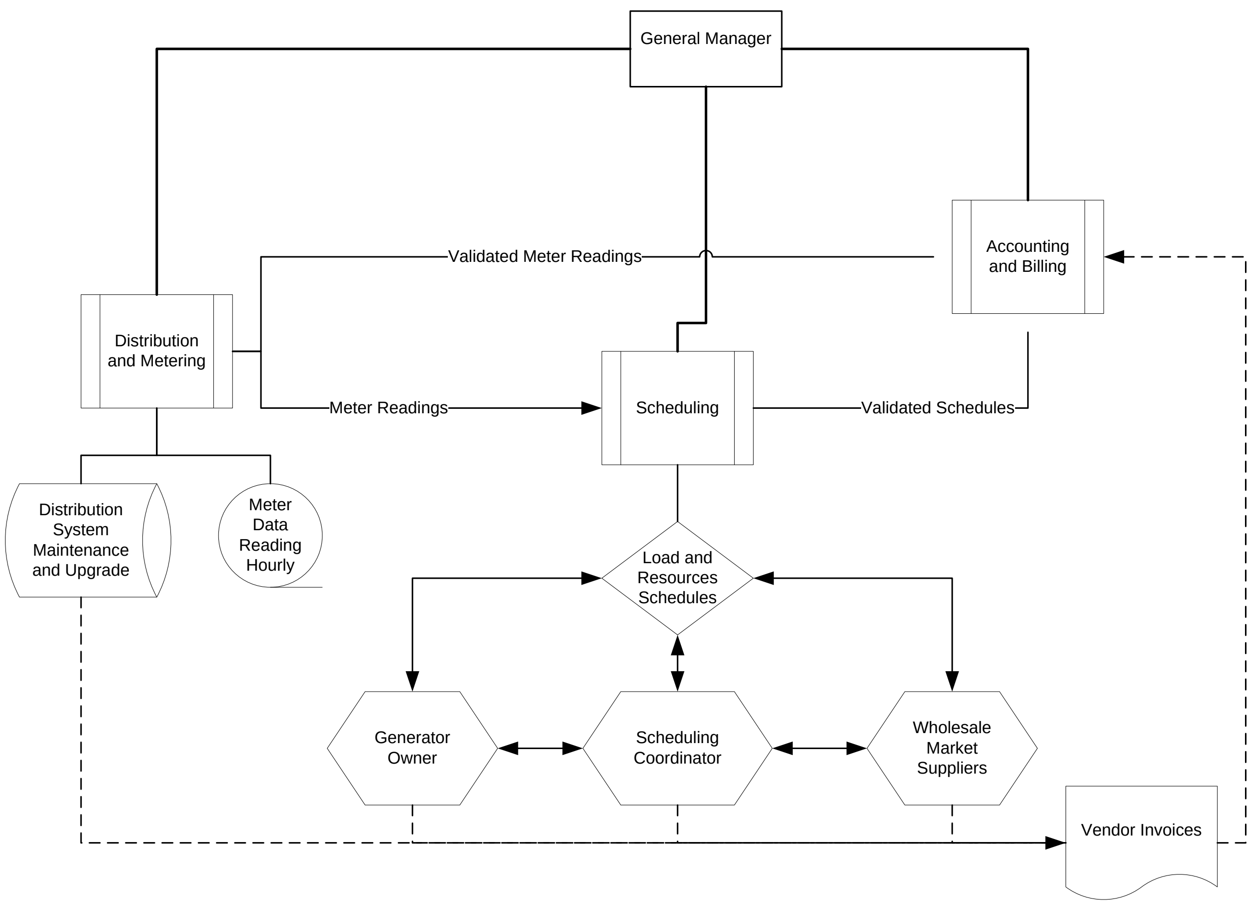

Figure 2: Information Flow

The **Distribution and Metering Department** ensures the functioning and upgrade of the distribution system, from the substations to the customers meters. It continuously feeds meter readings from the substations to the Scheduling Department. It verifies, validates and estimates (VEE) the customer meter readings and sends the detail to the Accounting and Billing Department once a month.

The **Scheduling Department** forecasts the load and generation resources, and adjusts the forecasts with incoming meter data. The department sends the load and resource schedules to the Scheduling Coordinator (SC), to the generation operators and market vendors on the day-ahead market. As meter data keeps flowing in, the department makes real-time adjustments when necessary. It sends the validated schedules to the Accounting and Billing Department daily or weekly.

The **Accounting and Billing Department** generates the customer billing from the VEE meter readings and receives payments. It receives vendor invoices, which it validates against Power Purchase Agreements, schedules, contracts and work orders. The Accounting and Billing Department handles payments up to a specified clearance, beyond which payments are handled by the Trustee or the Board. Finally, the department prepares cost and revenue forecasts, budget and rates under the direction of the GM.

The **Contract Department** (not shown) initiates the Requests for Proposals, issues the Power Purchase Agreements and vendor contracts. This department also resolves any contractual issues.

All four departments report to the GM, who provides coordination and review of performances. The GM also provides guidance to departments based on instructions received from the Board. Finally, the GM reports to the Board the results from operations, the budget, rates and cash flows.

The majority of the operational information, such as meter readings, load forecast, scheduling, schedule validation, billing and invoice validation can be handled from a computerized database. The database offers a central repository with instant access to all data, and the ability to analyze trends across all inputs. Additional input to the database would include weather forecast, commodity prices, generator operations, and network capacity constraints.

5 Estimated Benefits

Based on the city's objectives of:

- rate stability,
- service reliability,
- reduction of carbon emissions, and
- local control of energy decisions and maximum investments in local power,

a local municipal utility could realize benefits as measured against the incumbent utility.

5.1 City's Goals

Rate Stability

Local utility: The municipal utility has many options to secure near and long term rate stability:

- By developing a risk policy and prudently procuring energy futures to hedge the forecasted net short position against the volatility of peak electricity prices.
- By capitalizing on the seasonality of commodity prices such as off-peak wholesale electrical energy and summer natural gas prices.
- By creating a rate stabilization fund (rate buy down) to control sharp rate increases over a period of time, and provide near and midterm price certainty to its customers.
- By developing and owning capacity reserve such as natural gas generation and utility-scale storage, for example pumped storage.
- By developing and owning utility-scale renewable generation. For example, a wind development policy funded by net revenues rather than financing, could secure upward of 55 MW of generation over 10 years and reduce wholesale market purchases by 6 percent. Similarly, geothermal and biomass present great opportunities for baseload resources.
- By scheduling resources at their most economical advantage. Dispatchable resources include hydropower and natural gas generation. For example, the value of a MWh of hydropower is much higher when it displaces expensive on-peak energy purchases than when it competes against low-cost off-peak market.
- By fostering new technological implementations such as energy storage, thermal solar with non-evaporative cooling, reduction of intermittency in PV Solar and wind generation, synergies between loads and energy sources resulting in cost peak-shaving.

Incumbent utility: Xcel limits its customers' options to its portfolio of resources and general corporate policies on generation ownership. Rates are vetted through a PUC process and any approved rate increases are based on Xcel's resource decisions in a statewide context regardless of Boulder's priorities.

Service Reliability

Local utility: The utility could strike alliances with neighbor municipal and publicly owned utilities for emergency response, portions of the distribution operations, management of capital spares, access to other transmission networks, and generation resource pooling.

In addition, the city will be able to upgrade its distribution system according to its own policies such as:

- Accelerating the line undergrounding.
- Developing new standards for undergrounding, for example combining power line conduits with compressed air piping and central heat, and capitalize on the initial cost of trenching.
- Upgrading meters and distribution transformers to facilitate future efforts for SCADA (Supervisory Control and Data Acquisition) and vehicle charging.
- Surveying the existing distribution system and making proactive corrections on non-conforming installations.
- Building redundancy of service for commercial and industrial customers by means of distributed generation, co-generation and energy storage. Improving voltage and frequency control at customer sites.
- Improving the reactive load to minimize energy losses.

Incumbent utility: Although the incumbent utility, Xcel, has provided reliable service to its Boulder customers, it provides a uniform maintenance policy, which may not be as proactive or customer-oriented as a local utility's.

Carbon Reduction

The incumbent utility has been a leader in wind development over the past 20 years and its renewable portfolio complies with the State Renewable Portfolio Standard (RPS); yet even under the Clean Air-Clean Jobs Act resource shifts, its carbon footprint will only decrease from 1,500+ lb to 1,200 lb of CO_2 per MWh. By contrast, the City can reduce its carbon footprint to 800 lb per MWh by purchasing wind resources that are firmed with natural gas.[2]

Local Control, Local Resources

Incumbent utility: Xcel is an investor-owned utility governed by the rules and regulations of the Colorado Public Utilities Commission (PUC). The decisions Xcel makes relating to resource acquisition, demand-side management and rates must be applicable to its entire service territory, regardless of regional differences in load profile, conservation efforts or local building code efficiency requirements. It is difficult for a Boulder customer to have an influential voice at the PUC alongside other statewide interests.

Local utility: In contrast, a local municipal utility could offer rebates and conservation services as well as power supply resources that match its local demand and the desires of the community it serves. Preference could be given to local businesses that can provide energy management solutions to its customers and the local utility board can take other community priorities into consideration.

[2] See 2011 Business Plan addendum Report - RBI

5.2 Financial Benefits

Incumbent utility: Xcel allocates its transmission and distribution costs for its entire service territory to all its rate payers in proportion to energy billings. In reality, much of these costs are subject to complications for transmission and distribution such as: long distances, irregular and rocky terrain, low population, difficult vegetation, etc. Little of this applies to Boulder; therefore, it is likely that the Boulder customers pay more than their share for transmission and distribution infrastructure and services. Conversely, much of the incentive programs under Renewable Energy Standard Adjustment (RESA) are funded by the Xcel's customers statewide, whether or not they participate in the programs; for example, SolarRewards rebates are funded in part by rate payers outside of Boulder, who do not benefit from the REC purchases. Likewise, WindSource rate payers do not get the benefit of the extra wind RECs sold by the incumbent utility outside of Colorado.

