RFP Description for Purchase Power Proposals

CITY OF ESCANABA ELECTRIC DEPARTMENT
ESCANABA, MI

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TABLE OF CONTENTS

1.0 Introduction **1**
1.1 Background 1
1.2 Events Leading to PSE Engagement 1

2.0 Scope **2**
2.1 Introduction 2
2.2 Approach 2
2.3 Proposed Task Areas 3

3.0 RFP Description **3**
3.1 Summary 3
3.2 Escanaba Contractual Interconnection to Electrical Grid 4
3.3 Pricing and Delivery Costs in the MISO LMP Market 5
3.4 Proposals Received 7
3.4.1 Summary of Proposals Offered 7
3.4.2 Parties A&B Proposal 7
3.5 MISO Operations and Costs 8
3.6 Network Transmission Costs 10
3.6.1 Summary of Resource Portfolio Proposals from Parties A and B 10
3.6.1.1 AR - All Requirements Purchase 10
3.6.1.2 PR - 3 MW 100% Capacity Factor 10
3.6.1.3 Purchase Needs in Excess of 28 MW (3 MW Baseload plus 25 MW Plant Capacity 11
3.6.1.4 Purchase Peaking and Baseload Amounts per Table 3.1 12
3.6.1.5 Interruptible Power up to 10 MW 12
3.6.2 Initial Comments on Parties A and B Proposals 13
3.6.3 Relationship with Supplier 14
3.7 Party C Proposal 15
3.7.1 Relationship with Supplier 16
3.8 Party D Proposal 16
3.8.1 Relationship with Supplier 17

TABLE OF CONTENTS

3.9 Party E Proposal 17
3.10 Summary 17

4.0 Economic Evaluation 25
4.1 Introduction 25
4.2 Data Setup -- Defining Base Year 25
4.3 Load Forecast 26
4.4 Hourly Dispatch Model 27
4.5 Escanaba Self Generation Alternative Cost Projection 29
4.6 Cost Projection Comparison of All Requirements Contracts to Self Generation 33
4.7 Revenue Projection from Selling Energy to MISO Market 35
4.8 Purchase of 3 MW Block 37
4.9 Conversion to Western Coal 38
4.10 Impact of Carbon Tax 40
4.11 Consideration of Biomass Fuel 41
4.12 Conclusions 42

TABLES

Table 3.1 Summary of Resource Needs 3
Table 3.2 Summary of Purchase Power Products in RFP Response by Party 7
Table 3.3 Summary of Capacity Credit Payments 15

Table 4.1 Load Forecast History 26
Table 4.2 Load Forecast Summary 26
Table 4.3 35
Table 4.4 40

FIGURES

Figure 4.1 - Escanaba Load and Economy Sales 27
Figure 4.2 - Escanaba Generation and Purchases 29
Figure 4.3 - Escanaba Steam Expenses W/out Coal 31
Figure 4.4 - Escanaba Steam Expenses 32
Figure 4.5 - Escanaba Steam Expenses (Stacked Bar Format) 33
Figure 4.6 - Escanaba Projected Cost of Electricity Self Generation Compared to All Requirements Alternatives 34

TABLE OF CONTENTS

Figure 4.7 - LMP Revenue vs. Generation Cost 36
Figure 4 8 - Re-Dispatch Generation Results 37
Figure 4 9 - Escanaba Projected Cost of Electricity Self Generation Compared to 3 MW Purchase Alternatives 38
Figure 4 10 – Comparison of Eastern and Western Coal Costs 39
Figure 4 11 – Comparison of Average costs - Biomass and Eastern Coal 42

EXHIBITS

Exhibit 1 - Request for Proposal

1.0 Introduction

1.0 Introduction

1.1 Background

Escanaba has a long history of providing electricity to its residents through the use of the Escanaba Steam Plant which is fueled by Eastern Coal. A combustion turbine peaking unit is also part of the resource mix, and provides additional capacity for the city for backup, or to provide regional support to the transmission system.

Escanaba currently has an arrangement where UPPCO operates the Escanaba Energy Station, which is a 2 unit station totaling 25 MW, and a combustion turbine with a capacity of 15 MW. Escanaba and UPPCO also have an interconnection agreement that provides a gateway to the electric grid for short-term purchases and sales of energy. PSE created a load forecast and power supply evaluation study in 2003 to establish the basis for future power supply requirements. Escanaba partnered with WPPI to contract for an environmental fatal flaw analysis by RTP Environmental Associates and an engineering feasibility study from Sargent and Lundy which were completed in June 2007. Generation cost estimates from the study led the City of Escanaba to issue a Request for Proposal for purchased power. These proposals need to be evaluated in terms of cost and other issues related to how Escanaba is currently operating in the electric grid.

1.2 Events Leading to PSE Engagement

Once the proposals were received, discussions with PSE led to the proposed scope of work, and also allowed PSE staff to participate in a meeting with WPS/UPPCO to get a better understanding how Escanaba is interconnected to the system. Discussions also resulted in lower future ancillary service charges by promoting the concept of Escanaba providing more of its own ancillary services.

2.0 Scope

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2.1 Introduction

Complex analysis is required to evaluate various types of purchase power proposals while taking into account of the use of the existing facilities. The Escanaba Energy Station and peaking resource need to be given proper value when evaluating the purchase power resources. Proposals include a wide range of products including a block of 100 percent capacity factor, interruptible energy, partial requirements purchases to account for system growth, and a full requirements purchase that does not require the use of the existing generation facilities. Re-powering the existing Escanaba Energy Station to biomass is also a resource alternative. The economic analysis of these options is complex and involves evaluation of the system dispatch and consideration of the uncertainty of underlying forecasts of costs associated with operating generation units, load, and costs of constructing new generation units.

2.2 Approach

In order to provide dispatch analysis related to the purchase power proposals, PSE proposed to use an hourly power production model that will simulate resources being dispatched to serve the Escanaba load. This model requires hourly load data, thermal resource data including heat rates, variable O&M, fuel, forced outages, and scheduled outages. The model also provides a means of rolling up the detail of hourly dispatch calculations and costs into a concise report that will be included in the economic analysis. PSE used Access as the hourly model to perform the hourly dispatch analysis.

Another significant factor in the analysis, which can be considered a common to all proposals, is the expected impact of grid integration costs that are driven by changes in the electric industry. FERC Order 888 and 889 required that the costs of transmission be unbundled into a separate category, and the impacts of transmission must be considered. The Midwest Independent System Operator started what is referred to as the Day 2 energy market on April 1, 2005. Costs associated with interfacing with this market must also be considered. There are also other ancillary costs that must be required in order to interact with the electrical grid. The existing Interconnection Agreement provides the

means for Escanaba to interact with the electric grid, but this agreement is expected to be replaced in the future and these costs and expected operational impacts must be considered in the analysis.

2.3 Proposed Task Areas

PSE is proposing to perform services making use of all previously gathered information and will gather additional information from prospective suppliers as needed. The following tasks are envisioned to be performed for the City of Escanaba:

1. Gather Historic Data.
2. Summarize Proposals.
3. Set up analysis.
4. Perform and Summarize Analysis.
5. Finalize Report

Oral Presentations were made to Tasks 2 and 4 with the final presentation scheduled for December 12, 2007 to a joint meeting of the Electric Advisory Committee and the City Council.

3.0 RFP Description

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3.1 Summary

The City of Escanaba sent out a Request for Proposal (RFP) in June 2007 with a deadline of July 12, 2007. Proposals were sent to the following Parties:

Wisconsin Public Service (WPS);

Upper Peninsula Power Company (UPPCO);

Wisconsin Electric (WE); and.

Wisconsin Public Power Incorporated (WPPI).

The RFP, shown in Exhibit 1, included the following information:

1. Background information on the proposed Escanaba electricity needs.
2. Description of desired term of at least 10 years and preferably longer (30 years), starting in 2010.
3. Request of proposals providing all Escanaba future power needs without the use of the existing Escanaba coal units (All Requirements or AR).
4. Request of proposals assuming continued operation of the existing Escanaba coal units (Partial Requirements or PR).
    a. 3 MW of 100 percent capacity factor baseload power.
    b. Purchase energy needs when load is in excess of 28 MW (based on 3 MW baseload and 25 MW plant capacity).
    d. Purchase baseload and peaking capacity according to the schedule provided in the RFP. Peaking and baseload capacity requirements are defined in Table 3.1 as follows:

Table 3.1
Summary of Resource Needs

	2006	2013	2023	2033	2043
Peaking	7.3	7.6	8.0	8.6	9.3
Baseload	15.3	17.1	18.9	21.6	24.5

    e. Purchase power on the spot market when cost effective (cited as being the intermediate load portion).

5. Request that supply proposals include a utilization discussion of the existing power plant.
6. Request inclusion of a purchase of up to 10 MW interruptible for a maximum of 200 hours per year (cited as starting points for negotiation).
7. Comment that the 15 MW peaking unit can be used as reserve capacity for the supplier.

All PR alternatives that involve using Escanaba generation must have a means of purchasing short-term energy in order to match the Escanaba load requirement and cover for conditions such as generation outages. As an example, a 3 MW 100 percent capacity factor purchase does not provide replacement energy when the Escanaba plant is down for maintenance or forced out of service. Discussion of each proposal will include a section on how this short-term energy purchase is made and how it will be priced.

3.2 Escanaba Contractual Interconnection to Electrical Grid

Until recently, Escanaba and UPPCO were parties to an Interconnection Agreement that was developed before significant changes occurred in the electric utility industry. The agreement included a means of providing replacement power when needed and also to sell any excess power. The following were not included in the earlier agreement:

Network Transmission Service -- Network transmission service is a concept designed by the Federal Energy Regulatory Commission (FERC) that allows customers to pay for transmission service based on load and allows for various generation resources to be used to supply energy to the load across the electrical network. The costing method is designed to reflect and recognize the interconnected nature of the electric system and utilize the transmission system for both local and remote generation. Escanaba has not been paying network transmission service charges based on total load to date.

