Organizational and Financial Review of Electric City Power

November 2009

Project 53421

Burns & McDonnell
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Organizational and Financial Review of Electric City Power

prepared for

City of Great Falls

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prepared by

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

SECTION 1.0

INTRODUCTION AND BACKGROUND

1.0 INTRODUCTION AND BACKGROUND

Burns & McDonnell Engineering Company, Inc. (Burns & McDonnell) was retained by the City of Great Falls, Montana (City) after submitting a proposal to provide an organizational and financial analysis (Study) of Electric City Power (ECP). The proposal was prepared in response to the City's "Request for Proposals for Energy Consultant", dated April 27, 2009. This report presents the results of this Study which was initiated in August, 2009. This section addresses the purpose of the Study, a historical background of ECP and an overview of the Study methodology.

1.1 PURPOSE OF STUDY

The purpose of this Study as stated and identified in the Burns & McDonnell proposal is to provide: 1) an assessment of the ECP organization and existing operations, 2) an assessment of the current and anticipated future ECP financial situation, 3) an outline of key benefits and key risks relative to the continued existence of ECP, and 4) a listing of key recommendations prioritized by importance and timing.

1.2 BACKGROUND

Prior to June 2003 many residential, commercial, and industrial electric customers within the City received their power from NorthWestern Energy (NWE). In June 2003 a decision was made by NWE's marketing affiliate to breach its supply contract with the Montana League of Cities and Towns (MLCT). The City had been purchasing long-term energy supplies from other suppliers for several years. During that period the overall contract price of energy paid was lower than the NWE default price. MLCT acting as an agent for cities and towns in Montana engaged the services of outside consultants to analyze bids received in terms of pricing and compare to NWE. The result of this analysis showed that the rate from the MLCT study was $33.11/MWh versus $33.80/MWh for NWE. (It should be pointed out that just four years later on June 30, 2007 the NWE default rate had increased to $56.63/MWh, a 68% increase).

Based on past experience and the immediate rate impact at the time of NWE's cancellation, the City determined that its electric energy future would best be served by seeking alternative supply

sources that could replace reliance on NWE. Thus, driven primarily by the need to secure reliable electric power, the City, on August 29, 2003, became a member of Southern Montana Electric Generation & Transmission Cooperative (SMEC). This membership allowed the City to purchase electricity for resale from SMEC. On October 7, 2003, the City passed Ordinance 2861 which allowed the City: 1) to construct, operate, or maintain an electric utility to be known as "Electric City Power", and 2) to market and provide electric services to customers within and/or outside the boundaries of the "City of Great Falls". On November 1, 2005, the City passed Ordinance 2925 which created Electric City Power, Inc. (ECP), a non-profit entity designed to own, operate, and take all actions necessary or desirable in connection with the municipal electric utility of the City. As outlined in this ordinance, the following are the highlights describing the City's controls over ECP:

- ECP cannot issue or incur any bonds, notes, or other evidences of indebtedness without the prior approval of the City Commission.
- ECP does not have any power to bind or create obligations for the City.
- All rates and charges and any rules of operation recommended by the Board of Directors of ECP must be approved by the City Commission.
- ECP must be operated as a nonprofit corporation. No part of the income of ECP may benefit anyone and no party is entitled to share in the distribution of any assets of ECP.
- The City Commission appoints ECP's Directors of the Board.

Effective on October 2, 2007, the City and SMEC entered into a wholesale electric power contract which expires December 31, 2048. This power supply contract does not require the City or ECP to participate as owners in the Highwood Generating Station (HGS). However, the contract does specify (reflect) the City's desire to be an equity participant in HGS if it wishes to participate in SMEC's efforts to secure financing for the construction of HGS. As part of its contract with SMEC, the City did pay for some of the initial development cost of HGS by obtaining a loan from First Interstate Bank. The amount of this loan was $1,400,000. The City also incurred debt issuance costs of approximately $5,000 that needed to be paid in the future.

Since the passage of Ordinances 2861 and 2925, ECP has added addendums to the SMEC contract to purchase multiple blocks of electricity at specified rates per block. These blocks are summarized in the following table:

Table 1.1 ECP Power Block Purchases from SMEC

	Amount (MW)	Price	Timing
Block 1	5 MW	$41.70/MWh (1)	through 12/31/2008
Block 2	8-10 MW	$44.15/MWh	through 12/31/2008
Block 3	7 MW	$52.80/MWh	through 12/31/2008

Beginning in early 2009 ECP's rates were no longer tied directly to individual contract purchases. ECP's rates are transitioning to a blended rate on par with the distribution cooperative member systems of SMEC. This is a significant advantage since there is larger quantities of electricity which is spread over a larger pools of users. This will result in a lower cost of electricity to ECP due to a smoothing of the hourly consumption patterns for all SMEC members. This smoothing results in better scheduling and provides greater competitive advantage to all SMEC members when negotiating long-term contracts. These larger block purchases (in excess of 125 MWh) will result in lower costs than the block purchases (20 MW or less) that ECP contracted for earlier (see table above).

On behalf of the City, SMEC is able to resell on the open market any electricity that the City does not use out of the original purchase blocks. The City also has to purchase electricity on the open market through SMEC if its customers use more than the purchased blocks. The City receives a credit for any electric power resold to the market and a debit for any additional electric power purchased from the market. The combined result of the additional purchases and sales is called "net imbalances."

As part of ECP's contract with SMEC and included in the price for Block 1 is a water credit of $5.70 / MWh for water to be used during the construction and operation of HGS. This water service agreement between the ECP and SMEC was entered into on March 15, 2005. The City

has water rights and water right reservations in the Missouri River for which there is actual water subject to appropriation. Given these water rights and reservations, the City agreed to make water available to SMEC in quantities necessary for operation of the HGS. This water credit accrued until the end of the contract on December 31, 2008 and today totals approximately $1.2 Million. During the anticipated construction and operation of HGS , SMEC will use the accrued water credits to pay for use of the City's water. Once the water credit is used up, HGS will then pay cash for use of the City's water. If HGS does not commence operation, the ECP will be required to pay SMEC for the unused water credits. As of this Report, it has not yet been established how ECP or the City would repay SMEC for unused water credits.