Additionally, rate payers finance the acquisition of Xcel's infrastructure such as transmission lines, distribution systems, power plants including wind generation, without ever owning the assets; this would be comparable to a lifetime rent without an option to purchase.

Local utility: The local municipal utility, on the other hand, could create new employment and retain a larger portion of the cash flow within the city. At the minimum, the city would retain approximately $24 million annually (in 2011 dollars):

- Municipal utility operations: $ 11.5 million
- Public Purpose Fund: $ 4 million
- Payment In Lieu of Taxes: $ 3.5 million
- Utility net income: $ 5 million

5.3 Information Transparency

The incumbent utility serves a large territory and cannot practically focus on Boulder's needs and desires. A municipal utility would enable the city to access its energy data and devise, implement and monitor progressive solutions that meet its core objectives. Furthermore, the utility board could choose to pull from local technological resources to implement many of its programs.

5.4 Accountability

As stated above, under section 5.1: Local Control, Local Resources, a Boulder customer of Xcel has very little say over its policies and programs. For example, under similar scenarios as the 2001 rolling blackouts in California[3] or the 2003 Northeast blackout, rate payers would have little no recourse.

A local municipal utility would be held accountable at all levels on the operation performance and transparency of information. Boulder customers would have more influence in the general energy policies and planning of the utility.

6 Utility Creation

6.1 Planning

The planning starts at the November 2011 elections if the city seeks voters' authorization to create an electric utility, amend the City charters for utility governance and issue revenue bonds. This initial step gives the City the clearance to proceed with the 4 planning phases, each with an off-ramp, prior to actually creating the utility and issuing bonds. In addition, the vote creates a legal obligation, both at the State and at the Federal regulatory levels, for the incumbent utility to release detailed information to the City; such information includes access to the substations, detail of the distribution assets inventory, detailed drawings and historical meter data.

The first phase of the utility planning entails updating the models and feasibility study as the City staff accesses detailed information from the incumbent utility and finalizes the distribution asset valuation, the severance plan and other key parameters necessary for the negotiations and resource planning. The cost model will be updated accordingly and, based on the results; City council will decide whether to continue the effort. As soon as the distribution assets inventory and valuation are completed and the severance plan is developed, the phase 2 starts, which consists in negotiating the acquisition of the distribution assets and stranded costs with the incumbent utility. Phase 2 leads to three options:

- Bonding and creation of the utility if negotiations are successful
- Litigation under State and Federal ruling, with a possible off ramp
- An off ramp and decision to return to a franchise agreement

Given the successful acquisition of assets and stranded cost settlement, the last planning phase consists of:

[3] Interestingly, rolling black-outs affected mostly customers served by the IOUs. Several municipal utilities were not affected at all.

- Final update of the models
- Bond sale
- Development of the utility board governing policies
- Creation of the utility

The planning phases are expected to take between 2 and 5 years.

6.2 Creation of the Municipal Utility

The municipal utility is created first as an administrative entity and, later as a functioning entity. The first step entails financing the legal and engineering efforts.

A FERC[4] filing is initiated to create a Load Serving Entity as a wholesale customer of Xcel under the Open Access Transmission Tariff (OATT).

In parallel, the utility starts hiring contractors and staff, and deploys its operations infrastructure.

6.3 Resource Procurement

The utility should promptly secure Power Purchase Agreements (PPAs) with wholesale market vendors to ensure a portfolio of firm resources. The initial contract is a Master EEI[5] Agreement. Additional agreements should include a Day-Ahead Market, a Real Time Market and an Odd-Lot Confirm. Market vendor may be able to provide a renewable mix with their contracts; however, the generators are typically non-designated, meaning that the city would receive grid energy and Renewable Energy Certificates (RECs).

Wholesale market contracts take less than three weeks to set up. They provide the necessary protection against load imbalance. With the market PPAs secured, the utility can commence operations.

The next set of PPAs is for local generation, renewable and firming resources. The Board and the GM should be mindful of the following:

- New generation can take up to 5 years from planning through permitting to start-up.
- It may be in the city's interest to own generation assets rather than issue a 20+ year PPA. There are different strategies to lease-to-own assets with financial benefits. These strategies should be reviewed on a case-by-case with the developers.

[4] Federal Energy Regulatory Commission
[5] Edison Electric Institute

- Firming and capacity generation PPAs should not exceed 3 years, renewable. The generator should guaranty output, ramping capability, and heat rate.
- Generators with a heat rate above 9,000 BTU / kWh should not be contracted for firming.
- PPAs should include a clause that enables the utility to compete with its own generators, as well as exit clauses.
- The Board should consider electric energy PPAs as well as heat rate contracts.

The utility should make its first trade two days before commencing operations, otherwise it would be entirely exposed to costly imbalance for 48 hours.

6.4 Utility Start-up

Taken together with the city's Draft Utility Development Plan, the following sections provide a general outline of the steps necessary to start a new electric utility. There are many variables and some tasks may be taken on in a different order than is described here. If voters approve creation of the local utility, a transition and operating plan will need to be developed with specific and detailed guidance and work plans to govern the utility start-up.

There is no deadline to start the utility, other than financial and political pressure. The City will first coordinate a start date with the incumbent utility for the municipal utility as a wholesale customer; meanwhile the incumbent will continue to serve its ratepayers as retail customers.

A bonding effort will be necessary to fund the utility start-up. The bond financing affords the utility enough credit-worthiness to issue contracts for Open Access (transmission and ancillary services) and wholesale resources. The bond amount is estimated at $287 million to facilitate a $223 million start-up financing. The City should negotiate the possibility to repay the taxable bond, or parts of it, early in order to have the option to reduce the debt service. Bond financing parameters are detailed in Appendix B.

6.4.1 City Staff

The utility would need to hire a General Manager (GM) to orchestrate the start-up.

The city has departments and existing utilities that may provide experience and resources for contracting, billing and meter reading. Further analysis is needed to assess overall staffing needs and the feasibility of sharing existing positions.

6.4.2 Distribution Operation

Next, the nascent utility could issue a Request for Proposal (RFP) for the survey and documentation of the distribution system, as well as possible operation and maintenance. If the distribution contractor is being utilized for operation and maintenance, it should provide specific levels of staff and equipment, insurance and performance bonding. The contractor should also have a training and safety program. The distribution contract should have the following clauses:

- Allow the city to hire another contractor (no monopoly of service)
- Limit contract term to 3 years, renewable annually.
- Set performance criteria for safety, regulatory compliance, system availability and reliability, meter data accuracy, completeness and availability.
- Request a training and safety program that City staff can attend.
- Request monthly operations report and meeting attendance.
- Indicate the City's desire to take over distribution operations.

At a minimum, the contractor should complete a detailed inspection and assessment of the distribution system to uncover any safety issues or other operational deficiencies, especially after a period of time wherein the incumbent utility had known the system was being purchased and may have deferred maintenance of system components.

6.4.3 Metering Database

During the system survey period, the contractor and the utility should develop a strategy for the metering database. The contractor is likely to make recommendations; however, the GM should be careful not to commit the utility to built-in incompatibilities or proprietary issues that would prevent the utility from letting go of the contractor.

The database should remain the property of the city, although the software might be licensed from a third party. There are several commercial packages available, including from the meter manufacturers. The metering database and software specifications should include the following capabilities as a minimum:

- Local server, with remote Demand Response server and back-up
- Fast technical support
- Easy interface with other databases
- Ease of configuration
- Data security
- Reporting capabilities with other common office software
- Expandability
- Speed of operation

The municipal utility should contact other utilities to discuss merits and pitfalls of common software packages.

6.4.4 Scheduling Agent

The City should issue an RFP for a scheduling agent to perform the following tasks:

- Load and resource modeling
- Day-ahead schedule preparation, compatible with the Scheduling Coordinator's format. The Scheduling Coordinator would be Xcel's dispatch center
- Schedule validation
- Support the Accounting and Billing functions when requested
- Prepare Net-Short Position reports monthly
- Support the GM in developing the risk policy

The scheduling agent's contract should follow the same guidelines as the distribution contract, with less pressure on safety since it does not involve field work or high voltage. The clauses should include:

- Allow the City to hire another contractor (no monopoly of service)
- Limit contract term to 2 years, renewable annually.
- Set performance criteria for forecast and schedule accuracy, completeness and availability.
- Request a training program that City staff can attend.
- Request monthly operations report and meeting attendance.
- Indicate the City's desire to take over scheduling operations.

6.4.5 Scheduling Database

The scheduling agent, distribution contractor and the utility should develop a strategy for the scheduling database. Again, the GM should be careful not to commit the utility to built-in incompatibilities or proprietary issues that would prevent the utility from dismissing the contractor.

The database should remain the property of the City, although the software might be licensed from a third party. The scheduling database and software specifications should include the following capabilities as a minimum:

- Local server, with remote Demand Response server and back-up
- Fast technical support
- Easy interface with other databases, weather forecast, commodity pricing
- Interface with the Open Access Same Time Information System (OASIS) for the Rocky Mountain Region and Xcel.
- Approved interface with leading market suppliers and Scheduling Coordinator
- Automatic generator control (AGC) as an option
- Ease of configuration
- Data security
- Reporting capabilities with other common office software
- Expandability
- Speed of operation

The municipal utility should contact other utilities to discuss merits and pitfalls of common software packages.