Ancillary Services -- Ancillary services are a defined group of services required to serve electrical loads. At this point, a utility in charge of a control area is typically the provider of the ancillary services and is required to show the basis for arriving at the ancillary service costs. Services include: MISO Scheduling (Schedule 1); Reactive Supply and Voltage Control (Schedule 2); Regular and Frequency Response (Schedule 3); Operating Reserves Spinning (Schedule 5); and Operating Reserves, Supplemental (Schedule 6). Ancillary

services using the 2006 billing units would total $0.43/kW-month for total charges of $136,424. Recent discussions with WPS narrowed down the scope of ancillary services to Schedule 3, assuming that operating reserves are provided by holding back a share of the generation resources.

New Midwest Independent System Operator (MISO) Energy Market -- The MISO energy market (Day 2 Market) started operation on April 1, 2005 and involves a complex arrangement of gathering information from utilities regarding load and generation, and providing instruction to all parties how to most efficiently generate power. The result of the MISO Day 2 Market is that an hourly price is established on the network. Utilities are effectively buying energy from MISO for load serving and selling energy to MISO from generation resources. This price can be used as a market index in utility-to-utility power transactions, or used to determine the cost in delivering power from one location to another location in the MISO network.

Escanaba and UPPCO recently signed a short-term power sales agreement that allows Escanaba to purchase energy from either the MISO market or another supplier. This agreement defines how Escanaba can purchase energy when needed or sell excess energy when available. Some purchase power alternatives from the RFP rely on purchasing short-term power using MISO market prices. The short-term agreement has a provision to allow Escanaba to purchase energy from the MISO Day 2 Market, including an hourly cost adder to take into account the costs of operating in the market. The agreement also has provisions where Escanaba will pay for a share of the network transmission costs based on the amount of energy purchased at the time of the transmission billing hour. The agreement is set up to allow termination by either party as early as March 1, 2008 and may be replaced by a long-term purchase power agreement.

3.3 Pricing and Delivery Costs in the MISO LMP Market

MISO provides services to over 100 suppliers in 15 states and one Canadian province and coordinates operations across 36 load serving regions called “control areas,” each of which must have a constant balance of load and generation. MISO centrally directs specific operation on

generation units based on bidders in order to increase efficiency of serving load and matching buyers and sellers.

One of the pivotal concepts in the MISO market that allows parties to interact is the concept of the Locational Marginal Price (LMP). The LMP is a price specific to a particular location (Node) in the MISO region. MISO establishes an hourly LMP for over 1,500 Nodes on the MISO system. The LMP establishes a price at each Node, and parties can use this price as a means of buying and selling power. Pricing at each Node can also be used to determine the cost of moving power from one Node to another. This is accomplished by taking the difference in LMP from one Node to another.

In order to gain an understanding how the costs of moving power from one Node to another are determined, it is necessary to understand the components of the LMP. The LMP has three components that help define the nodal costs.

1. The Marginal Energy Component (MEC) is defined as the marginal cost of the generating unit providing the last MW of electricity for the hour. Each Node has the same MEC value.
2. The Marginal Loss Component (MLC) is the component designed to reflect incremental electrical losses for that particular location on the system and is derived by a system impedance of that location and the MEC. Each Node has a unique MLC value.
3. The Marginal Congestion Component (MCC) provides a measure of the ability to deliver power to the Node. If the delivery is constrained due to the lack of transmission capacity or generation outage(s), it results in a higher MCC due to higher dispatch costs.

The MLC and MCC values can be used to determine the costs of moving power from one Node to another on the MISO system. The value may be positive or negative depending on the characteristics of the system.

Differences in the MCC from one Node to another may be covered by using an instrument called a Financial Transmission Right (FTR). FTRs are offered by MISO by utilizing an auction for a season-ahead basis, and not for a longer period. Revenues from the costs of selling the FTR are

balanced with the credits provided during periods of congestion. The value of using an FTR to hedge against MCC related costs of delivery is not included in this analysis.

3.4 Proposals Received

Proposals were received from all four Parties that received the RFP. Some of the proposals were more detailed; one Party that initially did not provide much detail later provided more detailed information. In subsequent discussions, Wolverine Electric Power Cooperative, headquartered in Cadillac, Michigan, indicated an interest in providing a block of 100 percent load factor power. In order to protect the confidentiality of the proposing Parties, names will not be used for discussion purposes; but proposing Parties will be designated as Parties A, B, C, D, and E.

3.4.1 Summary of Proposals Offered

Table 3.2 summarizes the response to the RFP requested product:

Table 3.2
Summary of Purchase Power Products in RFP Response by Party

	Party A	Party B	Party C	Party D	Party E
AR - All Requirements	Yes	Yes	Yes	Yes	No
PR - 3 MW 100% Capacity Factor	Yes	Yes	No	Yes	Yes
PR - Power above 28 MW	Yes	Yes	No	Yes	No
PR - Nominated Purchases	Yes	Yes	No	Yes	Yes
PR - Purchase Economy	No	No	No	No	No
PR - 10 MW Interruptible	Yes	Yes	No	No	No

In addition to these offerings, some Parties also showed an interest in working with Escanaba to convert some or all of the Escanaba coal station to a biomass facility. Many states are implementing a requirement for utilities to have a certain percentage of generation from renewable resources; and converting an existing facility to renewable fuel may be more cost-effective than constructing a new facility.

3.4.2 Parties A&B Proposal

Parties A and B provided a proposal for both full and partial requirements. The proposal also included the following requirements:

Escanaba's total load is subject to MISO network transmission charges. (subsequent to receiving the proposal, Network Service is only required for an All Requirements purchases,).

Escanaba's total load is subject to applicable Ancillary Service Charges based on what Escanaba can provide for itself and what needs to be purchased. For a full requirements purchase, all Ancillary Services need to be purchased. For a scenario where Escanaba is using its own generation to serve load, Escanaba would only need to purchase Schedule 3.

Proposals are for both full requirements and Partial Requirements using a formula-based methodology[1] where FERC Form 1 data for the proposing Party is used to calculate both energy and demand costs. An estimate for the energy and demand charges is used for the current year, and a true-up process is used in the first quarter in the following year to capture differences.

Interruptible power supplied to Escanaba will be available and priced using the MISO Day 2 Market LMP methodology.

Both Parties are interested in working with Escanaba to explore the possibility of converting one of its coal units to biomass.

In the description of products responding to the RFP, proposals for Parties A and B propose a term of 20 years, extended annually after the 20 years until terminated.

3.5 MISO Operations and Costs

Details on the MISO operations include the concept of a Scheduling Agent Fee (SAF), where Escanaba would pay Parties A or B to act on behalf of Escanaba to perform all MISO market activities regarding purchases from the market and offers into the market. The proposal includes a

[1] A formula-based rate is a method of setting a price that is dependent on the report costs by category on the FERC Form 1. This approach is contrasted by a market-based rate where the seller sets the rate based on a price that the seller will find acceptable.

number of complicated formulas for the Day Ahead (DA) and Real Time (RT) market transactions. The SAF is something that would be negotiated as part of any purchase deal and would be in place of Escanaba adding staff for MISO operations and settlements.[2]

Detailed formulas were provided in the proposals showing how MISO settlements are performed, as well as specific customer charges and estimated capacity and energy rates. These are not necessary to discuss at this point and illustrate the complexity of performing MISO operations and settlements. Because energy is delivered to the UPPCO load zone[3], the Parties are proposing that Escanaba would be responsible for the congestion charges for delivery power to Escanaba if the American Transmission Company (ATC) Northern Umbrella transmission project is not completed.

One question in relation to the SAF services related to the load forecasting method is: If Escanaba is paying Parties A or B to create the load forecast, submit the MISO data, and process the settlement data on behalf of Escanaba, is there a mechanism for Party A or B to ensure an accurate forecast? There is a way to separate out the load forecast in the settlement process that maintains a price signal to create an accurate Escanaba load forecast. It does not seem to make sense that Escanaba would have to pay for a forecast and end up being financially responsible for any forecast error.[4]

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[2] Settlements are the process of evaluating the MISO invoices, which is a very complex process due to the number of charges and credits that are designed to reflect the MISO market design.

[3] Escanaba is located in the UPPCO load zone, and this provision of delivering to the UPPCO load zone is common for all proposals.

[4] The DA load forecast is created and load is offered to MISO. If the RT load differs from the DA load, the RT LMP comes into play by either selling the excess (RT load less DA load) or buying energy at the RT LMP when RT load is greater than DA. This part of the settlement can be spun off in order to provide a “price signal” to keep the forecast accurate. It is also possible to have a positive margin due to differences in the DA and RT load.

3.6 Network Transmission Costs

The 2007 cost for MISO network transmission service is $3.07/kW-month. For Escanaba, the total of the 12 monthly peaks (January-December) for 2006 was 317,267 kW[5]. Using the current network service charge of $3.07/kW-month, the 2006 charges would have been $974,036 ($3.07 times 317,267 kW).

Since the time of the original proposal, Parties A and B have agreed to allow purchasing point-to-point transmission for Partial Requirements purchases and not requiring Escanaba to purchase network transmission service as a condition of receiving power.

3.6.1 Summary of Resource Portfolio Proposals from Parties A and B

3.6.1.1 AR - All Requirements Purchase

The assumption in this portfolio is that none of the existing Escanaba generation would be used to supply energy to Escanaba load. All Escanaba load requirements would be supplied by the generation and purchased power resources of Parties A or B. Demand and energy charges are based on the FERC approved formula rate. Parties A and B have offered this same All Requirements service to others in the Upper Peninsula that do not have generation resources. Charges in a formula-based rate include a demand charge that is based on the maximum hourly demand (MW) at the time of the supplier's peak and an energy rate that applies to all MWh purchased.