1.3 STUDY METHODOLOGY

The first step in the Study was to review all relevant information and data relevant to ECP and its current and past operations. This included the following:

- Reports related to ECP's past financial performance
- ECP's current energy and capacity contracts
- All enabling ordinances, policies, and regulations
- Membership agreement with SMEC
- ECP's assignment and assumption agreement
- Governing Montana state laws

In addition, contracts with suppliers and current customers as well as correspondence and meeting minutes were made available. Burns & McDonnell also obtained inputs and perceptions from interested parties during a public meeting held in Great Falls on August 12, 2009. This meeting was open to any and all concerned citizens. Interviews were also conducted by Burns & McDonnell with the following critical stakeholders:

- Current City management
- Past City management
- ECP Board Members
- Several of the largest current customers of ECP

- All current City Commissioners
- Chairman and staff of Montana Public Service Commission
- SMEC management
- Concerned citizens

Once the data acquisition phase was completed, Burns & McDonnell performed an assessment of available alternatives and options regarding the future of ECP. These scenarios and any assumptions presented herein were based in part upon the information gathered through interviews and the public meeting as well as Burns & McDonnell's professional experience derived from other assignments. Burns & McDonnell's study methodology also included a assessment of risk and a prioritization of recommendations. These recommendations are presented in Section 5.0 of this Report.

Information provided by the City, ECP, and all parties was used by Burns & McDonnell to make certain assumptions with respect to conditions which may exist in the future. While Burns & McDonnell believes the assumptions made are reasonable for the purposes of this Report, it makes no representation that the conditions assumed will, in fact, occur. While Burns & McDonnell has no reason to believe that the information provided by other parties, and on which it has relied, is inaccurate in any material respect, Burns & McDonnell has utilized industry standards and experience in the industry to verifiy information and data utilized.

1.4 ORGANIZATION OF THE REPORT

This Report is organized into several separate sections. These individual sections are listed below along with a brief description of their contents:

Section 1.0 – Introduction and Background: A description of the Purpose of the Study, Background Information, and the Study Methodology.

Section 2.0 – Organizational Assessment of ECP: Sections containing discussions on ECP staffing, ECP's customer base, Right to Know Provisions, and SMEC.

Section 3.0 – Financial Assessment of ECP: A discussion of the production cost analysis in relation to the Base Case and several sensitivity scenarios.

Section 4.0 – Benefits and Risk Analysis: A summary of the Benefits of Continued Operation of ECP (Section 4.1), Benefits Regardless of the Disposition of ECP (Section 4.2), and Key Risks of Continued Operations of ECP (Section 4.3), and Key Risks Regardless of the Disposition of ECP (Section 4.4).

Section 5.0 – Recommendations: A listing of short term and long term recommendations for future action.

SECTION 2.0

ORGANIZATIONAL ASSESSMENT OF ECP

2.0 ORGANIZATIONAL ASSESSMENT OF ECP

ECP is a corporate entity that is owned by the City and is engaged in the sale of electric power, at retail, to certain key customer accounts in the Great Falls area. Neither the City nor ECP has a certified franchise area to provide retail electric service. ECP operates as a licensed competitive electricity supplier under Montana's electric industry restructuring and customer choice law. Except for those customers served by ECP, the area in and around Great Falls is served by NWE. In performing its organization assessment of ECP, Burns & McDonnell recognized a number of diverse and critical issues needed to be addressed. Listed below are key areas of focus:

- ECP Staffing (Section 2.1)
- ECP Customer Base (Section 2.2)
- ECP Customer Service (Section 2.3)
- ECP Power Supply (Section 2.4)
- Right to Know Provisions (Section 2.5)

2.1 ECP STAFFING

At the present time, ECP itself has no employees. ECP's policies and directives are developed by a five-member Commission who are appointed by the City Commissioners. ECP business activities such as invoicing its customers and providing payments to suppliers and vendors has been accomplished in the past and is currently being accomplished by utilizing City employees such as the City Manager, the Fiscal Services Director, the City Utility Manager, and the City Attorney. The City Manager or his designee, often the Fiscal Services Director, attends the monthly SMEC Board Meeting in Billings. Based on the level of activities required in the immediate future, Burns & McDonnell has a recommendation related to staffing outlined in Section 5.0 of this report.

2.2 ECP CUSTOMER BASE

As mentioned above, ECP currently provides electric service to a number of key accounts under contract for sales of electric power. Table 2.1 identifies these customers which are listed in order of their energy usage in the month of January 2009.

Table 2.1 ECP Customer Listing (by Energy Usage)

Customer Name	Monthly Energy Usage Jan.2009
1. Montana Refining Company	2,676,258 kWh
2. Benefits Health Care	2,053,482 kWh
3. Barretts Materials	2,040.435 kWh
4. General Mills	1,690,881 kWh
5. City of Great Falls	1,052,236 kWh
6. Great Falls Public Schools	1,025,209 kWh
7. Montana Air National Guard	506,824 kWh
8. Veolia Water North America	459,386 kWh
9. Southern Foods Group	448,936 kWh
10. D.A. Davidson and Company	259,681 kWh
11. Great Falls Housing Authority	236, 591 kWh
12. Meadowgold	219, 892 kWh
13. Pacific Steel & Recycling	176, 958 kWh
14. Great Falls Airport Authority	166, 955 kWh
15. McLaughlin Research	124, 800 kWh
16. Pilot Program	115, 493 kWh
17. Federal Express	99,241 kWh
18. Lumber Yard Supply	46,825 kWh

Each of the above listed customers has a separate electric service contract with ECP. While the specific terms of particular contracts may differ slightly from other contracts, the basic terms and conditions of ECP/customer contracts is as follows:

- Full requirements – quantities of electricity purchased shall be the full amount that is required for the entire customer's operations.
- Load forecasts – each year customer provide updates to projected average and peak load requirements during the next year.
- No resale – customer cannot sell or transfer any of the electricity delivered from ECP.

2.3 ECP CUSTOMER SERVICE

As part of the scope of this project, Burns & McDonnell interviewed personnel from many of the ECP customers listed above. Executive management and senior personnel familiar with ECP were the typical subjects of customer interviews. Following is a summary-level of the comments received from these interviews:

- Almost all customers realized lower energy bills utilizing ECP than if they had contracted with NWE for their supply of electricity.
- Customers have found ECP to be responsive and professional in all contract negotiations, billing questions, and business dealings in general.
- Customers have expressed that their overall experience with ECP, including customer service and responsiveness, has exceeded expectations.
- Customers have stated that as long as ECP remains cost competitive, they would prefer to renew their contracts with ECP in 2011 or whenever their current contract expires.

ECP has experienced no delinquent payments from any of its customers since operations began. However, each month imbalances, resulting from sales to ECP customers in excess of the amount purchased from SMEC or from sales to ECP customers less than the amount purchased from SMEC, must be taken into account. Each month, ECP receives a credit for any excess power sold into the open market and a debit for additional power purchases from the open market. The combined result of these transactions is known as "net imbalances". Net imbalance transactions complicate ECP financial reporting because ECP is not informed for several weeks after the sale what the actual price was for electricity. Consequently, ECP as a practical matter records the current month's electricity purchase and then records the net imbalances later when they are informed of the actual value purchased and amounts resold. In fact, there is always a lag

time of six to eight weeks between time electricity bills are payable to SMEC and when the electricity revenues are received for ECP customers. This lag in net imbalance reconcilition mirrors the settlement of imbalances as experienced by SMEC.