6.4.6 Accounting and Billing

The accounting and billing department can be contracted or staffed from existing city departments and utilities. If contracted to a third party, the contract should follow the same guidelines as for the scheduling agent. The accounting and billing software should be the same platform as the Water and Wastewater Utility.

If the city decides not to outsource the Accounting and Billing functions, it should be able to rely on the Scheduling Department's support.

6.4.7 Final Notes on Operations Start-up

The utility set-up and staffing should take between 6 months and a year before the contractors are routinely running simulation exercises and ready to start real operations.

The Board and GM should be constantly aware of the following pitfalls:

- Conflicts of interest created by running too many functions with a single contractor, for example:
    - Having the scheduling agent own and operate generation
    - Having the distribution and metering contractor run the accounting and billing
    - Having Contractor stakeholders on the utility board
    - Software captivity:
    - Having a contractor provide or develop its operations software without proper legal safeguards that ensure the City's rights to continue operations after the contractor leaves.
    - Having obsolete or incompatible software
    - Underestimating the need for data storage and speed of operation

6.5 Simulations

With the key operation departments in place and setting up for operations, the utility should start running simulation exercises. The simulation phase entails running the utility as realistically as possible, with a Board, staff, software, up-to-date price and schedule information.

The distribution system's simulated operation and maintenance can include field surveys, training and drills. The scheduling simulation should include mock scheduling with the Balancing Area Controller (Xcel).

Simulation exercises will increase in scope as the utility staffs up and gears up its accounting department. They should also increase the accuracy of the data used in planning. The annual budget and rate structure should be revised accordingly.

7 Operations

The first day of operation should feel like "just another day" for the utility staff and board, except that trades and operations are no longer for exercise. The first month will require a higher level of effort in terms of scrutiny and information verification. The second month will require another level of effort as the financial settlements start coming in and need to be validated, likewise with vendor invoices. The effort level tapers down to a normal activity level for operations over the remainder of the year. Meanwhile the planning activity increases, first to compare the planning models with actual results and then to investigate alternative forms of resource procurement, cost impacts, rate structures and deployment of renewable strategies.

The first 3 years of operations should follow a conventional pattern of operations, although the utility may elect to commit to certain long-term resources such as the development of "localization assets," acquisition of renewable generation and/or transmission rights.

The unique character of the Boulder municipal utility, together with the results of its core value, will develop after the third to fifth year.

7.1 Legal Activities

Legal support is needed in all phases of the utility planning, inception and operation.

7.1.1 Legal for planning

The involvement of legal support is needed in the following planning activities:

- Communications with Xcel for data acquisition, stranded and acquisition costs determination.
- Understanding of regulatory compliance requirements from FERC, NERC and WECC for transmission, large generation permitting, renewable and intermittent generation.
- Coordination with Xcel for wholesale services such as transmission, network integration, ancillary services, etc.
- Understanding of State and Federal incentive programs for energy development, such as renewable financing.
- Drafting of the utility charter, bylaws, and governance.
- Bond financing
- Generator permitting for rooftop PV solar as well as large wind, hydropower, etc.

7.1.2 Legal for start-up

Legal support will be required during the following start-up activities:

- Stranded and acquisition costs negotiations with Xcel and FERC
- FERC filing for the new municipal utility
- Bond financing
- Initiating wholesale contracts with Xcel
- Transition of incentive programs from Xcel for roof-top PV Solar
- Power purchase agreements with third parties
- Sub-contractor hiring
- Staff hiring

8 Alternative Strategies

The following options should be studied early on before the utility is formed.

8.1 Early Repayment of Cash Reserve

The taxable bond finances the following items at 8 percent for 30 years:

- Acquisition of the Distribution assets: $121 million
- Severance of the distribution system: $15 million
- Utility operations reserve for 1 year: $12 million
- Energy and transmission cost reserve: $29 million

Acquisition and severance of the distribution system constitutes a tangible asset, which benefits the municipal utility bond rating.

Cash reserves represent $40 million, costing the utility an extra $52 million in bond par value and $4.7 million extra in annual debt service repayment. Under the base assumptions[6], the first two years would bring excess revenues of $66 million if the municipal utility rates matched the incumbent's. Depending on the bond structure, the municipal utility could potentially cancel its cash reserve in the third year and use 60 percent of its first two years' revenues for reserve. The advantage is that its reserve would then generate interest income.

8.2 Generation Asset Purchase

The utility will have the choice between Power Purchase Agreements (PPAs) and generator ownership. PPAs offer the advantages of procuring energy promptly and on a short-term basis.

[6] See Feasibility Study

Generator ownership involves a long-term commitment and may require 3 to 5 years to permit and build.

The municipal utility can pair its rates with the incumbent, resulting in the following net revenues to purchase generation:

Year	Net Revenue
2012	$36 million
2013	$30 million
2014	$7 million

Table 1: Initial Additional Revenues

An alternative to paying bonds early would be to purchase generation.

8.2.1 Wind Generation

The estimated cost for wind (Engineering, Permitting and Construction - EPC) is $2,125 per kW. Under the above assumption, the utility could have the following wind resources:

Year	Wind Capacity (MW)	Energy Purchase Reduction
2015	32	$4.3 million
2016	38	$5.5 million
2017	43	$6.5 million
2018	48	$7.7 million
2019	51	$8.5 million
2020	55	$9.6 million

Table 2: Wind Capacity Potential

Incidentally, new wind development less than 20 MW is not burdened by large generator interconnection requirements. The wind development results in net cost savings derived from the lesser reliance on wholesale purchases. The above results are preliminary, they assume:

- Zero energy cost from the wind resources since the utility owns the generators, transmission rates apply.
- No bond financing. Generator development is paid from utility revenues.
- 30 percent wind generation capacity factor (actual capacity factor is upwards of 40 percent[7])

[7] XCEL Energy used a 47 percent capacity factor in their wind proposal

The result is an alternative form of cost parity with the incumbent utility. This strategy has the following benefits:

- Generation asset acquisition
- Additional revenues from Renewable Energy Credits (not included in the above numbers)
- 7 percent renewable portfolio owned by the utility in addition to the grid RPS in 2020.
- 6 percent reduction from fossil fuel generation (natural gas and coal)
- Benefits can be captured as rate stabilization (dashed line in figure 3 below) with a long-term rate reduction.

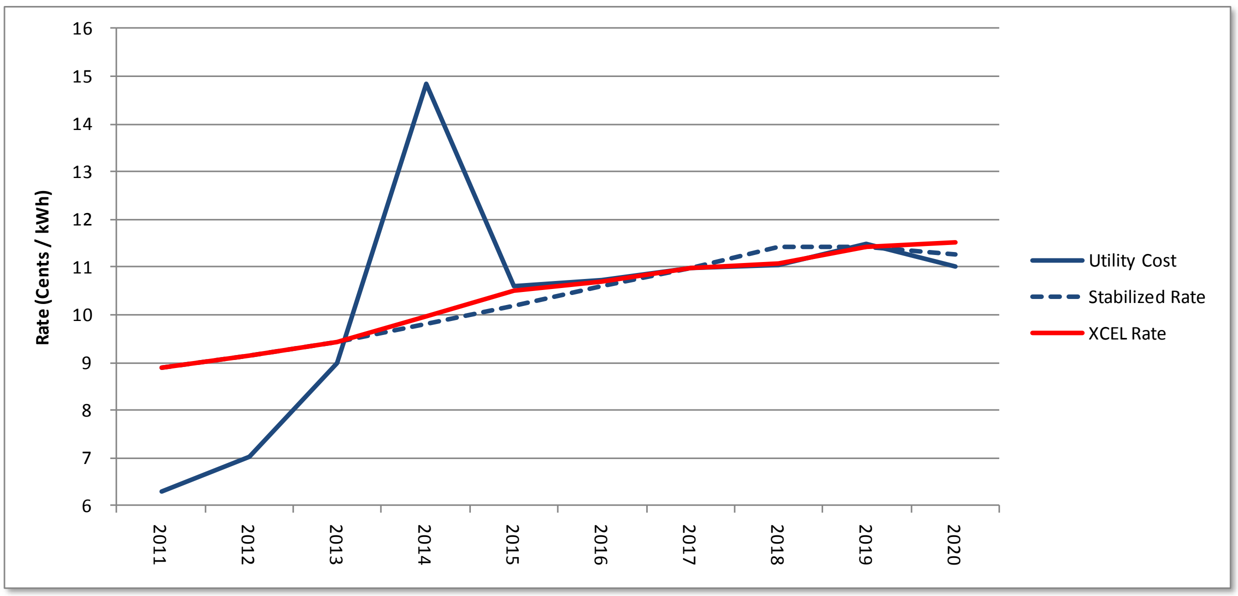

Figure 3: Comparative Rates

8.2.2 Gas Generation

The same reasoning can be held for a natural gas generator as for wind. The gas generators would not protect the utility from the volatility of natural gas prices, but would provide a firming resource and capacity reserve. The natural gas generators could be specified to run on multiple fuels, such as gas or liquid bio-fuels.

The specifications for gas generation are:

- 9,800 BTU / kWh Heat Rate (Lower Heating Value)
- $1.1 million per MW installed (Engineering, Permitting, Construction)
- 100 percent capacity factor during on-peak hours. Not competitive against off-peak wholesale market.

Year	Gas Capacity (MW)	Energy Purchase Reduction
2015	34	$0.5 million
2016	62	$0.9 million
2017	70	$1.0 million
2018	80	$2.1 million
2019	84	$2.0 million
2020	84	$2.2 million

Table 3: Gas Generation Potential

Even if installed locally to offset transmission charges, the gas generator shows a marginal advantage. The results shown in table 3 above could be further improved if the gas generation was used on an economic dispatch basis against wholesale market.