3.6.1.2 PR - 3 MW 100% Capacity Factor

This Partial Requirements purchase assumes continued operation of the Escanaba generation resources. Pricing for this proposal is based on the formula-based rate. This 3 MW purchase does not include a means to cover short-term energy needs during times of energy shortfalls. The proposal takes this into account by requiring that a deviation

[5] Coincident with Escanaba--not the ATC, where the billing is actually determined on the ATC coincident peak.

penalty or credit[6] be used to cover differences in energy shortfalls or excess. This amounts to purchasing or selling energy in the MISO RT market, rather than allowing the energy to be transacted in the DA market. If an energy shortfall is expected, transacting in the DA market is the best approach for covering the shortfall. **Since the time of the proposal, the Parties have agreed to allow the use of the DA market for expected shortfalls, rather than only the RT market.**

3.6.1.3 Purchase Needs in Excess of 28 MW (3 MW Baseload plus 25 MW Plant Capacity

This is a Partial Requirements purchase that is intended to allow Escanaba to purchase energy that is needed above the 25 MW from plant capacity and the 3 MW 100 percent capacity factor purchase. The proposal suggests using a price sensitive demand bid in MISO and using a demand purchase to firm up the purchase to avoid interruption during a MISO emergency.

A price sensitive demand bid allows a purchasing Party to set a price for a given load level. If the MISO price is higher than the bid price, the purchasing Party will interrupt the load or generate rather than buy energy from MISO. Without getting into more details on how this pricing mechanism is structured, it does not appear that this type of transaction would supply energy above and beyond the 25 MW plus 3 MW of 100 capacity factor purchase; but it is intended to serve the load below the bid price load.

6 MISO Day 2 Market mechanism for making sure that the planned energy schedules are actually delivered.

3.6.1.4 Purchase Peaking and Baseload Amounts per Table 3.1

This is a Partial Requirements purchase and would require Escanaba to quantify the amount of the purchase for a given time period such as monthly or annually. The nomination amounts would be defined by information from Table 3.1. The pricing mechanism proposed for Escanaba to purchases energy would be based on the MISO LMP.

One variation on this alternative is to have Escanaba purchase all energy from the supplying Party (A or B) and sell Escanaba generation resources directly to the MISO market. Escanaba would receive revenue from MISO for all hours where the generation was lower cost than the MISO price. The generation would be operated in a way to provide Escanaba margins for operating the generation, and Escanaba would be purchasing full requirements from the Party at the formula-based rate.

A second variation on this type of proposal would involve Escanaba purchasing All Requirements from the Party and converting one of the coal units to biomass. The other unit would remain as a coal unit and could be sold into the MISO market. The purchasing Party would purchase energy from the biomass unit at a negotiated price. Financing alternatives could also be arranged in working with the proposing Party.

3.6.1.5 Interruptible Power up to 10 MW

The supplying party is defining a product where Escanaba is allowed to take Discretionary Interruptible energy for 600 hours if service was being taken as a full requirements customer.

In order to serve a portion of the Escanaba load as interruptible, the load must be separated into groups or "buckets," each having its own defined load and level of firmness. Levels are defined as Firm, Discretionary Interruptible, and General Interruptible. In any given hour, the levels are filled starting with Firm, then Discretionary and, finally, General Interruptible. Escanaba would set up a defined amount into each bucket and would fill each bucket hourly as defined by the load.

The amount of Discretionary Interruptible would be capped at 15 percent of Firm Load. Generation that is not offered into the MISO market would only be allowed to serve the Discretionary Interruptible. Firm load would be priced using the formula-based rate and would be based on actual energy usage in this category.

Pricing for the Discretionary Interruptible load would be priced at the formula-based rate less an interruptible credit, with $5/kW-month given as an example credit. Hours of interruption in the Discretionary bucket would typically be managed in a way to exhaust the maximum number of hours. Notice must be given for interruption by 4 p.m. of the previous day; and Escanaba would be given the alternative to either provide resources to serve load, interrupt the load, or purchase energy from MISO at the RT MISO price.[7]

Pricing for the General Purchase Interruptible load would be priced at the RT LMP and would be interrupted if MISO called for a system emergency. Escanaba would be responsible for interrupting this amount of load for MISO System emergencies and would be subject to penalties in the event that the load could not be interrupted.

3.6.2 Initial Comments on Parties A and B Proposals

Offerings from Parties A and B involve a number of complex operations, including working

[7] MISO has a price for the DA market and RT market. Prices for the DA market are set based on the projected information and established one day before the day of operation. RT prices are calculated on the day of operation and are based on actual load and generation on the system.

with MISO market operations and working on short-term load forecasting in order to purchase energy. Initially, the proposal required Escanaba to purchase network transmission service which would be an annual cost of nearly a million dollars.

Subsequently, point-to-point transmission service is considered acceptable for Partial Requirements purchases. For utilities serving load on the electrical grid network, network service is used because there are typically many sources of providing electricity, both owned generation and outside purchases.

Point-to-point transmission service would be available for a Partial Requirements purchase. It would result in transmission charges of $3.07/kW-month only for the amount purchased. As an example, if 10 MW of peaking or baseload was purchased, the amount of transmission charges would be 12 months x 10 MW x 3.07/kW = $368,400 for the year. In a situation where Escanaba only needs to purchase 10 MW for the entire year, it would certainly be preferable to pay $368,400 compared to paying nearly $1 million for network service for the entire Escanaba load. If more than 10 MW is needed for times that the plant is out of service, a penalty of an additional 50 percent would be added to the point-to-point transmission service charge for the additional purchase amount.

One of the significant concerns about all options offered by Parties A or B is that there does not appear to be any capacity or energy credit for Escanaba generating units or in having a situation where the units are dispatched in conjunction with the purchased power products. A capacity credit could be given to recognize that there is available generation and could be applied to reduce the demand charges. An energy credit could be used to reduce the energy purchases from the supplier where the generation is used in conjunction with a formula-based Partial Requirements purchase. This lack of credit appears to penalize the economics of the purchase alternative offered by Parties A or B.

3.6.3 Relationship with Supplier

This proposal results in Escanaba purchasing power; but Escanaba is still responsible for staying abreast of current issues regarding transmission, MISO, environmental, and other

areas. The relationship with the supplier could be considered "arms length" and is not a partnership or alliance where interests are aligned.

3.7 Party C Proposal

Party C provided a proposal only for All Requirements service. The proposed term of the contract is 30 years. It is a long-term supplier partnership relationship where Escanaba is purchasing all energy requirements and the supplier is actively looking out for the interests of all customers, including Escanaba.

A key element in the proposal for Party C is that the supplier is requiring that the Escanaba coal unit not be dispatched. This is a significant consideration when it comes to evaluating this supplier.

The supplier is also proposing to provide Escanaba with a peaking unit capacity credit of $1.50/kW-month with an annual escalation of 0.05/kW-month and also provide a payment to Escanaba for O&M and fuel whenever the peaking unit is operated. The 2008 without escalation is $270,000. These payments would escalate over a five-year period as shown in Table 3.3. A new contract would be negotiated after the first five years.

Table 3.3
Summary of Capacity Credit Payments

Year	Estimated Payment
2011	$ 306,000
2012	315,000
2013	324,000
2014	333,000
2015	372,000
Total	$1,650,000.00

The Escanaba peaking unit is currently being used in the MISO market and is expected to operate when economical.

Party C is also proposing to offer a wide range of services in conjunction with the purchased power contract. These include retail rate studies, joint purchasing, financial planning, rate comparisons, regulatory filing, large customer billing services, and economic opportunities assessment.

There are no additional charges for MLC or MCC to deliver the power from Party C to Escanaba. Party C customers are required to contribute a share of a rate stabilization fund designed to cover unforeseen costs resulting in a stable rate. Escanaba would be required to contribute $800,000 to the fund, which is the same as $5/MWh or 0.5¢/kWh for the 2006 sales to customers of 160,000 MWh.

Operation considerations include making arrangement to serve Escanaba in the UPPCO control area. Party C has worked with a number of other customers to bring them into the Party C control area and is expected to work through specific arrangements on how to do this for Escanaba, if needed.

Party C has expressed interest in working with Escanaba to explore the possibility of converting both of the Escanaba coal-fired units to biomass, but the proposed arrangement or credits are not defined at this time.

3.7.1 Relationship with Supplier

Party C is proposing to have a long-term supplier relationship with Escanaba. The interests of Escanaba and Party C are similar in terms of transmission issues, MISO operation, environmental concerns, and other areas. This type of long-term partnership would result in Escanaba being able to focus on the distribution operation of the system. However, this is a double-edged sword; it allows a “sigh” of relief in that Escanaba does not have to stay abreast of these issues, but it also involves a loss of individual sovereignty and flexibility on Escanaba’s part.

3.8 Party D Proposal

Party D has a FERC approved formula-based rate that can be applied as either a Partial Requirements or full requirements purchase. Some customers served by Party D purchase all energy from Party D, while others have generation and purchase Partial Requirements. Capacity credit would not be given for existing generation unless the generation is operated during the time of the monthly peak. Party D is interested in either a partial or full requirements alternative and would also require a fee for performing MISO operations.

Operation considerations include making arrangement to serve Escanaba in the UPPCO control area. Party D is not part of the UPPCO control area, and there would be a need to set up metering and communication facilities to integrate the Escanaba load and generation into the Party D control area. Power received from Party D would be delivered to the Party D load zone, and not to the UPPCO control area. MISO MLC and MCC costs would have to be paid by Escanaba for delivery of power from the Party D control area to the UPPCO control area. These costs must be included when evaluating a purchase from Party D and are currently in the range of $10/MWh.

3.8.1 Relationship with Supplier

This proposal results in Escanaba purchasing power; but Escanaba is still responsible for staying abreast of current issues regarding transmission, MISO, environmental, and other areas. The relationship with the supplier could be considered "arms length" and is not a partnership or alliance where interests are aligned.

3.9 Party E Proposal

Party E is interested in supplying a block of high capacity factor energy that could be integrated with the existing Escanaba resources. MISO operations would need to be performed by Party E and would involve tracking the scheduling of the load, purchases and generation.