2.4 ECP POWER SUPPLY

2.4.1 Background

As mentioned earlier, the City and Southern Montana Electric Generation and Transmission Cooperative (SMEC) entered into a wholesale power supply contract which expires December 31, 2048. This is a full requirements contract that provides 100% of the electric capacity and energy that ECP sells to its customers. Due to the length of this contract and its importance to the future financial viability of ECP, Burns & McDonnell considered it essential that a due diligence review of SMEC's viability and operational and strategic plans for the future be evaluated.

Headquartered in Billings, SMEC is made up of five former electric distribution cooperative members of Central Montana Electric Cooperative: 1) Beartooth Electric Cooperative (headquartered in Red Lodge), 2) Fergus Electric Cooperative (Lewistown, MT), 3) Mid-Yellowstone Electric Cooperative (Hysham, MT), 4) Tongue River Electric Cooperative (Ashland, MT), and 5) Yellowstone Valley Electric Cooperative (Huntley, MT). Shortly after the formation of SMEC, the City of Great Falls joined the SMEC organization as the sixth member. Today, SMEC's service area encompasses 22 counties in the states of Montana and Wyoming; nearly 58,000 square miles, or about 40% of the total land area of Montana. The six entities mentioned above are projected to have base loads of approximately 205 MW and 904,000 MWh in 2010 (including an allowance for losses and reserves).

Historically, power supply for SMEC's members consisted of hydro allocations from the Western Area Power Administration (WAPA), contract purchases, and since 2001, low-cost power from Bonneville Power Administration (BPA). This energy flows across contracted paths of transmission owned by WAPA, BPA, and NWE to delivery points within the cooperative systems. This energy is then delivered to the members and their consumers through substations, distribution lines, and other related infrastructure. In 2008, PPL Montana provided 75% of cooperative generation, with BPA (15%) and WAPA (10%) providing the balance. The BPA

arrangement has been gradually declining over time. It was approximately 33 MW in 2008, and it will expire entirely by 2011. SMEC's 20 MW contract with WAPA continues until 2020.

Due in part to continued load growth and the eventual loss of the BPA supply, SMEC submitted requests for proposals from power marketers and generators to provide options for replacing the expiring BPA contract. As a result of these efforts, a power supply contract was entered into between PPL Montana and SMEC for output from the Corette coal plant in Billings, Montana. This power supply contract began delivery on July 1, 2009 and will continue through June 30, 2019. This contract is a "take-or-pay" agreement and will deliver a contract specific amount of power in each on-peak hour and a contract specific amount of power each off-peak hour of the day. As part of the agreement, SMEC is required to deliver a letter of credit to PPL Montana in an amount equal to 60 days of the energy charge. As a condition of the agreement the precise terms and conditions of the agreement may not be released to the public under the Montana Trade Act. However, in general terms the agreement will give the member systems a power supply portfolio that is affordable, predictable, and secure. It is the opinion of Burns & McDonnell that this agreement will guarantee SMEC member systems it serves a competitively priced product that will protect the member systems and the customers they serve from market volatility until mid 2019. In addition to price certainty, there are provisions in the agreement addressing carbon taxation and other related matters that could profoundly impact the price of wholesale power in the future. The protective provisions contained in the Power Purchase Agreement are favorable to SMEC. For example there is no exposure to any carbon tax that may be imposed until 2016.

2.4.2 Highwood Generating Station

As initially proposed by SMEC, the Highwood Generating Station (HGS) was to be a 250 MW circulating fluidized bed (CFB) boiler designed to combust Powder River Basin (PRB) coal. PRB coal is among the cheapest fuel in the world with delivered costs estimated to be less than $1.00 / MMBtu. This facility was to be located on SMEC-owned land approximately nine miles east of the City of Great Falls. SMEC actively pursued this CFB plant and an environmental air permit was obtained in 2008.

A 2007 report by the consulting firm of RW Beck showed that the electricity busbar cost resulting from this plant was expected to be highly competitive at $43.40 / MWh in 2010 ($50.90 / MWh at the worst depending on escalation assumptions made at that time). Despite this promise, earlier this year SMEC was forced to stop pursuing the HGS CFB project after the RUS announced that it would not be financing any coal-fired projects in the near future.

As a member of SMEC, and in order to promote a long-term reliable supply of low-cost baseload power, ECP contributed $1.40 Million for a 25% equity share of the HGS CFB facility. However, SMEC stopped pursuing the CFB project early this year, after the RUS announced that it would not finance any coal-fired projects in the near future and they were not able to secure financing from other sources.

As currently planned, the HGS will now be a 120 MW natural gas-fired electric power plant that will be located on same site as the formally planned HGS coal-fired plant. The current HGS project will consist of two-40 MW simple cycle generating units that are expected to be completed by 2011. The HGS will also include a 40 MW combined cycle steam turbine unit slated for commercial operation in 2012. Although no future expansion of generating capacity is needed or planned at this time, the HGS site is large enough to provide SMEC flexibility for expansion to meet member demand growth.

All-in cost estimates for the HGS project at its date of commercial operation (COD) are currently estimated to total approximately $250 Million ($2,100 per kilowatt). Initial electricity busbar costs are currently estimated at average $72 / MWh (nominal $) assuming an average natural gas price of $6.50/MMBtu (nominal $). This value is very close to the latest forecasts from the United States Department of Energy, Energy Information Administration (EIA) and the New York Merchantile Exchange (NYMEX) futures. While forecasting energy commodities is a tricky business, Burns & McDonnell concurs with these forecasts and currently incorporates them into all planning-related activities for its clients.