8.2.3 PV Solar Generation

PV solar is typically installed “behind the meter” and the energy generation is first absorbed by the customer, with the surplus sent to the distribution grid. Behind-the-meter generation results in load reduction and therefore higher cost allocation to the remaining load. Pushing the idea to the extreme, if PV Solar were to completely offset the residential load, it is easy to visualize how the remaining 78 percent load carries the entire utility fixed costs. This risk can be addressed with tiered rebates and purchase prices. The following proposal focuses on a first tier generation of PV-Solar installation.

The two main options to purchase solar generation are to pay a rate derived from the capital cost, typically upwards of 18 cents per kWh, or to contribute to the capital investment with a rebate and purchase the energy at a discount. The former solution can be implemented without affecting the utility’s capital reserve, but it affects energy costs because the generation rate is several times higher than market. The later is a joint venture between the utility and its customer that has significant benefits to all parties.

Supposing that the municipal utility implements a solar program with the following parameters:

- Installation rebate: $1.75 per Watt
- REC purchase: 4 cents per kWh ($40 per MWh)

The solar generation can be deployed relatively quickly, compared to wind and natural gas. The table below summarizes the potential PV Solar deployment and utility cost reduction.

Year	PV Solar Capacity (MW)	Energy Purchase Reduction
2013	18.5	$0.3 million
2014	30	$0.6 million
2015	33	$ 0.8 million
2016	36	$1.0 million
2017	39	$1.2 million
2018	42	$1.5 million
2019	42	$1.7 million
2020	43	$1.8 million

Table 4: PV Solar Generation Potential

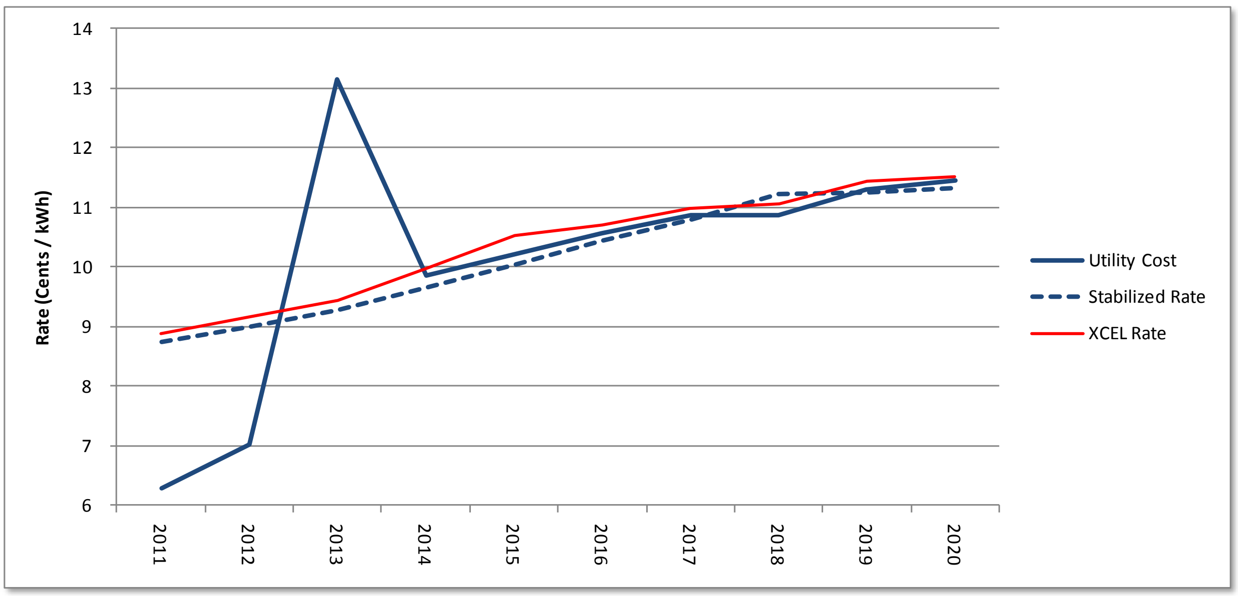

Figure 4: Comparative Rates

The solar program presents the following advantages:

- Solid growth in savings
- Local resource and economy
- Flexibility to implement program variants for higher returns
- Can be applied to thermal solar with even higher returns

The disadvantages include:

- Reliance on overseas manufacturing
- Customer tolerance for higher rates
- Need for energy storage

It seems that photovoltaic technology has broken new ground for distributed generation; however, the future will likely turn to solar thermal electric generation.

8.3 Alternative to Severance

This last topic addresses the $15 million set aside for the severance of the distribution system, which costs an additional $4.5 million in bond debt service reserve and capitalized interest. The severance costs the utility an extra $2.1 million in annual debt service payment over 30 years. This is a high price to pay and the City should consider alternatives such as:

- Servicing all customers connected to the City substations. The City would have to file rates with the Public Utility Commission to retail outside of its limits.
- Annexing the areas connected to the municipal electric utility
- Passing through Xcel charges

9 Conclusion

The business plan outlines the creation, start-up and operation of the municipal electric utility. The costs are based on the feasibility study. The upcoming November 1st election is the last determinant to the feasibility of the municipal utility; based on a positive outcome, the City should then review carefully each step of the utility creation in order to define its transition period, conduct follow-up studies and potentially adjust its bond requirement.

The municipal utility will rely on wholesale market energy for the first 3 years and it should hedge against price volatility by securing liquidated damage contracts as early as possible. The first 3 years will likely yield higher than average revenues commensurate with the delay in bond repayment. The utility needs to weigh all its options for near- and long-term goal achievement. Three options discussed in this report entail using the initial profits to buy down the rates over the next 7 years, acquire 84 MW of natural gas generation, develop 43 MW of rooftop solar, or acquire 55 MW of wind generation. The final answer may be a mix of the above.

In addition to the initial profit margin, the utility will generate upwards of $4 million annually in public purpose program funding. This will replace Xcel's current demand-side management spending in Boulder, as well as the current Climate Action Plan tax. This funding should be assessed for efficiencies and can be used to fuel additional research and development with local enterprises, laboratories and academia to ultimately lead to the Boulder solution to rate stability, system reliability carbon reduction and maximum localization.

Appendix A

Load, Resources, Trading And Scheduling

The City load must be met on an hourly basis with energy supply. This section describes the process of load balancing.

Aggregated City Load

The incumbent utility has provided the 2010 hourly load data after numerous requests from the City.

The table below summarizes key load profile characteristics of the actual City 2010 load profile:

Load factor	68 percent
Peak demand	236 MW in July
Base load	116 MW
Annual energy	1,396,234 MWh
Annual growth	1.80 percent

Table 1: Load profile characteristics

The figure below shows the monthly average City load profile.

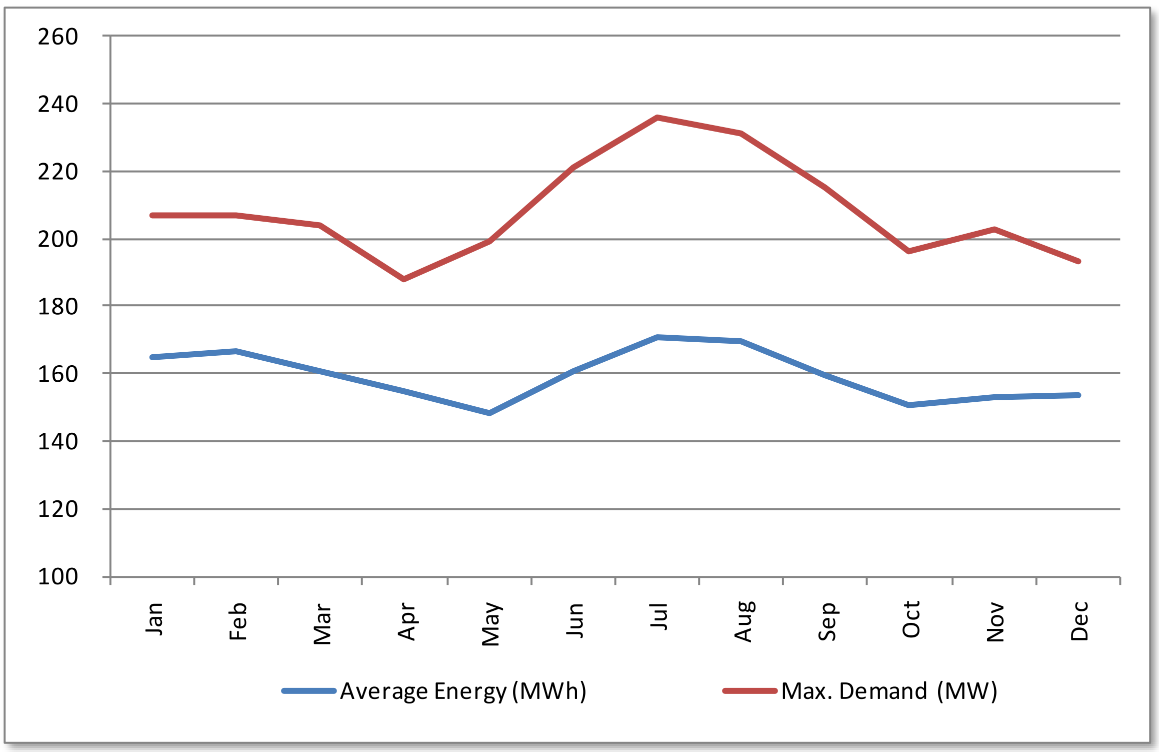

Figure 1: City load profile

Renewable Resources

The renewable resource modeled for the study entails the City-owned hydroelectric generation.