Power received from Party E would be delivered to the Party E load zone, and not to the UPPCO control area. MISO MLC and MCC costs would have to be paid by Escanaba for delivery of power from the Party E control area to the UPPCO control area. These costs must be included when evaluating a purchase from Party E.

3.10 Summary

1. Parties A and B have provided a wide range of purchased power options, many of which involve integrating pricing and operations with MISO. Delivery of energy to the UPPCO control area does not involve risk of MLC or MCC charges unless the ATC Northern Umbrella Plan is not completed.
2. Party C is offering a long-term partnership of supplying All Requirements to Escanaba and involves shutting down the Escanaba coal-fired generation facility. Other services offered

to Escanaba with this will result in an improved system and cost savings. MISO operation costs are included in the proposed costs; and all Party C customers pay the same costs, without regard to location on the system (no direct exposure to MLC or MCC charges).

3. Party D is offering a FERC approved formula-based rate that can be applied to either All Requirements or Partial Requirements purchases. Partial requirements operations can be integrated with existing generation facilities, and costs for the formula-based rate would be lower when the generation is operated. Delivery to the UPPCO control area from Party D would involve exposure to MLC and MCC charges.
4. Party E is offering a block of 100 percent capacity factor energy and would be willing to perform MISO operations. MLC and MCC charges would need to be paid from the source control area to the UPPCO control area.

4.0 Economic Evaluation

4.0 Economic Evaluation

4.1 Introduction

Evaluation of purchase power options is comprised of two basic components. The first component is a projection of Escanaba's estimated costs of generating its own electricity (Self Generation Alternative), with the balance coming from the MISO market and selling any excess to the market. The second component involves comparing the Self Generation Alternative to the various purchased power proposals. The All Requirements purchased power alternatives were compared to the Self Generation Alternative in order to determine the comparison of projected costs. Additional analysis involved evaluating Partial Requirements options and the projected revenue from selling generation directly into the MISO market for purchases of generating margins. Proposal information was screened to determine the most attractive offers. Only the most attractive proposals are evaluated in this section. Confidentiality of the proposals is also maintained in this Section, and parties are named Party 1, 2, and 3 without any correlation to Parties A – E in Section 3.

Cost projections in this report are for the power supply related costs of generation and transmission and do not include costs for operating or maintaining the distribution system. Information from this study cannot be directly used to project electricity rates, but need to take distribution costs and other factors into account.

4.2 Data Setup -- Defining Base Year

Hourly load information was gathered for the system load, the steam and combustion turbine generation, and the hourly LMPs. Historic data was gathered from January 1, 2003 through June 30, 2007. After evaluating the information and taking into account that recent improvements to the Upper Peninsula transmission system have resulted in lower congestion and loss values, it was determined that the base year for load and generation is the period from July 1, 2006 through June 30, 2007. This is the period that is used for the load and generation hourly information as well as the LMP data. One exception to this is that the generation data was modified to account for the long outage (middle of May through the end of June in 2007) due to a lightning strike. Data from the previous year during the same time period was substituted in as a proxy for a generation shape.

4.3 Load Forecast

The load forecast, summarized in Table 4.1, shows the forecast history for the period from July 1, 2003 through June 30, 2004 and all the way through the 2006 to 2007 fiscal year. Growth rates for the subsequent years are based on the power supply study that PSE performed in 2003 and are in the range of 1.2 percent a year. The hourly load shape was grown by this percentage into the future and went out into the year 2021. The shape of the generation curve remains the same for all future study years. The LMP price was assumed to escalate at 4 percent a year into the future based on the evaluation of inflation and natural gas prices in the future.

Table 4.1 shows the load forecast history for July 1, 2003 through June 30, 2007; and Table 4.2 shows the load forecast from 2007 through June 30, 2021.

Table 4.1
Load Forecast History

Beginning Year	Ending Year	Energy (kWh)	Annual Peak (kW)	Annual Load Factor
2003	2004	153,523,599.34	29,120.17	60.2%
2004	2005	160,959,272.90	29,582.87	62.1%
2005	2006	162,461,897.41	31,768.66	58.4%
2006	2007	158,432,147.63	31,589.87	57.3%

Table 4.2
Load Forecast Summary

Beginning Year	Ending Year	Energy (kWh)	Annual Peak (kW)
2006	2007	158,432,148	31,590
2007	2008	160,333,333	31,969
2008	2009	162,234,519	32,348
2009	2010	164,135,705	32,727
2010	2011	166,195,323	33,138
2011	2012	168,096,509	33,517
2012	2013	170,156,127	33,928
2013	2014	172,215,744	34,338
2014	2015	174,275,362	34,749
2015	2016	176,334,980	35,160
2016	2017	178,553,030	35,602
2017	2018	180,612,648	36,012
2018	2019	182,830,698	36,455
2019	2020	185,048,748	36,897
2020	2021	187,266,798	37,339

Load projections are the key metric for determining when additional electricity resources are needed above and beyond the existing resources. The capacity of the Steam plant is 25 MW, and the combustion turbine is 15 MW. This provides 40 MW of capacity. From a capacity perspective, a party is required to have 15 percent more generation than the highest peak demand. This results in a maximum allowable peak demand of 34.7 MW with the existing capacity. From the existing load forecast, this ties to the forecast for 2014-2015. Actual load growth will determine the timing of needing new capacity.

4.4 Hourly Dispatch Model

The hourly load and generation and price information was evaluated in an Access model on an hourly basis. The model created an hourly energy balance of generation, purchases, sales and load. Annual values summing up the maximum and sum of all these components were critical in order to determine the billing units for purchasing from other Parties. The hourly dispatch model provides indication as to when there is surplus energy during times with high generation output and low load. Economy sales are projected to be 7,200 MWh or 4.5 percent of the Escanaba load. Sales are projected to decrease to 1.5 percent of load by 2019. Figure 4.1 shows the annual energy for load and economy sales.

It is important to note that the modeling was using an hourly determination of the generation compared to the load (i.e., if generation is greater than load, there are sales) to determine the occurrence of an economy sale. The current interconnection agreement uses a pricing mechanism to determine if a sale is made. These volumes are higher than what has been observed historically and may be an indication of an opportunity to sell more energy from existing resources.

The maximum MW purchased for an hour was compiled on a monthly basis in order to determine the amount of point-to-point transmission that is needed to be purchased. In reality, the maximum purchase hour is based on the system peak providing transmission or power; but for purposes of our analysis, it is not feasible to estimate the time of peak from the purchasing Party.

Steam generation is projected to be just less than 150,000 MWh for the entire study period, which is well over 90 percent of the energy needs for the City. As the Escanaba load grows, there is a need to purchase more energy from another party. Thermal generation provides a lower percentage of the total. Steam generation is projected to provide just over 80 percent of the total in 10 years. There is an increasing dependence on purchase power, increasing from about 10 percent in 2007-2008 to nearly 20 percent, or 31,000 MWh, in 2015-2016. Figure 4.2 shows the projected generation and purchase power energy for the 2006-2007 through 2019-2020 periods.

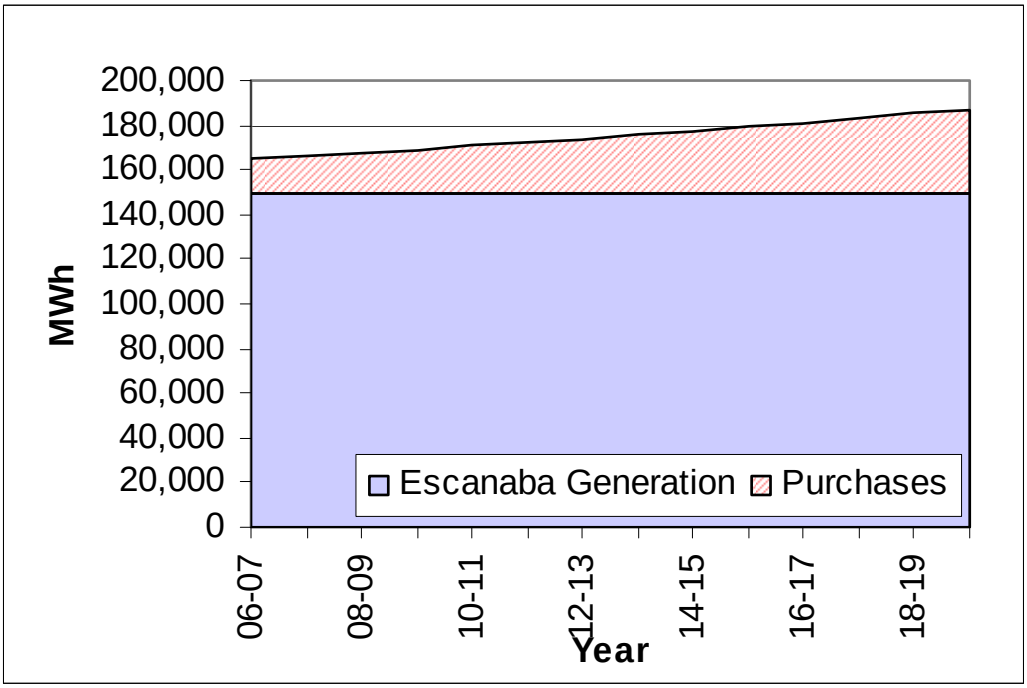

Figure 4.2 - Escanaba Generation and Purchases

It is important to note that the projected purchase volumes can be made from the MISO energy market through the existing UPPCO interconnection agreement without entering into any purchase agreements with other parties.

The capacity amounts for the purchase (annual MW-monthly amounts of purchasing for each of the 12 months) average 10 MW and increase to 12 MW by 2014-2015. Sales are typically due to emergency events calling for the combustion turbine to run, but may be scheduled off the steam unit during times of lower loads. The system was not re-dispatched to optimize sales, and it is expected that there may be additional opportunities to sell that are not reflected in the historic dispatch of the generation units.