Only four of SMEC's cooperative members are participating in HGS. Each of them has signed an amended power sales contract with SMEC that extends to 2048. Yellowstone Valley Electric Cooperative (Yellowstone) and ECP have both opted not to participate in new HGS natural gas-

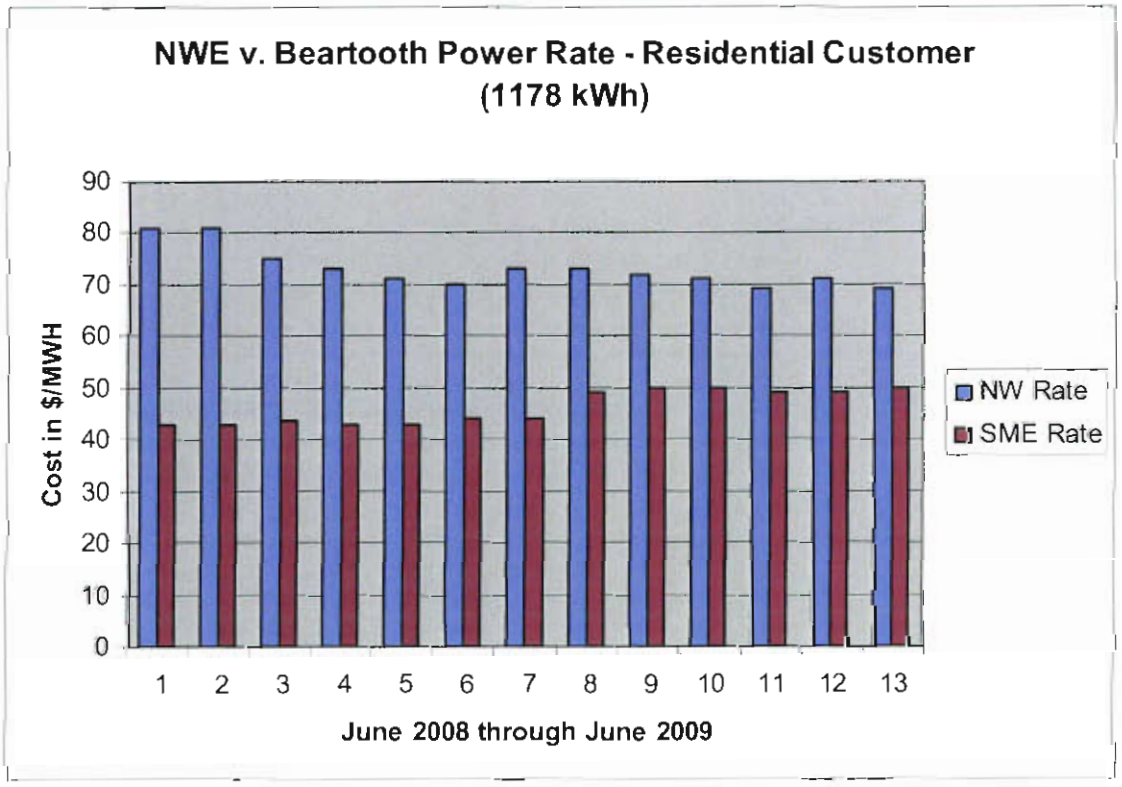
fired generating plant. Also, Yellowstone is now contesting its contract with SMEC and has filed suit to terminate that contract. Nevertheless, SMEC is obligated to serve Yellowstone under an all-requirements contract that expires in 2030.

SMEC received significant criticism for pursuing the CFB option. However, it is the opinion of Burns & McDonnell that, particularly at that time when power supply options weren't at risk of a carbon tax or cap-and-trade program, it was the right direction. This demonstrates prudent decision-making on behalf of SMEC based on providing the least expensive cost of energy for its members.

2.4.3 Outlook for SMEC

SMEC has been a competitive energy supplier with respect other energy providers in the past. As demonstrated in Table 2.2, for many customers including those of ECP, electricity rates from SMEC have shown to be less than those provided by NWE:

Table 2.2 SMEC / NWE Rates Comparison



While the past is no indication of what may happen in the future, it is a demonstration that SMEC is a viable "player" and with continued success will provide ECP customers with a needed competitive and possibly cheaper option for energy into the future.

With respect to HGS, Burns & McDonnell believes that a natural gas-fueled option is the least cost firm energy option available to SMEC and its customers at this time. We expect SMEC rates to increase by 2012, as the new gas-fired unit replaces lower-cost resources, particularly the BPA contract. However, SMEC's relative competitive position will not necessarily decline, as the utility industry in general is facing rising costs. As an example, NWE has recently received approval of a 200 MW, $206 million gas-fired power plant near Anaconda. Once added to rate base, this new plant, as well as the costs of Coalstrip will result in keeping SMEC a competitive electric power provider. During the next couple of years, Burns & McDonnell would expect SMEC to develop commodity risk management strategies to mitigate the increased risk of obtaining fuel supplies and operating the HGS plant. Burns & McDonnell expects HGS to be among the lowest cost options available for commercial operation in 2011-2012 probably competively-price energy for the life of the plant. HGS will be the first plant that SMEC will own and operate.

2.5 RIGHT-TO-KNOW PROVISIONS

An on-going problem that has existed for some time is related to the right-to-know laws that City officials are obligated to follow. These laws, along with the City's attendance at SMEC Board meetings and participation in HGS, have created a dilemma for the City as to how the City can keep its constituents informed while protecting SMEC's trade secrets. It is understood that on many topics and specifically those issues related to participation in HGS, SMEC, as a private corporation, must demand confidentiality in order to maintain a competitive edge in its business of providing low-cost energy.

Since the City has decided not to join the separate development corporation formed by four of the SMEC members to construct HGS, there should not be as much of a need for SMEC to share proprietary information with the City. As a result, it is the opinion of Burns & McDonnell that the City's right-to-know concerns in the future can be satisfied by addressing the following

issues, both of which have recommendations outlined in Section 5.0: 1) future involvement with HGS and 2) interface / reporting structure with SMEC.

SECTION 3.0

FINANCIAL ASSESSMENT OF ECP

3.0 FINANCIAL ASSESSMENT OF ECP

Burns & McDonnell has evaluated several past years of ECP financial reports as well as projections for the future until the existing contracts expire, which, for most customers is June, 2011. Financial results for ECP can be divided into five distinct areas: 1) operating results, 2) long-term accounts payable, 3) long-term notes payable, 4) advances from other funds, and 5) other accounts payable. This section also examines the financial impacts of different ECP liquidation scenarios.

3.1 OPERATING RESULTS

As discussed in Section 1.1, if ECP customers require and purchase more energy than is available from SMEC, ECP is obligated to purchase the additional requirements on the open electric power market. Similarly, if ECP customers purchase less energy than that provided from SMEC, ECP can sell the excess on the open market which benefits ECP's bottom line. The combined result of all transactions associated with additional purchases and sales is called "net imbalances". Unfortunately, there is typically a lag time of six to eight weeks between when electricity bills are payable to SMEC and when the electricity revenues are received from ECP customers. The timing of these net imbalances have caused ECP at times in the past to borrow money from other City funds. The lag in net imbalance reconciliation experienced by ECP is a pass through of the imbalance settlement lag experienced by SMEC.