It is assumed that the energy rate is the cost to operate the hydro, $45.60 per MWh in 2008, and that there is no transmission charge. The City-owned hydroelectric plants include:

- Maxwell
- Orodell
- Kossler
- Sunshine
- Betasso / Lakewood
- Silver Lake
- Boulder Canyon

The model uses actual hourly output from PV-Solar panels located in Boulder:

PVWATTS: Hourly PV Performance Data, 1962 to 1990[8]

City:	BOULDER
State:	Colorado
Lat (deg N):	40.02
Long (deg W):	105.25
Elev (m):	1634
Array Type:	Fixed Tilt
Array Tilt (deg):	40.0
Array Azimuth (deg):	180.0
DC Rating (kW):	10.0
DC to AC Derate Factor:	0.770
AC Rating (kW):	7.7

The actual data brings the intermittency of solar generation, as shown in the figure below.

[8] Courtesy of RenewableYES, T. Asprey.

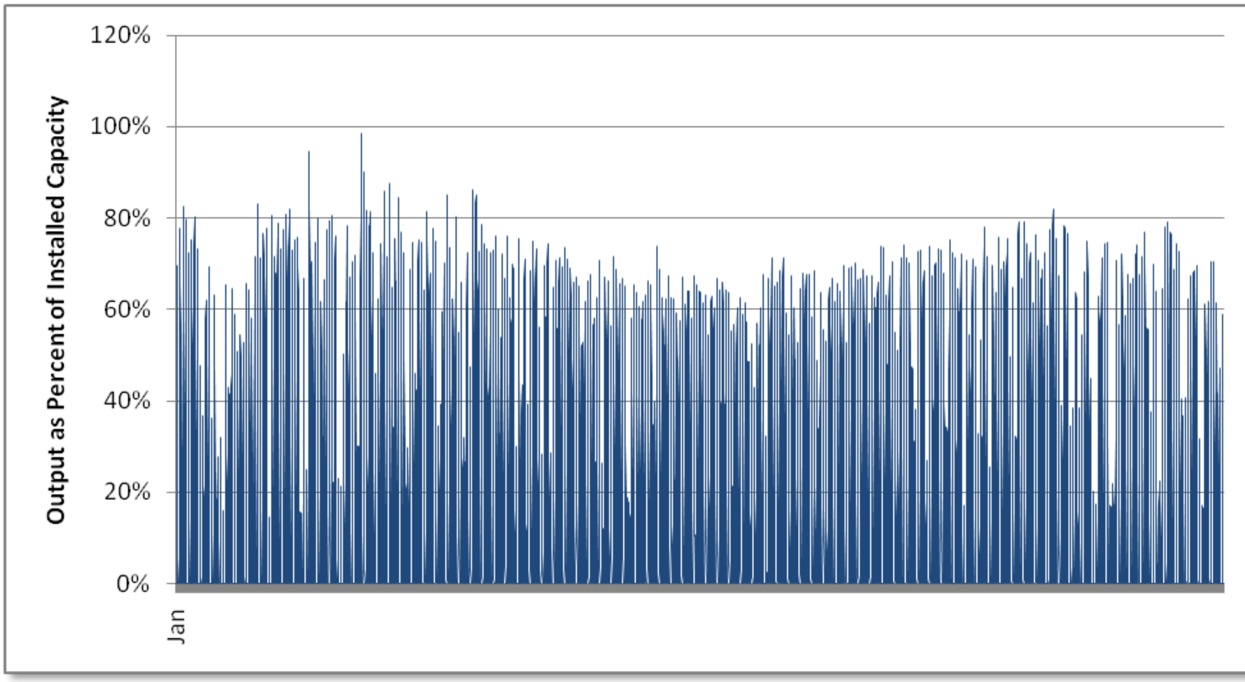

Figure 2: Hourly solar generation for a year

Wind generation is based on east Colorado plains data. The rate used for wind, at 6.5 cents per kWh, is reasonably higher than the current ongoing rate of 5.5 cents. The wind generation profile stems from the NREL site id 12883 for 2006:

State:	Colorado
Lat (deg N):	40.41
Long (deg W):	102.19
Elev (m):	1127

The wind generator is located approximately 7 miles north of Holyoke, CO. The 10-minute dataset was averaged to hourly readings. The hour-averaged wind data, depicted in the figure below, provides enough intermittency for the model.

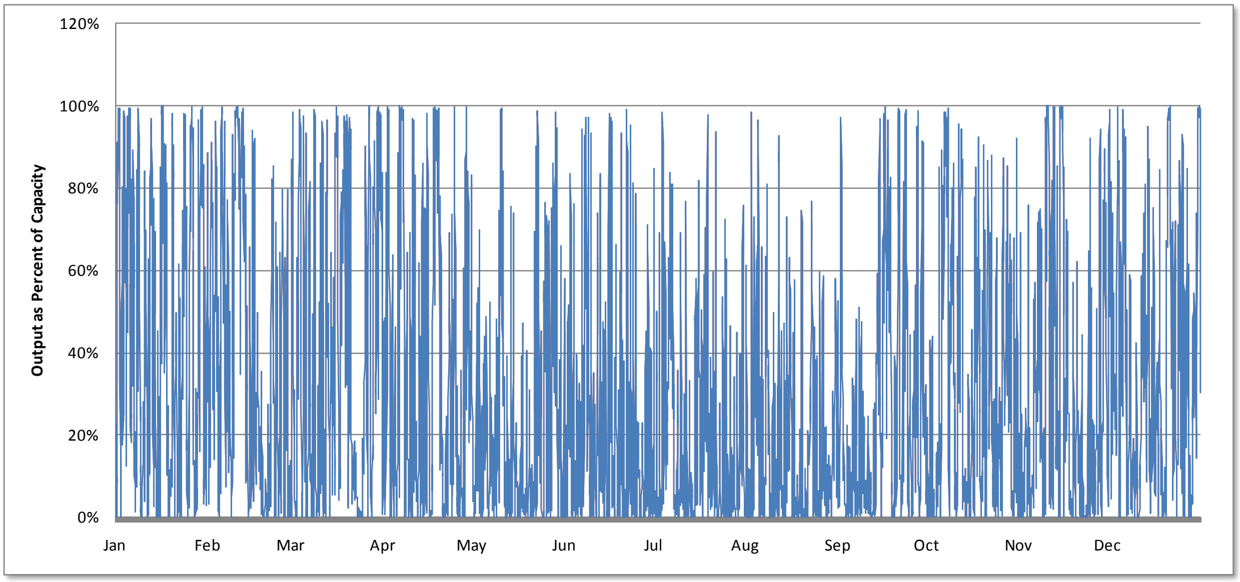

Figure 5: Annual Wind Generation Profile

The table below summarizes the PV-Solar and wind rates and characteristics.

	PV Solar	Wind
Installation Rebate	$ 1.75 / Watt	N/A
Rate	$40/ MWh (4 cents per kWh)	N/A
Load Factor	17 percent	30 percent
Actual curve from	PVWATTS	NREL

Table 2: PV-Solar and wind model parameters

The model computes load and resources with a granularity of one hour over 10 years.

Supplemental Market Energy

The operation of an electric utility requires that the resources match the planned load every hour. The wholesale energy market offers different options to procure supplemental energy, or sell back surplus energy. The market energy is supplied from non-designated resources, meaning that Boulder would only need to schedule a purchase or a sale at given hours with a counterparty, without specifying which generator the energy comes from.

Wholesale market trades are an agreement between Boulder, a counterparty and Xcel Energy.

- Boulder purchases energy from a counterparty, asking it to deliver it on the Xcel grid
- Xcel is notified of the delivery on behalf of Boulder so that Xcel knows the Boulder load is balanced with the resource
- Xcel takes the energy on its network and delivers a similar amount of energy from its grid to Boulder. Xcel does not charge Boulder or credit the counterparty for the energy.
- Boulder pays the market counterparty for the energy purchased and Xcel for the transmission charges

Wholesale market energy trades can take several forms: Future purchases, day-ahead and real time.

Future Purchases

Future purchases – or Liquidated Damage Contracts – are used to protect against the volatility of the spot market in future months and years, it is a form of hedging. This type of transaction, primarily as a purchase, consists in buying blocks of energy for a period of time in the future at a fixed price. For example, the utility might consider today buying 100 MW for each on-peak hour in July 2013 at $63.00/MWh from counterparty X. This purchase creates an obligation for the counterparty X to deliver 100 MWh at $63.00/MWh on the grid on behalf of Boulder at each on-peak hour during July 2013; it also creates an obligation for Boulder to take the energy and pay the counterparty. If the market rate drops to $30.00/MWh in July 2013, Boulder is still obligated to buy the energy at $63.00/MWh; conversely if the market price jumps to $120/MWh, the counterparty is still obligated to sell the energy at $63.00/MWh to Boulder. Now suppose that Boulder only needed 43 MW at a given hour, it can sell back the 57 MW surplus on the market. The sale may be at a profit or at a loss, depending on the spot market price at that time. Future purchases are an insurance policy, they seldom result in competitive pricing at the time of delivery but they do protect against price spikes.

Day-Ahead Market

Day-ahead market (DAM) trades can be purchases or sales (called CALL and PUT, BUY and SELL in the energy parlance). Unlike future purchases, DAM trades are executed two days prior to the delivery date for variable amounts of hourly energy, and priced according to an index such as the Intercontinental Exchange (ICE) for the particular region where energy is delivered. In trading on the day-ahead market, the municipal utility would purchase the energy, priced at an index, plus a margin; it would sell the energy, priced at the index, minus a trade margin.