4.5 Escanaba Self Generation Alternative Cost Projection

Projecting the Escanaba Self-Generation Alternative was extremely involved and included a projection of various line items from Escanaba's Operating Statement. The analysis is broken down into the main categories of steam expenses, combustion turbine expenses, energy purchases and energy sales. The line items from the steam expenses include operating expenses, coal costs,

administration, maintenance, management fees, dispatching fees, payment to the state, and ash costs. Projections for each of the expense and fee categories involved evaluating historic data, starting from 2003-2004 to 2006-2007 and using contract escalation terms. Projections of the steam expense line items involved evaluating the historic data and determining a trend where possible.

The cost for maintenance was fairly difficult to project because of historic values varying widely over the last four years. The expected amount of maintenance is projected to be $750,000 annually, which is in the range of the historic data. A determination was made to use the value of $1.2 million/year, escalating at 3 percent/year. Ash costs are assumed to be $230,000/year, escalating at 3 percent/year. Overall, the steam expense represents the lion's share of the total cost of generating power. Additional costs for purchases, additional revenues and sales can typically balance out the overall costs. Annual costs end up in the $11.5 to $12.0 M range for the early years of the projection.

Figure 4.3 shows the Steam Expenses by line item for both the history and future.

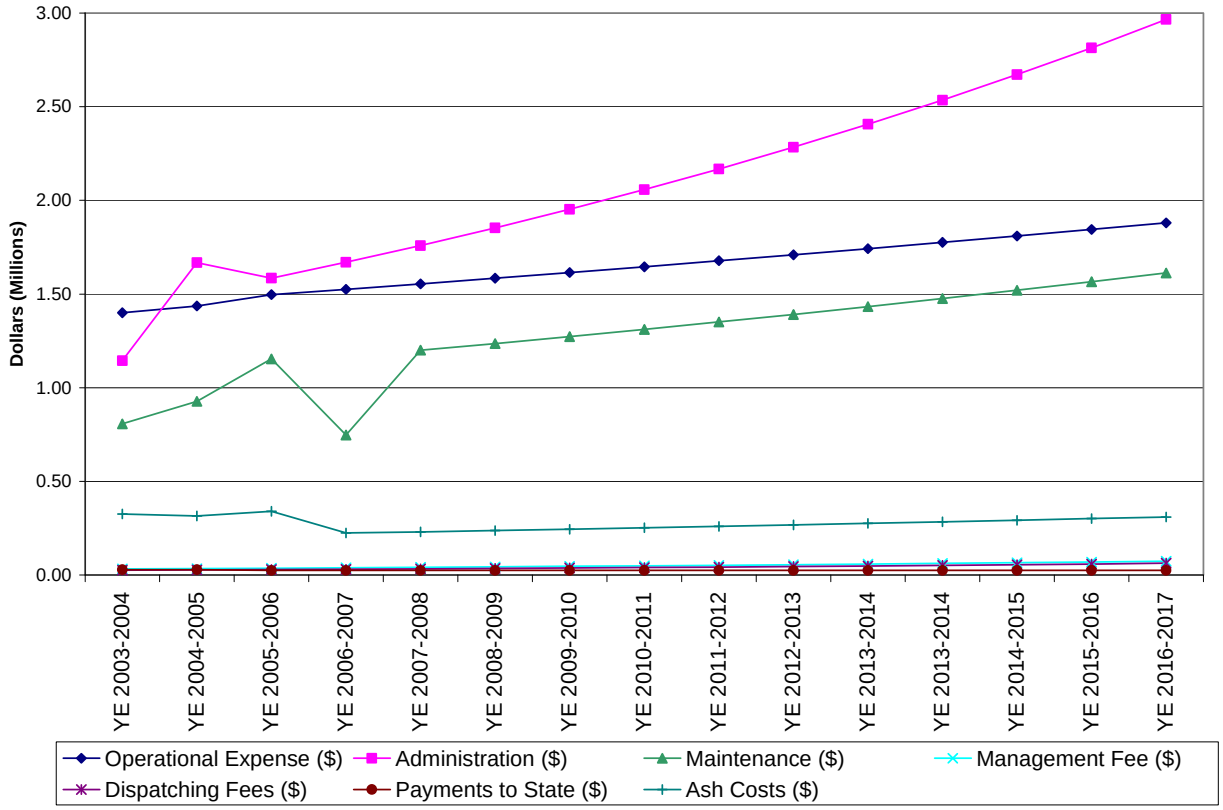

Figure 4.3 - Escanaba Steam Expenses W/out Coal

The projection for coal costs is based on an Annual Energy Outlook (AEO) 2007 value indexed to historic costs that have been seen in delivering the coal to Escanaba. The particular coal costs (without transportation and handling) from the AEO that were used are the medium Appalachian coal cost and the Central Appalachian medium sulfur premium coal cost, provided in real 2005 dollars/short ton. An inflation value of 3 percent was used to convert these costs into nominal dollars. Transportation and handling costs were projected using the 2007-2008 estimated value of $23/ton, and escalating this component of costs by 4 percent into the future. Given the upward pressure in oil prices due to increased global demand, and the correlation of oil prices to coal delivery costs, it appears reasonable to use a 4 percent escalator for the delivery and handling costs.

Overall, the coal costs in dollars/ton are projected to increase by about 3 percent through 2010, and remaining flat through 2012, and then increasing at 3.0-3.5 percent through 2018. Nominal coal costs are projected to be $77.84/ton in 2010-2011 and $88.28/ton by 2018-2019. These increases are extremely high, and are driven by the escalation in the transportation component of the costs. The coal price projection is clearly the main driver in this cost analysis

An alternative coal projection of 4 percent annual escalation has also been developed in order to evaluate a Self Generation Alternative with a higher fuel cost. Figure 4.4 shows the Steam Expenses including Coal, which are over 50 percent of the Total Steam expense.

4.0

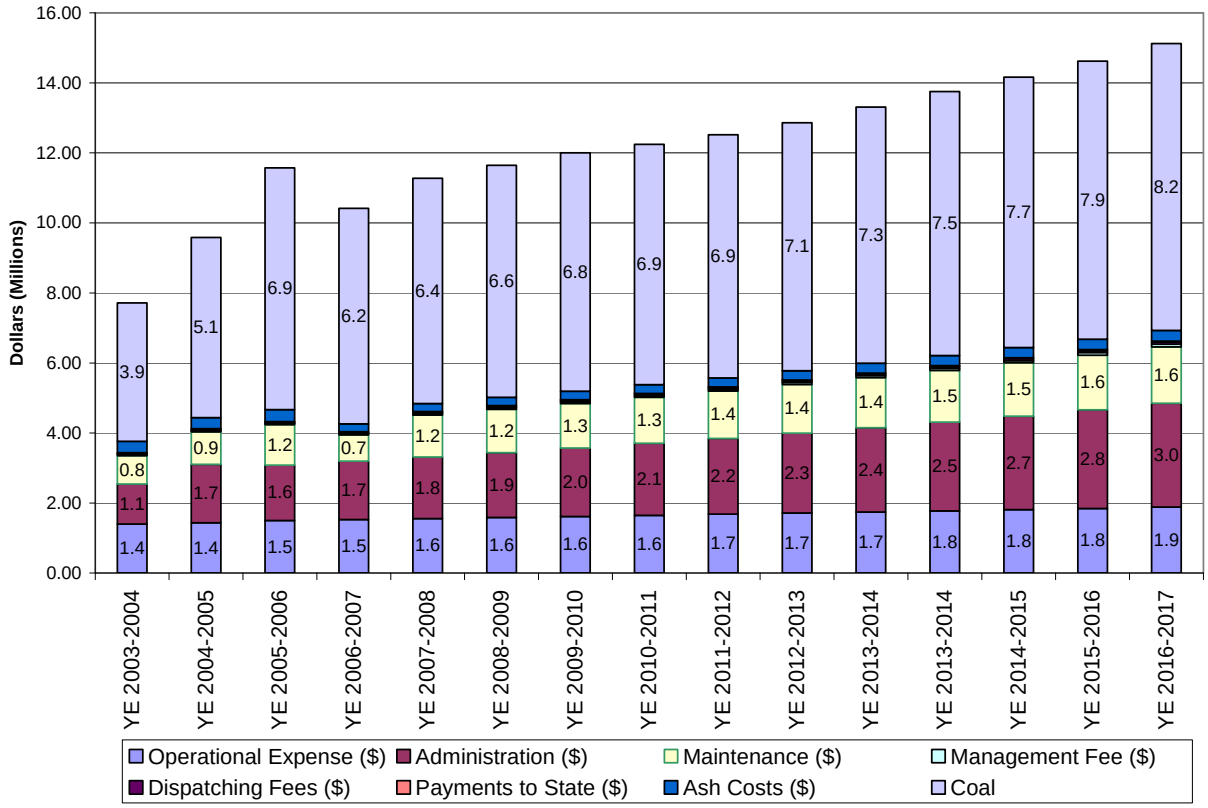

Figure 4.5 - Escanaba Steam Expenses (Stacked Bar Format)

4.6 Cost Projection Comparison of All Requirements Contracts to Self Generation

Annual comparisons of the Self Generation option compared to the All Requirements show that the All Requirements for three Parties interested in providing All Requirements energy are, for the most part, lower cost than the projected cost of Escanaba generating its own electricity. The cost projection for two of the Parties is within 5 percent of the projected cost of Escanaba generating its own electricity. The projection of one of the three Parties is significantly less--something in the range of 8 to 9 percent less cost or $2.6 million a year in reduced costs. Transmission costs for the Self Generation Alternative include the accumulated demand charges for energy purchased during the time of the ATC peak and result in a transmission cost in the range of $400,000/year. The cost for network service transmission is in the range of $970,000/year and is assumed to be required for any all requirement purchase arrangement. One of the All Requirements Parties is not delivering

electricity to the local UPPCO load zone, which involves an estimated additional MLC and MCC of $10/MW/hour.