Table 3.1 on the following page presents a summary of the ECP Sales and Revenues since their inception in 2005. The values presented are on a fiscal year basis. ECP's fiscal year begins on July 1, so fiscal year 2009, for example, runs from July 1, 2008 through June 30, 2009. As shown, during that five-year period the average capacity in Megawatts has increased over three-fold and energy sales (MWh) has multiplied over five-times in just a five year period.

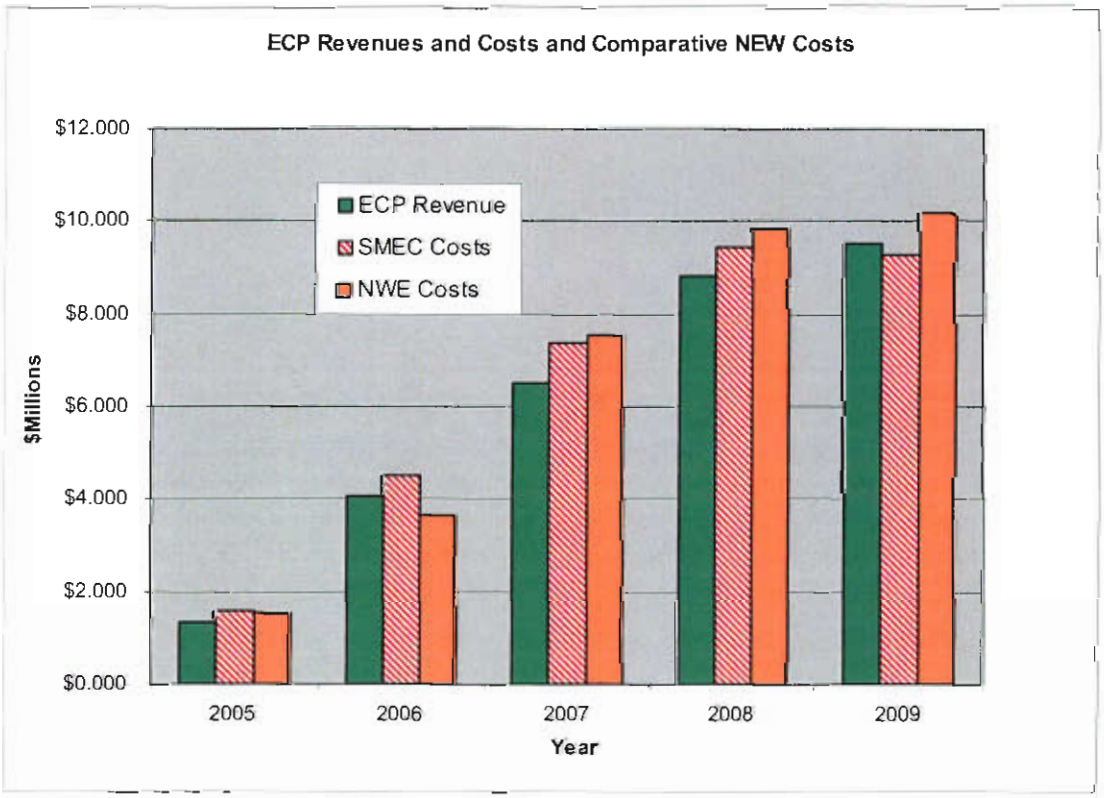
The last three columns of Table 3.1 show revenues and costs from ECP's electricity business on an annual basis. ECP revenues from the sale of electricity to its customers are shown in the fouth column of the table. As can be seen, ECP revenues have increased from $1.306 million in 2005 to $9.504 million in 2009. The next column, SMEC Costs, show what ECP paid for power

purchases from SMEC. The last column, NWE costs, shows what ECP customers would have paid for electric energy if NWE had been its electricity provider. Figure 3.1 presents the information of Table 3.1 in graphical format.

Table 3.1 ECP Sales and Revenues (Actual in $Millions)

	Fiscal Year	ECP Sales		Revenues	Costs	
		Avg. MW	MWh	ECP	SMEC	NW
Actual	2005	9.1	29,900	$1.306	$1.577	$1.545
	2006	15.7	81,184	$4.072	$4.503	$3.661
	2007	21.5	125,370	$6.486	$7.368	$7.547
	2008	28.0	161,210	$8.808	$9.414	$9.842
	2009	28.8	163,028	$9.497	$9.285	$10.182
			TOTAL ($Millions)	$30.169	$32.147	$32.777

Figure 3.1 ECP Sales and Revenues (Actual in $ Millions)



Conclusions that can be reached from the information contained in Table 3.1 and Figure 3.1 are as follows:

- In the past five years (Fiscal years 2005-2009), ECP payments to SMEC have totaled $1.978 Million more than the revenues received from its customers. However, in fiscal year 2009 that trend reversed and ECP for the first time showed a positive cash flow by collecting more revenues from its customers than the amount paid to SMEC for power purchases.

- ECP customers, over the five year period, paid $2.608 Million less for their electricity purchases from ECP compared to what they would have paid if NWE had been their electricity provider. In the last full fiscal year (2009) alone, ECP customers saved $685,000 relative to NWE.

- There is an observable trend that shows SMEC's cost of electricity, once higher than NWE's, has now become lower. If this trend continues into the future it will provide more options for quicker and more significant reductions of current ECP financial obligations.

Table 3.2 below shows the forecast values for ECP revenues and SMEC costs for the next two years.

Table 3.2 ECP Sales and Revenues (Forecast in $Millions)

			($Millions)		($Millions)	
	Fiscal Year	MWh	SMEC Cost	ECP Rev	SMEC Cost	ECP w/10%
Forecast	2010 (1)	169,270	$9.693	$10.008	$9.693	$10.730
	2011	169,834	$10.193	$10.102	$10.193	$11.107
	TOTAL ($Millions)		$19.886	$20.110	$19.886	$21.837

(1) Three months of actuals, 9 months of forecast

With current rates, ECP is forecast to generate $224,000 in profits and with a 10% rate increase will generate $1,951,000 in profits. While ECP, by ordinance, is not allowed to be a profit-making entity these amounts can be used to reduce existing debts and liabilities.

3.2 LONG-TERM ACCOUNTS PAYABLE (WATER CREDIT)

As discussed above in Section 1.2, the City entered into a water agreement with SMEC on March 15, 2005. Since the City has water rights and right reservations in the Missouri River for which there is actual water subject to appropriation, the City agreed to make water available to SMEC in quantities necessary for operation of the HGS. This water credit accrued as a credit on bills payable to SMEC until the end of the agreement on December 31, 2008. Today accrued water credits total approximately $1.2 Million. During the construction and operation of HGS, SMEC intends to use this accrued credit to pay for use of the City's water. Once that water credit is used up, HGS will then pay cash for use of the City's water. If HGS does not commence operation, the ECP will need to repay SMEC for the unused water credit. It has not been established how ECP or the City would pay this money back if the HGS is not constructed.