Real Time Market

Real time market (RTM) trades are a corrective tool to adjust a schedule within an hour of delivery in the event that the load or generation appears to differ substantially from what was scheduled on the day-ahead market.

Examples of scheduling mishaps include:

- Sudden weather change, resulting in substantial increase or decrease of air conditioning load
- Failure at a substation or distribution feed, resulting in a sudden load drop.
- Large customer back-up generator start, resulting in a sudden load decrease.
- Generator failure or malfunction.

Real time market trades are used to avoid costly imbalance charges. The municipal utility has a +/- 2 MW error band for its scheduling accuracy, within which it does not incur penalties. Beyond this dead band, Xcel charges up to 125 percent for under-schedules and credits as little as 75 percent for over-schedules.

Load and Resource Scheduling

Load and corresponding resources will need to be forecasted and scheduled by the municipal utility. This requires Boulder to have scheduling agents who will submit the schedules to a Scheduling Coordinator. The Scheduling Coordinator (SC) is responsible for submitting the schedule to the grid operator, which is Xcel. For SC services; Boulder can become its own SC, hire Xcel, or a third party consultant.

Day-Ahead Scheduling

Day Ahead scheduling consists in balancing the load with resources on a 36-hour forecast basis, and using day-ahead market trades to supplement generation. In other words, at each hour:

Day-Ahead load forecast = Day-Ahead generation forecast + Day-Ahead Market resources

Hourly load can be routinely forecasted by computer according to patterns and select variables.

Generation day-ahead forecast is instruction-based for firm generation (hydro, biogas, natural gas) but intermittent resources such as wind and PV-Solar are far more challenging as they require a best guess of the next 36 hour weather conditions. Intermittent resources are scheduled on an average basis on the day-ahead, and corrected on a real-time basis.

Day Ahead Scheduling is handled during normal business hours. Subject to clarifications from the Scheduling Coordinator (SC), the schedule can be placed on a two-day ahead during business hours to ensure the SC has received scheduling instructions by 6:00 am on the day ahead.

		Monday	Tuesday	Wednesday	Thursday	Friday
	HE	Scheduling Day for Tuesday	Scheduling Day for Wednesday	Scheduling Day for Thursday	Scheduling Day for Friday & Saturday	Scheduling Day for Sunday & Monday
Market: day ahead trading	0600	Customer provides SC and market provider with a copy of its load and resource schedules for Tuesday	Customer provides SC and market provider with a copy of its load and resource schedules for Wednesday	Customer provides SC and market provider with a copy of its load and resource schedules for Thursday	Customer provides SC and market provider with a copy of its load and resource schedules for Friday & Saturday	Customer provides SC and market provider with a copy of its load and resource schedules for Sunday & Monday

Table 3: Day Ahead Trading Schedule

The daily scheduling requires one staff; it is desirable to have at least three to four staff taking turn in the day-ahead scheduling for redundancy.

The example schedule below shows the following elements of a daily schedule:

- Hourly load forecast. The load is net of local resources, that is total load minus local generation. It is then increased by 5 percent to compensate for transmission losses.
- Resource schedule for the wholesale energy, including renewable resources, day-ahead trades and a future purchase
- The summary of net energy trade for the scheduling coordinator (SC). In the case of Boulder, the SC could be XCEL Energy.
- The schedule shows on-peak hours to be from 6 am to 10 pm. In Colorado, peak hours are from 7 am to 11 pm.

Schedule Coordinator ID:XXXXX
Schedule For: **Thursday 08/11/2005**

	Net Load	RESOURCE												
		Hydro	Market Counterparty 1				Market Counterparty 2				FIXED		Summary for SC	
Hour Ending	Total		Call	Put	Buy	Sell	Call	Put	Buy	Sell	(Future)		Buy	Sell
1	60.47	8	52	0	0	0	0	0	0	0	0	MW	52	0
2	60.46	8	52	0	0	0	0	0	0	0	0	MW	52	0
3	60.42	8	52	0	0	0	0	0	0	0	0	MW	52	0
4	60.48	9	52	0	0	0	0	0	0	0	0	MW	52	0
5	60.69	8	52	0	0	0	0	0	0	0	0	MW	52	0
6	60.65	8	52	0	0	0	0	0	0	0	0	MW	52	0
7	61.23	54	0	34	1	0	0	0	0	0	40	MW	1	34
8	61.88	55	0	34	0	0	0	0	0	0	40	MW	0	34
9	62.29	55	0	34	1	0	0	0	0	0	40	MW	1	34
10	62.56	56	0	34	0	0	0	0	0	0	40	MW	0	34
11	62.54	57	0	34	0	0	0	0	0	0	40	MW	0	34
12	62.23	56	0	34	0	0	0	0	0	0	40	MW	0	34
13	61.64	56	0	34	0	0	0	0	0	0	40	MW	0	34
14	60.87	55	0	34	0	0	0	0	0	0	40	MW	0	34
15	60.11	54	0	34	0	0	0	0	0	0	40	MW	0	34
16	59.32	56	0	34	0	2	0	0	0	0	40	MW	0	36
17	58.71	52	0	34	0	0	0	0	0	0	40	MW	0	34
18	58.47	52	0	34	0	0	0	0	0	0	40	MW	0	34
19	58.7	52	0	34	0	0	0	0	0	0	40	MW	0	34
20	59.18	52	0	34	1	0	0	0	0	0	40	MW	1	34
21	59.59	53	0	34	0	0	0	0	0	0	40	MW	0	34
22	59.81	53	0	34	0	0	0	0	0	0	40	MW	0	34
23	59.88	8	52	0	0	0	0	0	0	0	0	MW	52	0
24	59.93	8	52	0	0	0	0	0	0	0	0	MW	52	0
TOTALS	**1452.09**	**933**	**416**	**544**	**3**	**2**	**0**	**0**	**0**	**0**	**640**	MWH	**419**	**546**

Table 4: Example of day-ahead energy schedule

Real Time Scheduling

Utilities operating in a deregulated market (Independent System Operators, ISO), generator owners and Regional Transmission Operators (RTO) such as Xcel and WAPA, have a 24-hour desk for real time market trades. The motivations are:

- An ISO utility may see financial value in arbitraging the hourly market prices.
- An RTO needs to ensure grid integrity around the clock.
- Generator owners (power producers) need to respond to instructions from the RTO dispatch center.

The City's utility may want to delay the decision to have a 24-hour desk because it adds a layer of staffing complexity, cost and stress that may not be justified. Short-term alternatives include:

- Having a staff on call
- Contracting with an SC for real-time trading

Once the City acquires large intermittent generation (above 20 MW) such as wind, or deploys enough local resources (distributed generation, storage), it needs to have staff round the clock comprised of a 24-hour desk and ground technicians.

Appendix B

Bond Financing

The City envisions financing the municipal utility start-up with revenue bonds. The feasibility study modeled the financing as a being from a combination of taxable and a non-taxable revenue bonds, using 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 1: Bond Financing Parameters

The financing entails the following:

- Acquisition Cost (taxable): $121 million
- Energy reserve fund (taxable): $29 million
- Utility O&M reserve fund (taxable): $12 million
- Severance cost (taxable): $15 million
- Start-up logistics (non taxable): $32.5 million
- Start-up legal and engineering (non taxable): $3 million
- Capital spares (non taxable): $10 million

The taxable bond has a coupon rate at 8 percent and the non-taxable bond rate is set at 5.76 percent. The bonds will be issued under competitive bids as mandated by the city charter.

The bonds are modeled as carrying 1.5 years of capitalized interest and 10 percent debt service reserve (DSR), which together with an 8 percent coupon rate on the taxable bond, result in a 1.3 load factor on the financed amount.

The city will review carefully the utility financing options at start-up time based on actual acquisition, stranded costs and detailed start-up and severance cost estimates. One clause the city needs to negotiate is that of early payment, bond reduction and early bond repayment, as early repayment of bonds could save the utility substantial expenses in later years.

BOULDER MUNICIPAL UTILITY

BUSINESS PLAN

ADDENDUM

Prepared for:

City of Boulder

Prepared by:

Robertson - Bryan, Inc.
Solutions for Progress

August 16, 2011

1 Introduction

In the original feasibility study and business plan, the municipal utility would cover its net short energy position (load minus generation) with wholesale market energy. While this approach may reflect the initial mode of operation for a local utility, it does not significantly reduce the coal component of the energy mix.

The following business plan addendum summarizes the greenhouse gas emission reductions and renewable energy development, financed from utility revenues rather than from initial bonding, if the municipal utility would cover its net short position with natural gas generation instead of wholesale market energy. Natural gas generation would consist of simple cycle gas turbine for the firming of the wind resource and combined cycle gas generation for the net short. For the purpose of this analysis, both types of gas plants are shown to be contracted under Power Purchase Agreements rather than being owned by the city.

Importantly, this analysis is not a resource planning effort. It is an illustrative example of a way to mitigate carbon by increasing renewable energy and natural gas. If a local utility is formed, a resource planning effort would be initiated, and various other approaches would be explored and developed, based on the goals of the utility.

2 Key Parameters

NATURAL GAS GENERATION

The cost of natural gas is issued from the 30-year monthly market projection at El Paso San Juan, cost at burner tip. In addition, a $0.60 per MM BTU gas delivery charge was added as a conservative measure. Although the municipal utility would not acquire the gas generators, it is assumed that it would purchase the gas on behalf of the plant owners according to a heat rate contract.

The combustion turbine (CT) is used to firm up the wind intermittency. The heat rate is 9,435 BTU / kWh, with seasonal derating up to 10 percent in the summer months. Hence the summer heat rate would be 10,379 BTU / kWh. A capacity charge is applied to the CT cost in addition to the energy delivered. The capacity payment starts at $2,000 per MW-month and increases as a function of the projected capacity charges from independent projection.