Figure 4.6 shows a comparison of the annual expenses of the Self Generation Alternative and All Requirements for three Parties proposing to provide resources:

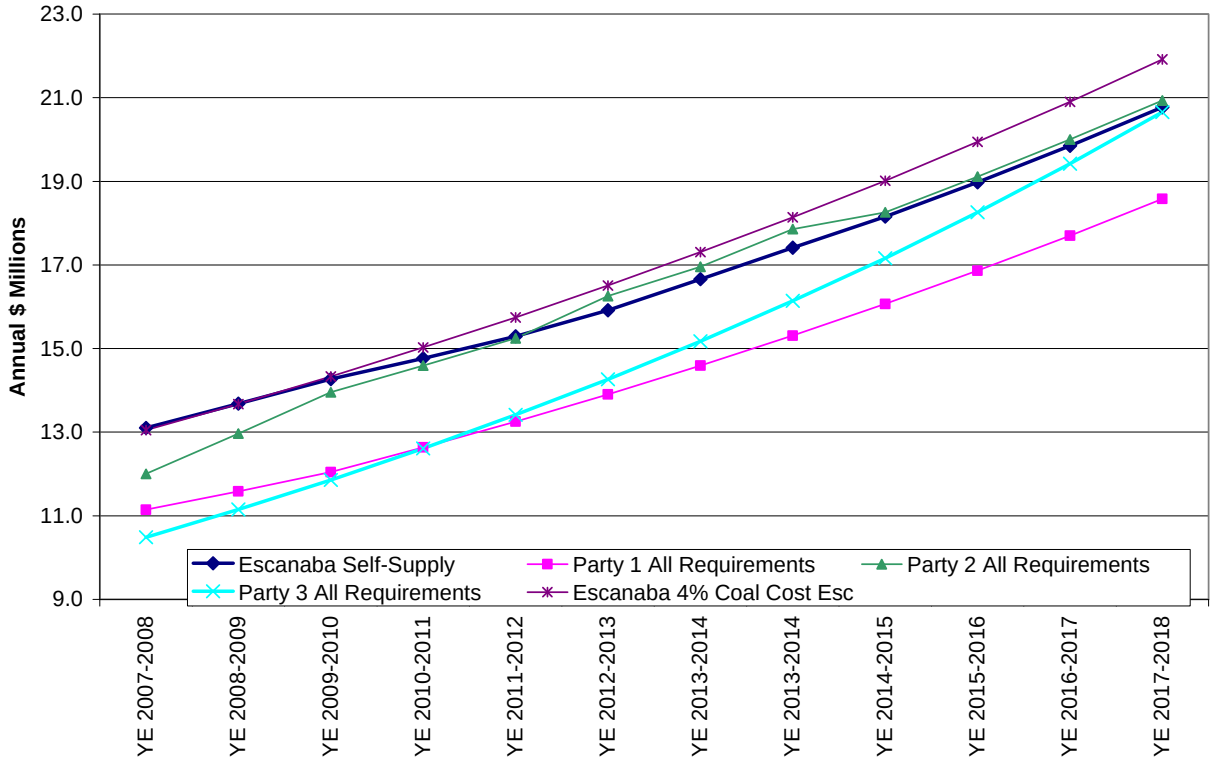

Figure 4.6 - Escanaba Projected Cost of Electricity
Self Generation Compared to All Requirements Alternatives

Projected costs for the Escanaba Self Generation Alternative are the highest in the first two years, and are projected to remain higher than Parties 1 and 3 and be comparable with Party 2 costs. Party 1 is projected to be about $2 million lower than the Escanaba Self Generation Alternative throughout the study period.

The Escanaba Self Generation Alternative with 4 percent coal projection results in costs being higher than All-Requirements purchase projections for all years. Annual costs for the 4 percent Self

Generation are $2 million higher than Party 1 projected costs in early years, increasing to about $2.3 million by 2017-2018. Self-generation costs using the 4 percent coal projection costs are about $0.5 million to $1 million higher than the Party 2 projection from the study period. Cost projections for Self Generation are $2.5 million higher than Party 3 in early years, and about $1 million higher by the end of the study period.

The net present value of electricity costs has also been summarized for the 2010-2011 through 2017-2018 in Table 4.3.

Table 4.3
Summary of 10 Year NPV Cost Comparisons

Supplier	2010-2011 through 2019-2020	Percent Savings Above Self Supply
Self Supply	$133,106,108	
Self Supply 4% Coal	$138,961,040	4.4%
Party 1	$103,031,556	-22.6%
Party 2	$118,286,096	-11.1%
Party 3	$108,543,020	-18.5%

For the 10 year period chosen, the projected costs of Party 1 are nearly 30 million dollars less than the self supply alternative. This is over 22 percent lower than the self supply alternative. The minimum savings for making a decision to switch suppliers has not been established, but this level of projected cost savings is significant.

4.7 Revenue Projection from Selling Energy to MISO Market

An analysis was performed showing the amount of revenue expected by selling Escanaba generation into the market. Generation was based on the historic generation pattern from June 2006 through July 2007 with a modification for the May 2007 generation data to replace energy that was used during the lightning outage. Party 1 made a proposal that Escanaba has the option to sell energy into MISO and receive revenue while purchasing All Requirements energy. If the revenue from the MISO sale is adequate to cover all generation costs, the option could be considered. The assumption of the LMP market price is pivotal in making this decision, as it will directly drive the results. Figure 4.7 shows the incremental operation costs (Coal and Ash costs), total operation costs (All Steam related expenses), and the projected LMP that has been weighted to the shape of the generation MW values.

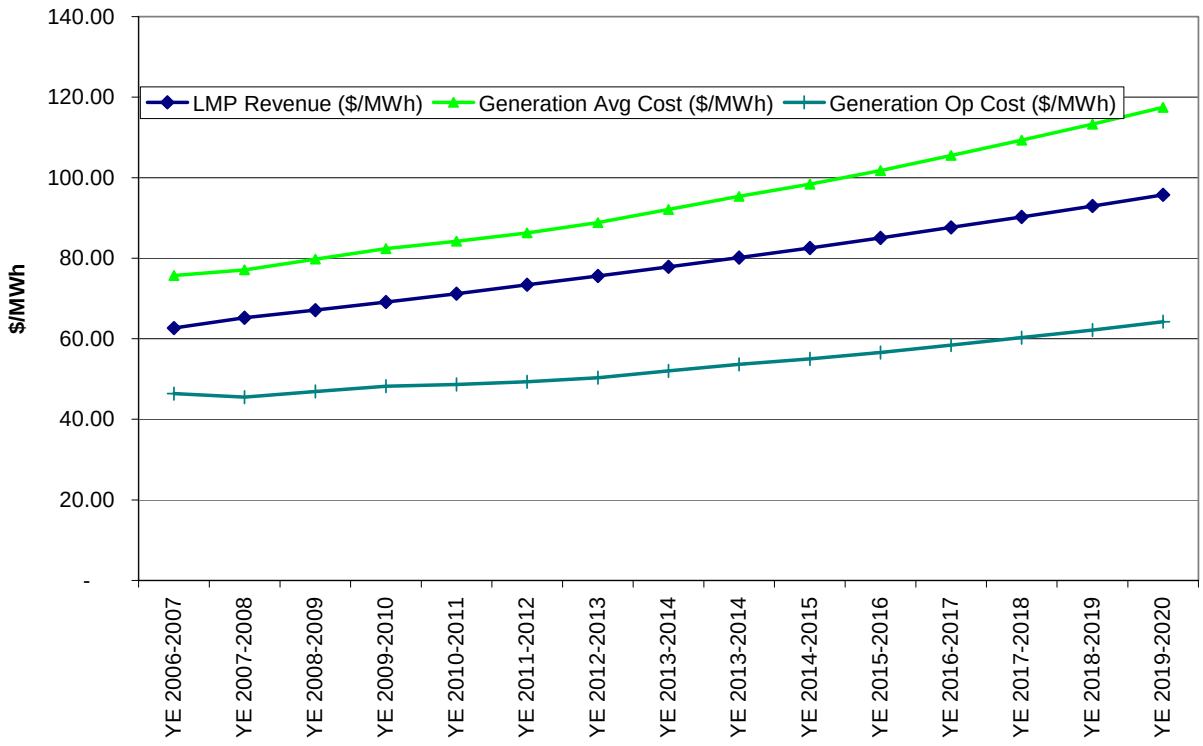

Figure 4.7 - LMP Revenue vs. Generation Cost

Generation operation costs are consistently lower than the projected LMP for all years (cost lower than revenue results in positive margins), while the generation average cost is higher than the LMP (costs higher than revenue - negative margins).

If generation is dispatched only during hours when LMP is higher than the operation costs, there will be resulting operating margins that can be compared to the fixed costs of operating the plant. The analysis shows that generation of the plant decreases by 40,000 MWh and has operating margins in the range of $3.5 million in the early years, increasing to over $7.3 million by 2019-2020. Fixed costs for the plant are in the range of $4.6 million, increasing to $7.7 million by 2019-2020. Using the projected LMP forecast, it is not projected to be profitable to sell energy into the MISO market. Figure 4.8 compares the gross margins from sales (LMP Revenue less Operation Costs) to the plant fixed costs and shows that the net margins are negative by $1 M for the first year, and breaking even in the 2013-2014 year.