3.3 LONG TERM NOTES PAYABLE (FIRST INTERSTATE BANK LOAN)

This loan, with a current balance of $1,431,491, is the result of the City's original investment in the HGS coal-fired power plant. This original investment resulted in the City having an ownership share of HGS. The City has since decided not to provide further investment for HGS and this loan will eventually be paid off in full. As the HGS project proceeds and SMEC finalizes equity participation from other owners, the City's ownership percentage of HGS will change. It is Burns & McDonnell's current assessment, based on information received from the City, that the City's ownership share of the on-going HGS project will range from 3.5% to 5.0%.

In order to determine the value of ownership of this asset, Burns & McDonnell conducted a financial analysis based on the price of energy output from HGS. Burns & McDonnell believes it to be reasonable to assume that electricity delivered from this natural gas-fired facility will be less expensive than electricity purchased from the open market by $0.01 to $0.02/kWh ($10 to $20/MWh). Based on these assumed savings and the expected output from the facility (120 MW) and using an annual discount rate of 8%, one can calculate a Net Present Value (NPV) for

thirty (30) years of HGS ownership. Table 3.3 below shows NPV results for a range of plant capacity factors and ownership percentages:

Table 3.3 Net Present Value of Investment in Highwood Generating Station

30 yr NPV ($Millions)	Ownership = 3.5% Savings		Ownership = 5.0% Savings	
Capacity Factor	$.01/kWh	$.02/kWh	$.01/kWh	$.02/kWh
40%	$1.48 M	$2.96 M	$2.11 M	$4.22 M
50%	$1.85 M	$3.70 M	$2.64 M	$5.28 M
60%	$2.22 M	$4.44 M	$3.17 M	$6.34 M
70%	$2.59 M	$5.18 M	$3.70 M	$7.39 M

SMEC's current load factor is approximately 65% and they plan on operating the HGS plant to supply member loads. Therefore, an assumed long-term capacity factor for HGS of between 60% and 70% is considered reasonable. Given this assumption, the City's investment of $1.4 Million in HGS is worth between $2.22 Million and $7.39 Million.

Another way of evaluating the financials of the HGS investment is to examine it from the standpoint of Internal Rate of Return (IRR). Similar to Table 3.3, Table 3.4 below shows the results of IRR for the same range of capacity factors and ownership percentages:

Table 3.4 Return on Investment in Highwood Generating Station

Internal Rate of Return	Ownership = 3.5% Savings		Ownership = 5.0% Savings	
Capacity Factor	$.01/kWh	$.02/kWh	$.01/kWh	$.02/kWh
40%	8.5% IRR	16.9% IRR	12.4% IRR	22.9% IRR
50%	10.9% IRR	20.5% IRR	15.3% IRR	27.3% IRR
60%	13.0% IRR	23.8% IRR	18.0% IRR	31.5% IRR
70%	15.0% IRR	26.9% IRR	20.5% IRR	35.4% IRR

Again assuming a 60-70% capacity factor, ownership of this HGS faciltiy would be expected to show 8.5% to 35.4% IRR. Investment in HGS is expected to provide good returns and is of value to the City. Suggested recourse of HGS ownership is included in the Recommendations section 5.0.

3.4 ADVANCES FROM OTHER FUNDS (LONG TERM)

This amount, currently about $1,500,000, is from advances from other City funds which use the electricity provided by ECP. This is recognized in the form of a loan from the individual funds to the Electric Utility Fund (EUF) and has been used on an ongoing basis to cover any cash deficit in the EUF.

3.5 DUE OTHER CITY FUNDS (CURRENT)

In addition to the long term advances from other City funds, ECP has also had the need to borrow from other city funds on a month-to-month basis. This amount, varies by month and is paid back as soon as possible.

3.6 OTHER ACCOUNTS PAYABLE

Accounts payable to the Energy Supplier (SMEC) is related to the energy imbalances discussed earlier. Other accounts payable are for the cost of Bonds required for participation in HGS. This amount, approximately $394,000 is scheduled to be expensed and paid off over a twenty-four month period.

3.7 ECP LIQUIDATION SCENARIOS

In order to obtain a clearer picture on the impact of timing on the financial performance of ECP, a number of cases were evaluated with regards to possible liquidation of ECP as an entity. Assumptions inherent in these scenarios are as follows:

- For the cases utilizing rate increases, customer rates are assumed to increase for the remainder of fiscal year 2010 and all of 2011.
- As a conservative assumption, retirement of water credit liabilities for HGS is assumed to begin in fiscal year 2012. Currently, commercial operation of the first phase of HGS is in 2011.
- The cost to purchase renewable energy credits has been included. These amount to 5% ($41,250/yr) today, 10% ($82,500 /yr) beginning in 2010, and 15% ($123,750/yr) beginning in 2015.

- The cost for a staff accountant ($60,000/yr including all benefits) increasing by 3% per year has been included.
- Service charges has been increased by 3% per year.
- For projections 2012 through 2015 a 5% annual rate increase has been utilized for ECP and a 3% per year increase in SMEC's costs (e.g. a 2% margin).
- Revenues to the City for potable water and fire protection related to the operation of HGS have not been included.
- Costs for closure of contract with SMEC for recovery of stranded asset costs (as outlined in Section 5.0 of this report) have not been included.

Results for these ECP liquidation scenarios are shown in Table 3.5. The various columns represent the timing for liquidation ranging from immediate (column 2) to the end of fiscal year 2015 (column 9). Column 3 shows results without a rate increase and Column 4 shows results with a ECP rate increase of 10% beginning as soon as can be implemented. Column 5 shows that it would take a ECP rate increase of 32% to provide enough profitability to have a positive cash position assuming liquidation of ECP in 2011. Columns 6 through 9 show the longer term effects for fiscal years 2012 through 2015.

Examination of Table 3.5 clearly shows the benefits of a ECP rate increase and the positive longer term impacts of not liquidating ECP. Rows 1 and 2 of Table 3.5 are liabilities of the City that will eventually be retired as HGS becomes operational. Since these liabilities are independent of whether ECP is liquidated or not, ECP with the 10% rate increase becomes cash positive beginning in 2012. This then leads to a positive cash flow of over $5 Million by the end of fiscal year 2015.