The combined cycle plant (CC) is used to cover the net short position in replacement of the wholesale market. The heat rate is 8,000 BTU / kWh, with a similar seasonal derating up to 10 percent in the summer months.

Income In Lieu of Taxes

In addition to the deployment of PV solar generation, the models were amended to increase funds from PILOT and Public Purpose Program Fund 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.

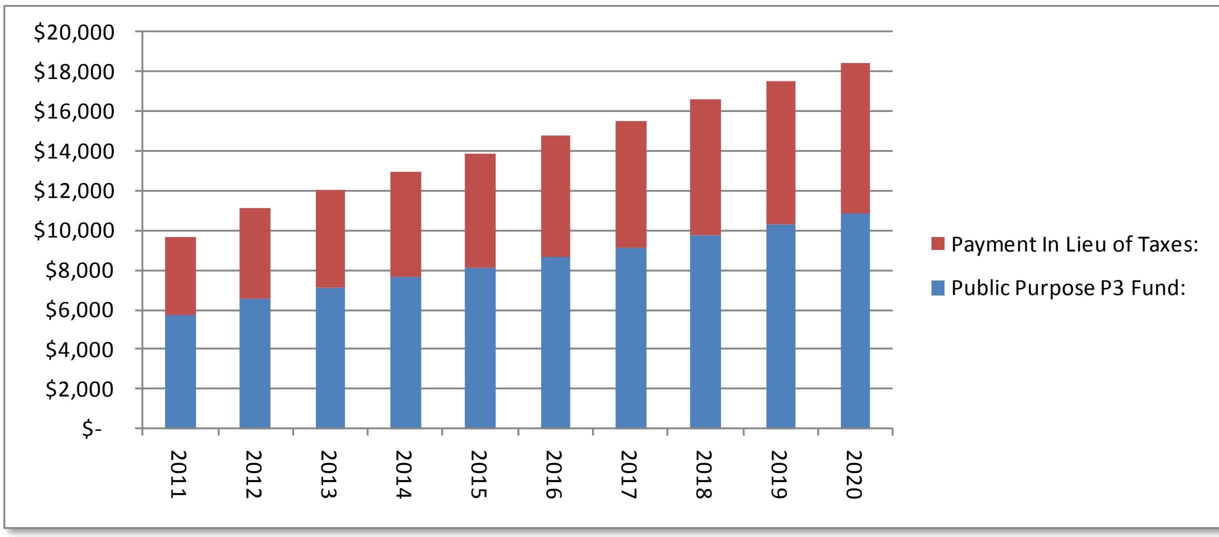

Figure 1: Projected Revenues from PILOT and P3

Other Parameters

Other fixed parameters include:

- Minimum Debt Service Coverage ratio of 1.5, as in the original feasibility study.
- Bond parameters: same as the original feasibility study.

The following sections describe three alternative power supply cases with reduced carbon emission which build upon the initial cost model assumptions:

1. Case 1: Initial cost model case replacing net short position with combined cycle natural gas instead of wholesale market energy

2. Case 2: Initial cost model case adding wind energy generation firmed with natural gas, replacing net short position with combined cycle natural gas instead of wholesale market energy

3. Case 3: Initial cost model case adding solar PV generation with combined cycle natural gas, replacing net short position with combined cycle natural gas instead of wholesale market energy

3 Case 1: Combined Cycle Natural Gas

Case 1 consists of the following resource portfolio:

- City-owned hydropower
- Minimal PV Solar power, as shown in table 1
- No wind, therefore no firming resource
- Supplement: combined cycle natural gas plant

	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 1: Installation of PV Solar – Distributed Generation

Table 2 shows the resulting RPS and carbon reduction.

	2011	2014	2016	2018	2020
Local Renewable Resources:	3%	4%	4%	4%	5%
Boulder Renewable Portfolio:	3%	4%	4%	4%	5%
Boulder Emissions (lb CO2e / MWh):	**873**	**868**	**865**	**863**	**860**
Xcel Renewable Portfolio:	15%	21%	24%	26%	37%
Xcel Emissions (lb CO2e / MWh):	*1,478*	*1,376*	*1,316*	*1,220*	*1,137*

Table 2: RPS and Carbon Reduction – Case 1

The 10-year Savings NPV against XCEL's revenues is $45.7 million

The 10-year average composite rate (stabilized) is 7 percent below XCEL, as shown in figure 2 below.

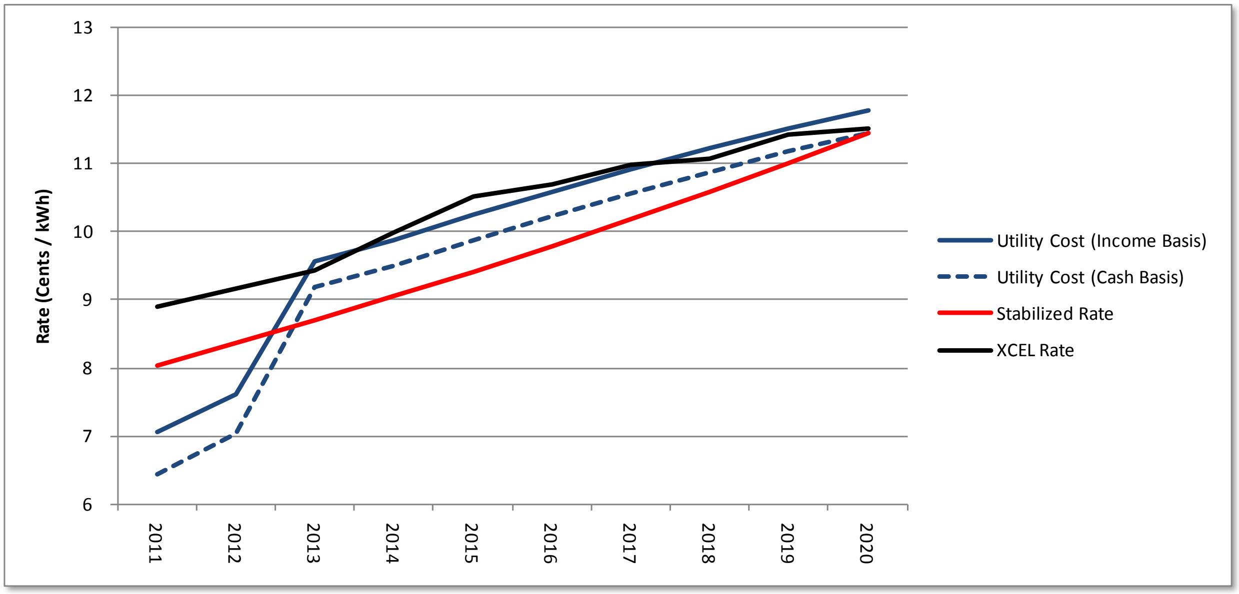

Figure 2: Composite Rate Comparison – Case 1

The Case 1 scenario results in increasing energy savings when compared to the initial case[1] with wholesale market energy. Initial loss of $3.8 million in year 1 gradually changes to a positive saving of $4.7 million in 2020.

COST MODEL STABILIZED COMPOSITE RATES ($/MWh)						
Year	Residential	Commercial	Industrial	Other / SL	City of Boulder	Xcel
2011	109.15	75.64	100.53	237.45	80.43	88.87
2012	113.52	78.66	104.55	246.95	83.64	91.59
2013	118.06	81.81	108.74	256.83	86.99	94.31
2014	122.78	85.08	113.09	267.10	90.47	99.76
2015	127.69	88.49	117.61	277.78	94.09	105.20
2016	132.80	92.03	122.31	288.89	97.85	107.01
2017	138.11	95.71	127.21	300.45	101.77	109.73
2018	143.63	99.54	132.29	312.47	105.84	110.64
2019	149.38	103.52	137.59	324.97	110.07	114.27
2020	155.35	107.66	143.09	337.96	114.47	115.17

Table 3: Retail Rate Allocation – Case 1

[1] In this report addendum, "initial case" refers to the prior studies where wholesale market energy is used to supplement renewable resources.

4 Case 2: Maximum Firm Wind

This scenario reviews adding wind generation to the initial case. Wind intermittency would be firmed by a combustion turbine.

Engineering, permitting and construction (EPC) is assumed to take 5 years, therefore the first wind generation would be deployed in 2015. The municipal utility would acquire the wind generation at an EPC cost of $2.125 million per MW, financed entirely from revenues. EPC cost is escalated annually by 2.5 percent.

Table 4 shows the installed generation capacity.

	2011	2012	2014	2015	2016	2018	2020
PV Solar (MW)	2.23	8.92	8.92	11.15	13.38	17.84	22.30
Firm Wind (MW)	-	-	-	28.00	35.00	41.00	41.00

Table 4: Installed Generation Capacity – Case 2: Max Firm Wind

Table 5 shows the resulting RPS and carbon reduction.

	2011	2012	2014	2015	2016	2018	2020
Local Renewable Resources:	3%	4%	4%	9%	10%	11%	11%
Boulder Renewable Portfolio:	3%	4%	4%	9%	10%	11%	11%
Boulder Emissions (lb CO2e / MWh):	**873**	**871**	**868**	**824**	**812**	**802**	**802**
Xcel Renewable Portfolio:	15%	14%	21%	22%	24%	26%	37%
Xcel Emissions (lb CO2e / MWh):	*1,478*	*1,454*	*1,376*	*1,341*	*1,316*	*1,220*	*1,137*

Table 5: RPS and Carbon Emissions – Case 2: Max Firm Wind

A 10-year NPV against XCEL's revenues of zero provides rate parity, as shown in Figure 3 below.