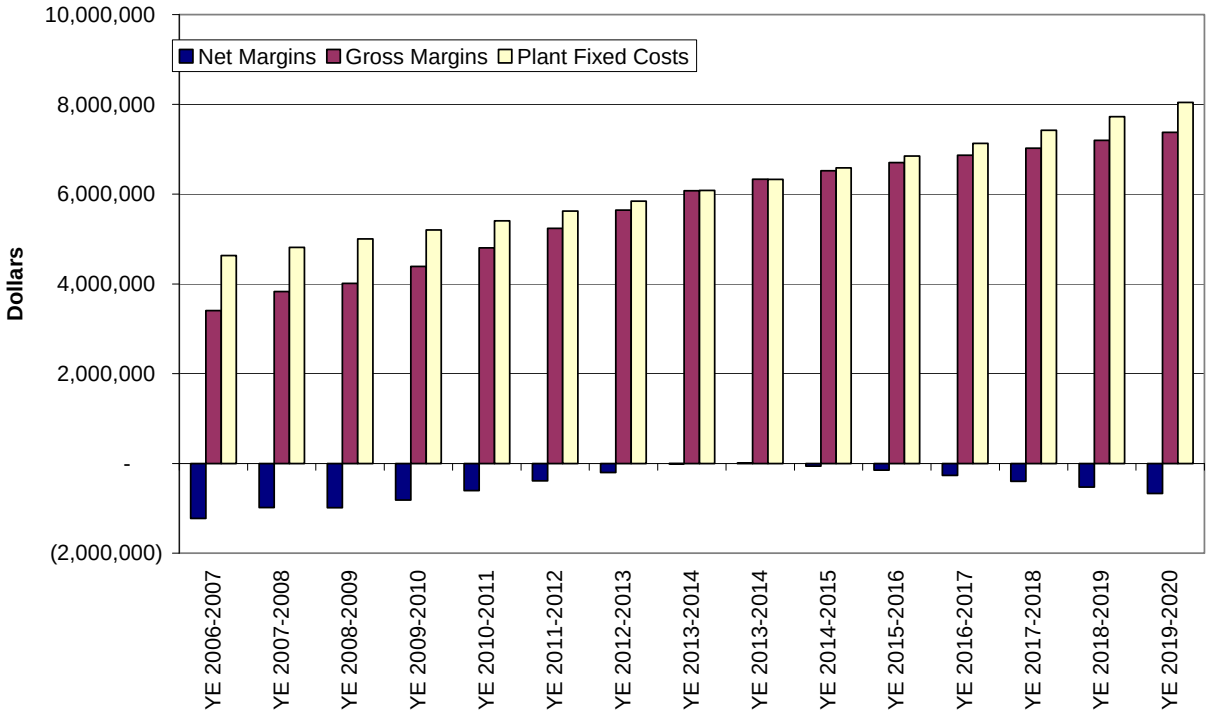

Figure 4 8 - Re-Dispatch Generation Results

4.8 Purchase of 3 MW Block

Proposals from two Parties include the option of purchasing a 3 MW 100 percent capacity factor block of energy. Figure 4.9 shows that the Escanaba Self Generation costs are nearly the same as the options without the 3 MW purchase. From a cost perspective, the alternative to purchase 3 MW is nearly the same and would provide the benefit of getting resources from another type of resource.

Transmission service would be required for this purchase; more specifically point to point transmission could be purchased. This would require making application to MISO for 3 MW. Pricing for the point to point transmission is based on the original request, and if a higher purchase is needed, it results in additional transmission purchases. There is concern that once point to point transmission service is purchased for a 3 MW purchase, it will result in a floodgate of point to point transmission charges for times when the purchase amount is higher due to the plant being out of

service. In short, the block amount of purchase is the right size when resources are available, but is not enough when a unit is not available.

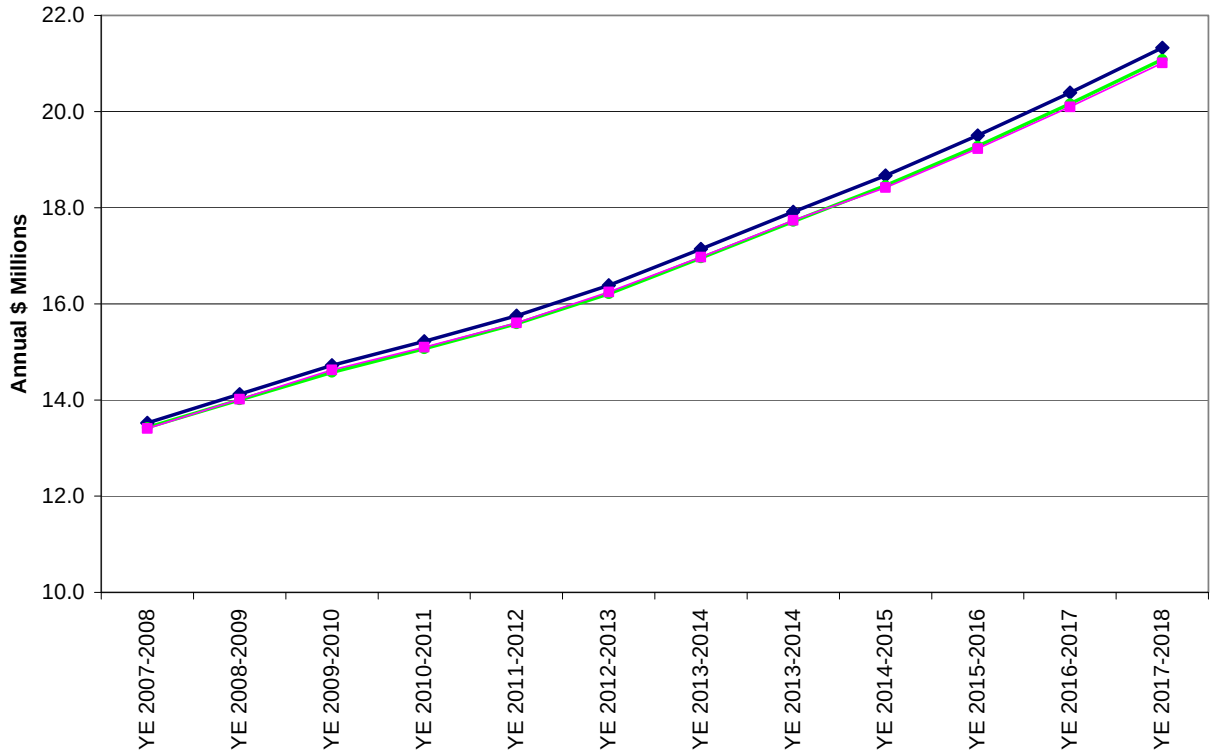

Figure 4 9 - Escanaba Projected Cost of Electricity
Self Generation Compared to 3 MW Purchase Alternatives

4.9 Conversion to Western Coal

Western coal from the Wyoming Powder River Basin(PRB) is considered an attractive fuel for power plants across the country, due to low cost and sulfur content. The PRB coal cost at the mine according to the Department of Energy Annual Energy Outlook (AEO) 2007 report is 7.36 $/ton or $ 0.42/mBtu. It appears that the AEO PRB projection is too low, and two other sources are showing a 2008-2009 PRB price at the mine of $11.87/ton or $0.67/mBtu. According to the two sources, the PRB coal at the mine price is projected to escalate at 3 percent annually. The 2008-2009 estimate for transporting the coal by rail to Escanaba is $27.70/ton and is projected to escalate at 4 percent annually. This results in a PRB 2008-2009 coal cost of $2.25/mBtu. Eastern coal is projected to be $3.04/mBtu for this same time period. Comparing fuel costs on a $/mBtu basis allows a more direct

comparison of the cost than comparing $/ton because the PRB coal only has 8,800 lb/Btu, and Eastern coal has 12,500 Btu/lb. Figure 4.10 shows the delivered cost of both PRB and Eastern coal.

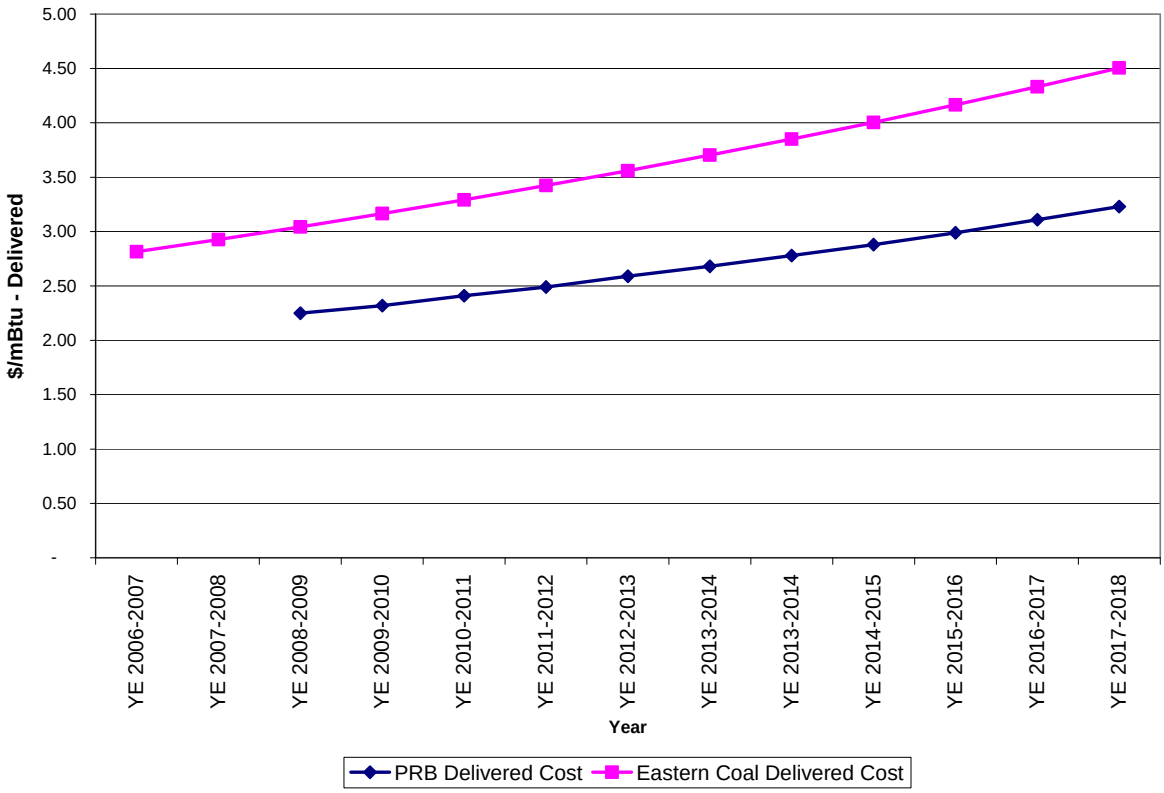

Figure 4 10 – Comparison of Eastern and Western Coal Costs

This difference in cost is about $0.75/mBtu for 2008-2009 and would result in savings $1.8 M per year. This can be considered "gross savings" because it does not take into account additional ash handling costs, and replacement power costs due to lower plant output. When burning PRB coal, the boiler will be required to burn 40 percent more coal (tons) compared to burning eastern coal. PRB coal requires 40 percent more coal to get the same amount of heat. This may be a challenge in terms of having adequate fuel handling and may derate the unit in terms of the net unit output. For the purpose of this analysis, it is assumed that the plant will be reduced by 10 percent. The analysis assumes power lost due to fuel handling constraints is replaced with MISO market purchases. There may be a range of plant modifications available, each with its own level of plant derating. A more detailed engineering study would be needed in order to determine this level of details.