Table 3.5 Liquidation Scenarios for ECP

	Liquidation Scenario >	(2) FY 2009 Liquidation	(3) FY 2011 Liquidation	(4) FY 2011 Liquidation (10% rate increase)	(5) FY 2011 Liquidation (32% rate increase)	(6) FY 2012 Liquidation (2% margin)*	(7) FY 2013 Liquidation (2% margin)*	(8) FY 2014 Liquidation (2% margin)*	(9) FY 2015 Liquidation (2% margin)*
	ECP Summary of Liabilities								
1	Long-Term Account Payable - Water Credit	$1.186	$1.186	$1.186	$1.186	$0.998	$0.811	$0.623	$0.436
2	Notes Payable - Current and Long Term	$1.431	$1.330	$1.330	$1.330	$1.274	$1.213	$1.149	$1.080
3	Advances from Other Funds (Long-term)	$1.500	$1.500	$1.500	$0.000	$1.500	$0.774	$0.000	$0.000
4	Due Other City Funds (Current)	$1.368	$2.656	$1.073	$0.000	$0.344	$0.000	$0.000	$0.000
5	Accounts Payable - Energy Supplier	$0.791	$0.837	$0.837	$0.837	$0.862	$0.888	$0.915	$0.942
6	Accounts Payable - Other	$0.197	$0.079	$0.079	$0.079	$0.000	$0.000	$0.000	$0.000
	TOTAL	**$6.473**	**$7.588**	**$6.005**	**$3.432**	**$4.978**	**$3.686**	**$2.687**	**$2.458**
	Cash and Receivables	**$1.861**	**$2.576**	**$2.739**	**$4.007**	**$2.854**	**$2.975**	**$3.677**	**$5.460**
	Net Impact	**($4.612)**	**($5.012)**	**($3.266)**	**$0.575**	**($2.124)**	**($0.711)**	**$0.990**	**$3.002**
	Assets adequate to liquidate fund	**no**	**no**	**no**	**yes**	**no**	**no**	**yes**	**yes**

* Subsequent to 10% rate increases for remainder of FY 2010 and all of FY 2011; does not take into account stranded cost settlement with SMEC

SECTION 4.0
BENEFITS AND RISK ANALYSIS

4.0 BENEFITS AND RISK ANALYSIS

As with any complex decision, there are both benefits and risks involved in whatever course of action is taken. The key decision to be evaluated in this Study is the continued operation of ECP. Discussed in this section of the Report are the key benefits and key risks associated with the continued operation of ECP as well as key benefits and risks to the City regardless of the current or eventual disposition of ECP.

4.1 KEY BENEFITS TO CONTINUED OPERATION OF ECP

ECP had previously been licensed by the Montana Public Service Commission as an "electricity supplier" under the Electric Utility Restructuring and Customer Choice Act, Title 69, Chapter 8, Montana Code Annotated (Customer Choice Act) with the authority to provide electricity supply services to certain classes of electricity consumers within the State. Montana House Bill 25, which became effective on October 1, 2007, basically repealed the primary elements of the Customer Choice Act, but preserved existing electricity supply contracts that were in effect prior to October 1, 2007. This Bill 25 also requires that licensed electricity suppliers under the Customer Choice Act provide, and its customers be afforded, fair and open long-term access to transmission and distribution facilities, as determined by the Montana Public Service Commission. Listed below are the key benefits of continued operation of ECP:

- As previously discussed, ECP provides a competitive power supply option for its current customers, without which they would realistically be limited to obtaining electricity from NWE only. As evidenced a few years earlier when NWE's predessor, Montana Power, went bankrupt, having only one energy provider proved to be very risky and expensive.
- ECP does not have to add additional customers to achieve and maintain profitability over the long term.
- Over the past five years, ECP customers paid $2.608 Million less for their electricity purchases from ECP compared to what they would have paid if NWE had been their electricity provider. In the last full fiscal year (2009) alone, ECP customers saved $685,00 relative to NWE.

- In other parts of the United States it has been shown that muncipalities which own and operate their own utilities have significant advantages when it comes to attracting new business, particularly those whose electricity loads account for a higher percentage of bottom-line expenses. ECP provides a means for the City to promote economic development activities and attract new businesses for Great Falls and the surrounding region.
- ECP is currently making money and reducing its indebtedness. Liquidating ECP right now would be approximately $1.4 Million more costly than liquidating in 2011 and $7.6 Million more costly than liquidating in 2015 given that ECP rate increases are implemented (as shown in Table 3.5).
- ECP has a core group of institutional, commercial, and industrial customers who are completely satisfied with ECP service and would want to continue doing business with ECP.
- ECP is a member of SMEC. SMEC has to date shown itself to be a viable entity in producing and/or obtaining competitively priced electricity. Based on SMEC's recent power supply decisions and operating performance, Burns & McDonnell sees no indication that this satisfactory performance will not continue into the future.
- ECP, as one of the few public power entities remaining in Montana, can give its customers a competitive choice in the future. Just having this competitive choice available will serve to apply downward pressure on electricity rates.

4.2 BENEFITS REGARDLESS OF DISPOSITION OF ECP

Listed below in no particular order are the key benefits forthcoming to the City regardless of whether ECP is liquidated or not:

- As HGS is built and becomes operational, the $1.2 Million due to SMEC in water service credits will be eliminated. The estimated annual process water requirements for HGS is 2,350 acre feet per year. This equates to an anticipated revenue from service water of $187,639 per year. This means that the water services credit, assuming a 2012 commercial operation date for HGS, will be paid off in 2018,

- ECP has a right to cost-based power from HGS based on its investment in the cost to develop HGS.
- As HGS is built and becomes operational, potable water and fire protection contracts with the City will become active and provide another revenue source for the City. While potable water revenues would be minimal, the benefit to the City would be that HGS would pay for any service water line extensions which would open up opportunities for other users (and City revenues) between the existing city limits and the HGS facility. Currently, SMEC pays $36,000 per year to have Great Fall Fire Department preparedness. Fire protection protection fees for the coal-fired plant were anticipated to be $283,000. An agreement for the gas-fired facility is yet to be finalized. The likely revenues to the City for fire protection fees will definitely exceed $36,000 per year and be less than $283,000 per year.

4.3 KEY RISKS TO CONTINUED OPERATION OF ECP

Listed below in no particular order are the key risks if ECP continues to operate:

- Given the greater than 5 MW requirement for new ECP customers, it is not clear as to how many, if any, new customers ECP will be able to attract in the future.
- Given the current economic environment, it is uncertain how the recession will affect ECP's customer loads in next two years as well as into the future.
- The current working environment between the City and the Montana regulatory agencies including the Montana Public Service Commission is not favorable as evidenced by the existing lawsuit filed by the City. There is potential that future regulatory actions will force further operating constraints on ECP.
- Over the long term, if SMEC is unable to provide competitive rates for electricity relative to other competitors, ECP could once again be in a deficit situation without further rate increases.