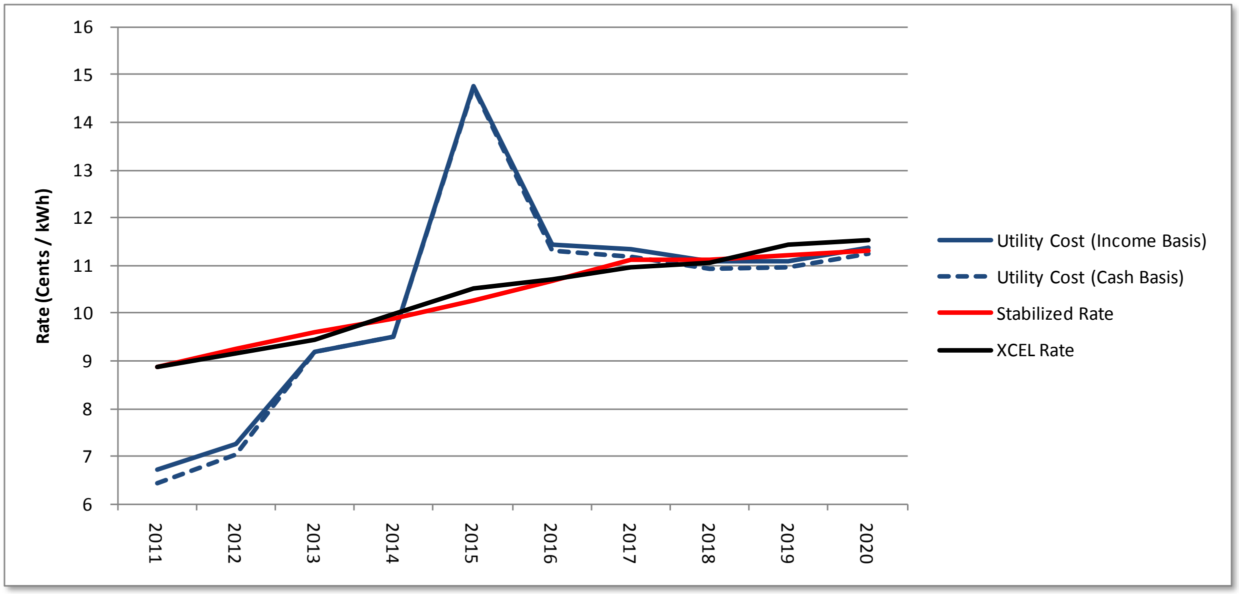

Figure 3: Composite Rates – Max Firm Wind

The maximum firm wind scenario results in increased energy savings. When compared to the initial case (with wholesale market energy), initial loss of $3.6 million in year 1 gradually changes to a positive saving of $9.1 million in 2020 from avoided energy purchases.

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	120.61	83.58	111.09	262.39	88.87	88.87
2012	125.44	86.93	115.54	272.88	92.43	91.59
2013	130.12	90.17	119.85	283.07	95.88	94.31
2014	133.99	92.85	123.41	291.48	98.73	99.76
2015	139.35	96.56	128.35	303.14	102.68	105.20
2016	144.92	100.43	133.48	315.27	106.78	107.01
2017	150.72	104.44	138.82	327.88	111.05	109.73
2018	150.78	104.49	138.88	328.01	111.10	110.64
2019	152.00	105.33	140.00	330.67	112.00	114.27
2020	153.36	106.27	141.25	333.62	113.00	115.17

Table 6: Retail Composite Rates – Case 2: Max Firm Wind

5 Case 3: Maximum PV Solar

This scenario reviews adding PV solar generation to Case 2 in place of the wind. Solar financing conforms to Case 2, with similar rebate payments and REC purchase prices derived entirely from the utility revenues.

Table 7 shows the installed generation capacity.

	2011	2012	2013	2014	2015	2016	2018	2020
PV Solar (MW)	2.50	15.00	35.00	54.00	60.00	65.00	75.00	75.00
Firm Wind (MW)	-	-	-	-	-	-	-	-

Table 7: Installed Resources – Case 3: Max PV Solar

Table 8 shows the resulting RPS and carbon reduction.

	2011	2012	2013	2014	2015	2016	2018	2020
Local Renewable Resources:	3%	5%	7%	8%	9%	9%	10%	10%
Boulder Renewable Portfolio:	3%	5%	7%	8%	9%	9%	10%	10%
Boulder Emissions (lb CO2e / MWh):	**873**	**862**	**844**	**827**	**823**	**820**	**814**	**817**
Xcel Renewable Portfolio:	15%	14%	18%	21%	22%	24%	26%	37%
Xcel Emissions (lb CO2e / MWh):	*1,478*	*1,454*	*1,430*	*1,376*	*1,341*	*1,316*	*1,220*	*1,137*

Table 8: RPS and Carbon Emissions – Case 3: Max PV Solar

A 10-year NPV against XCEL's revenues of zero provides rate parity, as shown in figure 4 below.

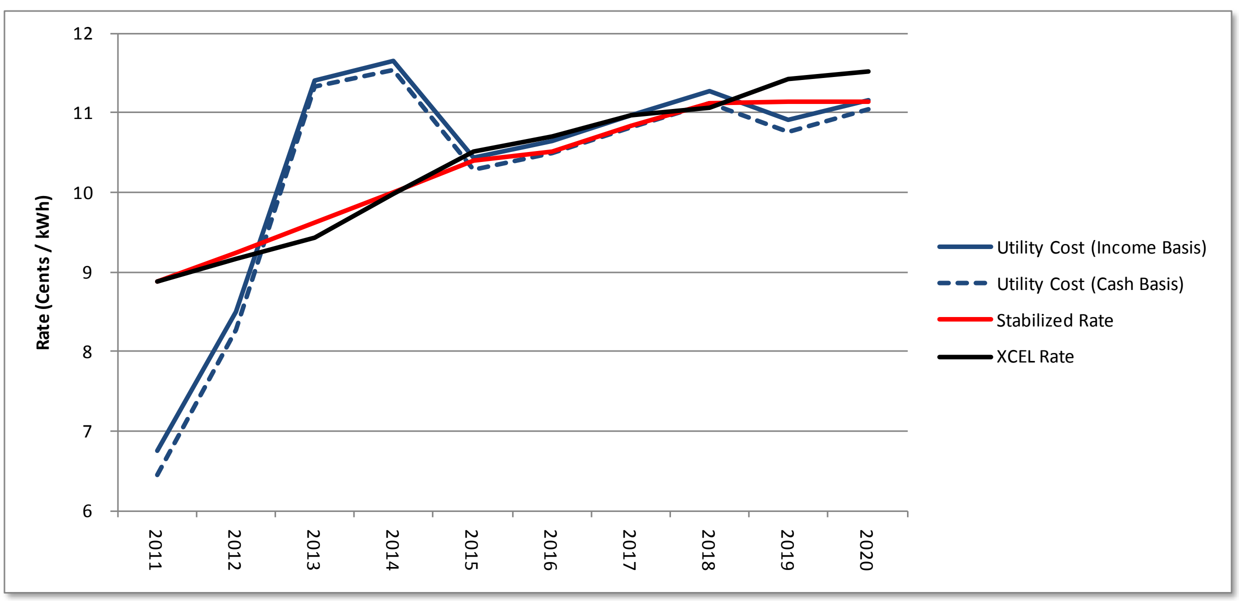

Figure 4: Composite Rates – Case 3: Max PV Solar

The maximum solar scenario results in increased energy savings. When compared to the initial case (with wholesale market energy), initial loss of $3.7 million in year 1 gradually changes to a positive saving of $11.7 million in 2020 from avoided energy purchases.

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	120.65	83.61	111.13	262.47	88.90	88.87
2012	125.48	86.95	115.57	272.97	92.46	91.59
2013	130.50	90.43	120.19	283.88	96.15	94.31
2014	135.71	94.05	125.00	295.24	100.00	99.76
2015	141.14	97.81	130.00	307.05	104.00	105.20
2016	142.77	98.94	131.50	310.59	105.20	107.01
2017	146.98	101.85	135.38	319.74	108.30	109.73
2018	151.05	104.68	139.13	328.60	111.30	110.64
2019	151.32	104.86	139.38	329.19	111.50	114.27
2020	151.32	104.86	139.38	329.19	111.50	115.17

Table 9: Retail Composite Rates – Case 3: Max Solar

6 Conclusion

This addendum to the business plan 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:

- High rate of renewable deployment, entirely funded by operations revenue
- Significant reduction in carbon emissions compared to Xcel's projected fuel mix
- The utility would meet the state RPS for municipal utilities of 10 percent renewable by 2020
- Higher contribution to City, County and School District taxes
- Increased rate stability with a maximum 4 percent annual increase over 10 years

The results reflect a high-level modeling of natural gas generation, independent power producers have not been solicited for input on the assumed heat rate contracts. Nevertheless, the upcoming amount of stranded independent natural gas generation will lend to very competitive bidding in 2015.

Wind generation is likely to be deployed faster than 5 years, given the current amount of shovel-ready projects on the east plains. Gas firming costs are penalizing the model due to a simplistic representation; actual firming would account for economic dispatch and would probably not occur during the off-peak hours. Renewable developments are entirely financed from operation revenues and, together with the cost of firming, result in a likely lower rate of development than actual.

The maximum solar development case is not hindered by the firming resource cost however the model does not account for rate increase caused by load reduction. This can be mitigated in actuality with demand capacity charges to compensate for generation intermittency.

Whether it is from wind, solar or a mix of the two resources, renewable developments financed from operations revenues provide an effective savings from avoided costs of energy purchases. The value of a resource is its ability to displace a more expensive one; to this end, PV Solar seems more effective than firm wind.