The resulting value of including additional ash handling and reduced output of the plant is in the range of $740 K per year increasing by about 4.2 percent annually. The 10 year NPV of the fuel savings taking these factors into account is $9.6 M. Economic analysis typically takes into account the uncertainty of costs estimates and the need for return when making a capital investment. Using a 15 percent return on capital, the NPV value is adjusted down to $8.1 M.

Table 4.4
Summary of 10 Year NPV Cost Comparisons

Case	NPV Savings	15% ROI	Net Savings
5 Year Payback	4.8 M	0.7 M	4.1 M
10 Year Payback	9.6 M	1.4 M	8.2 M

Economic analysis at this point shows that plant modifications of $4.1 M and a five year payback on could be justified based on the fuel savings projections. The investment for a 10 year payment is $8.2 M.

4.10 Impact of Carbon Tax

The electric utility industry has made a dramatic change in 2007 from typically have a position of fighting proponents of global warming to a position of actively reducing carbon emissions. Carbon taxes are typically designed to raise revenue to fund renewable resources. Carbon emissions from coal generation is just over 1 ton of CO2 per MWh, and 0.7 tons of CO2 emissions per MWh for gas generation.

In order to quantify the impact of a future carbon tax, the fuel mix of alternative power supply parties is generalized to be defined as 60 percent coal, and 40 percent natural gas. Generation from Escanaba is assumed to be 90 percent coal and 10 percent from gas due to outside energy purchases.

Escanaba load for 2009-2010 is projected to be 164,135 MWh and this value will be used to compare the impact of a Carbon tax. For a carbon tax of $15/ton of CO2, the self generation

alternative would result in $2.388 M of additional costs. For an all requirements purchase, the tax would be $2.166 M or $222,000 less than the self generation alternative.

4.11 Consideration of Biomass Fuel

Biomass is generally defined as a renewable fuel material that is grown such as trees, switchgrass, crop residue etc. The Upper Peninsula has vast forestry resources where trees are harvested for both paper and lumber. Tree harvesting operations often leave the tops of the trees and are typically utilized by chipping operations. There is a large demand for landscaping wood chips, but the chips can also be used to fuel the Escanaba Steam station.

Biomass fuel from wood chips is estimated to have a heat content of 4,500 Btu/lb, which would require 2.7 times as many tons of fuel through the boiler than Eastern Bituminous fuel that is rated at 12,500 Btu/lb. This is likely to reduce the output of the plant and for the purpose of the analysis a factor of 20 percent is assumed. The analysis assumes power lost due to fuel handling constraints is replaced with MISO market purchases.

Cost for the biomass is difficult to project for the long-term as it depends on the number of chipping operations and the demand for chips for other uses. Current prices for delivered chipped tree tops range from $25-30/ton, and a 2007 value of $28/ton or $3.11/mBtu is used for the analysis. . Future biomass costs are assumed to escalate at 4 percent annually in the study.

The 2008-2009 cost of biomass generation is higher than Eastern Coal due to the higher cost of fuel and projected decrease in generation. Biomass fuel costs of $3.36/mBtu are higher than the 3.04/mBtu cost of Eastern Coal. This results in nearly $750,000 a year in additional costs and increases to over $900,000 a year in five years. An additional factor that is needed to assess the total cost differential is the 20 efficiency loss due to the lower Btu content of the fuel. The total cost increase taking both of these factors into account is $2.2 M and increases to $3.3 M in 10 years.

This analysis is assuming that there are not any capital cost improvements. If capital improvements are required, this must be taken into account when negotiating the value of the biomass generation.

Figure 4.11 shows the average cost of steam generation using eastern coal, and the higher cost of generation using biomass fuel.

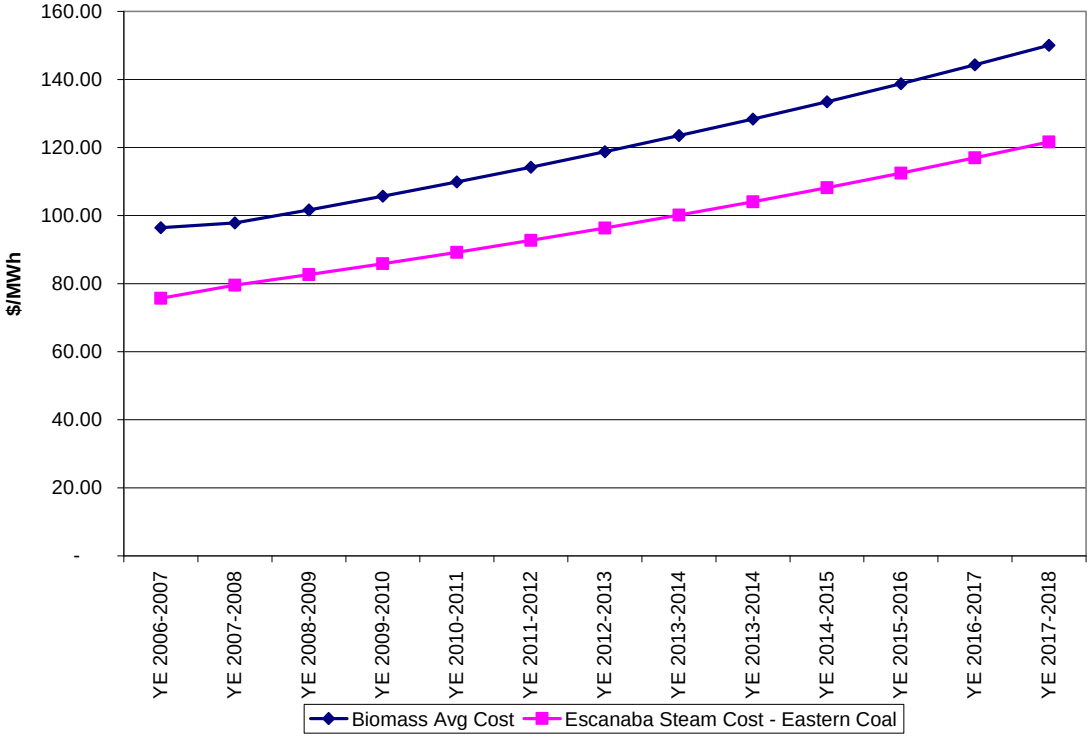

Figure 4 11 – Comparison of Average costs - Biomass and Eastern Coal

One useful metric for the biomass is the additional $/MWh for the generation that a party interested in purchasing would need to provide Escanaba. The biomass option is $20/MWh higher than the Average costs burning eastern coal in the early years, and increases to $25/MWh in later years. The projected total cost of biomass generation for 2008-2009 is just over $100/MWh. These values can be used as a starting point to discuss the level of interest with other parties. The costs of plant modifications will be compared, desired payback period, and return on investment will be compared to the projected revenue or billing credits in order to determine if biomass generation is cost-effective.

4.12 Conclusions

There is significant projected savings when considering purchasing All Requirements power from Party 1, in the range of $2 Million dollars a year. The change from earlier discussions on the cost

comparisons is due to the method of making a coal projection, where the transportation and handling component is assumed to track from the most recent historic year, increasing at 4 percent annually. The City is in a position to make an informed decision on the power supply options and can decide if steps are to be taken to pursue an alternative power supply arrangement, or continue to generate power.

There are a number of reasons beyond the cost comparison to maintain the current power supply arrangements. Local generation provides a higher level of reliability than purchasing power from another supplier, and in the event of a regional blackout, for most hours the City could maintain power to its customers. There is also a benefit on having the local generation in keeping the LMP lower, as it has been shown that increasing the generation above what is needed for the local load lowers the LMP. Economic benefits of having employment at the plant is another factor that is not easy to quantify, but can be considered a benefit to the community.

Ultimately, the city must make a decision to either continue to generate the majority of energy from its resources, or pursue an agreement with another party. There is a three year window to making a decision of purchasing from another party, due to the operating contract for the plant, and the timeframe required to construct transmission for serving the load. As the load continues to grow, decisions can be made to purchase either a high capacity product (3 MW 100 percent purchase as an example), or a load following purchase. Concerns remain about the increased exposure of purchasing transmission, with the ultimate result of possibly needing to purchase network service for the entire Escanaba load (cost of $1 M annually). It appears to be prudent to purchase energy through the UPPCO interconnection agreement, rather than pursue transmission service from point to point or network service.

Given the fact that a three year notice is needed before making a decision to pursue an All Requirements alternative, it is likely to be worth refreshing the analysis in 18-24 months and see how the alternatives compare. Having defined criteria in the economical analysis will be necessary before deciding to change suppliers and close the plant. One example of the savings is 15 percent minimum savings compared to the self generation alternative over a 10 year period.