4.4 RISKS REGARDLESS OF THE DISPOSITION OF ECP

Listed below in no particular order are the key risks to the City regardless of whether ECP is liquidated or not:

- If HGS is not built, it is uncertain as to how existing investments made by the City in HGS would be recovered from SMEC. Not developing HGS, is viewed as a small risk and is not to imply that this investment would be lost, but only that it is not clear in what manner this would be recovered.
- In addition, if HGS is never built, ECP will have an obligation to pay SMEC for the unused water credit as discussed in Section 1.2.

SECTION 5.0
RECOMMENDATIONS

5.0 RECOMMENDATIONS

It is Burns & McDonnell's overall recommendation that the City not liquidate ECP and continue supplying ECP customers with electricity on a full requirements basis until the expiration of SMEC's current contracts with PPL in 2019. Prior to 2019 if ECP were to request release from its power purchase contract with SMEC there would need to be an agreement and payment schedule reached regarding the issue of "stranded cost". Stranded cost, in this instance would be the financial obligations that SMEC incurred as a function of the power purchase agreements SMEC put in place to meet ECP's forecasted power needs through 2019. That being said, Burns & McDonnell suggests that this decision be revisited in early 2011 once contract extensions have been settled with ECP's customer base. Following is a detailed list of both short-term (2009-2010) and longer term (2011+) recommendations.

5.1 SHORT-TERM RECOMMENDATIONS (2009-2010)

1) Immediately begin negotiating rate increases with ECP customers. Start with the largest and work toward to the smaller customers. Basis and amount of increase should be done strategically with each particular customer depending on their past rate, savings relative to NWE, length of past service, etc. As discussed in Section 3.4, an immediate 32% rate increase would result in ECP being in a positive cash position by the end of fiscal year 2011. However, Burns & McDonnell feels that this is too large of a one-time increase and could result in the possible loss of some customers. However, an overall increase of 10% among all customers is reasonable and fair to existing customers. A 10% rate adjustment would be a modest increase to the customers based on the savings they have realized during the term of their contract with ECP.

2) In conjunction with item 1) above, also work out preliminary details as to contract extension terms and conditions for beyond June, 2011 when most existing ECP/ECP customer contracts expire. These should entail at least three year terms and whenever possible have rates directly tied to those provided by SMEC to limit the risks of the imbalances and market prices. The contemplated rate adjustments can be determined with a fairly high level of accuracy through 2016.

3) Hire a staff accountant who is 100% allocated to ECP. This does not have to be a senior-level position, however, this new employee should have experience with electricity rates and contract negotiations. This individual, who at the discretion of the City Manager, could report to the Director of City's Fiscal Services Department, will need to "hit the ground running" and become familiar with ECP's customer contracts and contract with SMEC.

4) Maintain ownership in HGS. As outlined in Section 3.4 above, partial ownership of HGS, even at a 3-5% level, is a valuable asset. It is the opinion of Burns & McDonnell that the value of this asset will increase over time and as HGS becomes operational. The City has the right to purchase electricity from the HGS facility at the cost of production plus a reasonable margin. In addition, the City's existing liability to SMEC regarding HGS water rights (currently $1.186 Million) will be gradually eliminated as HGS becomes operational. It is problematic that ECP could sell its interest in HGS as that ownership comes from being a member of SMEC and there will be limitations on their rights to sell its undivided interest to a third party.

5) Regardless of whether ECP's ownership interest in HGS continues at the present time, ECP should not have long-term interests in the details of HGS progress other than how it will impact SMEC's rates to ECP. It is Burns & McDonnell's recommendation that ECP and/or the City no longer attend SMEC's Board meetings. Instead, it is suggested that ECP ask SMEC to, at least on a quarterly basis, provide an updated presentation on the progress of HGS as well as any relevant developments regarding SMEC's overall power supply portfolio. This limited contact approach will enable SMEC to keep any proprietary or intellectual data confidential and will eliminate the possibility of the City or ECP personnel from having to deal with possible right-to-know issues.

6) In the past ECP's financial performance has not been in compliance with Ordinance 2925 which states that ECP: "shall be designed to enable the Corporation to produce revenues at all times sufficient to pay all operating, maintenance, debt service, repair and replacement costs of the Corporation and to provide reserves necessary or desirable for working capital, capital improvements and replacements, and rate stabilization purposes." Vagaries and constant change in the power markets, the overall economy, and general business conditions make it

difficult to predict, particularly, on a longer-term basis the profitability of ECP. For the first several years ECP has been in violation of Ordinance 2925, but now is in compliance. Since Ordinance 2925 does not state any time period for its criteria of "revenues sufficient to pay all ECP expenses", it is basically an ineffective tool for examination and evaluation of ECP's performance. Also, inherent in Ordinance 2925 is the fact that ECP is not supposed to be a profit center either, so it is nearly impossible to operate ECP on a "zero sum" basis every month. Burns & McDonnell recommends that the City consider updating Ordinance 2925 with the following provisions: 1) Every six months, at the end of each calendar year (December 31) and at the end of each fiscal year (June 30), ECP will not only report on its profitability as it currently does, but 2) will provide recommended changes if a loss has occurred, 3) will build a reserve fund with any profits that have occurred, 4) provide for the City Council's approval the needed reserve fund level needed for the next six months, and 5) provide recommendations for expenditures for debt retirement, etc. for any funds in excess of the reserve fund amount.

7) It is the recommendation of Burns & McDonnell that the ECP Board be reduced to three members (3) all serving two year terms and still appointed by the City Commissioners. It would be preferred that all members have experience with electricity rates and contract negotiations. Meetings can be scheduled bi-monthly rather than monthly. In addition to those items listed in item 6) above (i.e. profitability, reserve fund, debt retirement), the responsibility and focus of ECP Board, particularly in the short-term, should be on the status of renewed and restructured ECP customer contracts incorporating rate increases.

5.2 LONG-TERM RECOMMENDATIONS (2011+)

a) In January 2011 review in detail the situation with ECP and determine action items based on the following areas:

   a) Status of negotiations for renewal contracts with ECP customers including the ability to obtain rate increases.

   b) ECP's financial performance during 2009-2010.

   c) ECP's ability to lower or eliminate debt and other financial obligations.

d) SMEC's rates compared to their competitors.

e) Progress of HGS and the City's ownership status in HGS.

b) In June, 2011 make a decision on the continuation of ECP based on the following:

a) Number of newly negotiated contracts with existing ECP customers.

b) Success in obtaining long-term profitability for ECP.

c) Success in elimination of some or all debt and other financial obligations.