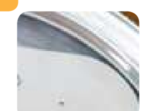
REPORT | January 2018

MUNICIPAL UTILITY FEASIBILITY STUDY

Decorah Power



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EXECUTIVE SUMMARY

In the summer of 2017, Decorah Power contracted with NewGen Strategies and Solutions, LLC (NewGen) to conduct a preliminary investigation into the establishment of a municipal electric utility (MEU) to serve the citizens and businesses of the City of Decorah, Iowa (Decorah or the City). Decorah Power is a non-profit organization of Decorah area citizens dedicated to exploring the opportunity to create an MEU for locally-controlled electricity service. The Decorah City Council approved the organization of Decorah Power and approved the development of a Feasibility Study (Feasibility Study or Study) for an MEU in March 2017. Interstate Power and Light, a wholly-owned subsidiary of Alliant Energy Corporation (referred to herein as Alliant/IPL), currently provides electric services in Decorah and to portions of the surrounding area. This report provides the results of the Study conducted by the NewGen Project Team, which includes Dave Berg Consulting, LLC (DBC) and Exponential Engineering Company, LLC (Exponential).

The intent of this Feasibility Study is to develop a financial analysis of Decorah MEU's projected average system retail rate compared to Alliant/IPL's similar average system retail rate for the Decorah area. The MEU average system retail rate includes recovery of estimated operating costs, including debt service payments associated with acquiring the physical assets of the Alliant/IPL distribution system within and around Decorah. The value of the existing Alliant/IPL assets was estimated based on a field assessment and replacement cost analysis conducted by the NewGen Project Team and the application of estimated accumulated physical depreciation resulting in a Replacement Cost New Less Depreciation (RCNLD) value. The RNCLD value was used to estimate the purchase price to acquire the system in the Feasibility Study since it has been utilized by the Iowa Utility Board (IUB) in its review of previous municipalization efforts in Iowa. MEU rates also include estimates for power supply; transmission, and operations and maintenance (O&M) of the distribution system; customer costs; and other charges. This analysis was conducted for a 10-year period beginning in 2018. This report is the result of the Feasibility Study, which includes estimates regarding several key assumptions based on visual reviews of the system assets and professional experience.

Concurrent with this Feasibility Study, Decorah Power developed a qualitative assessment of the benefits of an MEU. These benefits include economic benefits associated with locally-owned utility and associated businesses, investments in renewable energy, and the ability to determine its own energy future. The focus of this report is the financial analyses developed by the NewGen Project Team. However, the qualitative benefits identified by Decorah Power are included by reference as indicated herein and can be found in the Decorah Power report, titled *A Vision Shared: Owning the Future Through a Decorah Municipal Electric Utility*.

The results of the analysis conducted for this Feasibility Study suggest that a Decorah MEU could provide service to its customers for a lower average cost while providing reliable power with increased emphasis on renewable energy and local energy management programs. The assumptions regarding the development of the average system retail rates for the Decorah MEU compared to Alliant/IPL are provided herein. Primary drivers for the average MEU system retail rates include the assumptions and estimates for the costs to acquire the system assets, the future power supply expenses, and other operating costs. For this assessment, the NewGen Project Team has made reasonable estimates and assumptions consistent with this level of study, as described herein. If the City decides to move forward with its municipalization of the Alliant/IPL assets, we would recommend further investigation into these assumptions and estimates to further refine the average retail rate comparison analysis.

Section 1
INTRODUCTION

In the summer of 2017, Decorah Power contracted with NewGen Strategies and Solutions, LLC (NewGen) to conduct a preliminary investigation into the establishment of a municipal electric utility (MEU) to serve the citizens and businesses of the City of Decorah, Iowa (Decorah or the City). Decorah Power is a non-profit organization of Decorah area citizens dedicated to exploring the opportunity to create an MEU for locally-controlled electricity. Decorah Power was approved for organizing by the Decorah City Council and authorized to conduct a Feasibility Study (Feasibility Study) for an MEU in March 2017. Interstate Power and Light, a wholly-owned subsidiary of Alliant Energy Corporation (referred to herein as Alliant/IPL), currently provides electric services to Decorah and portions of the surrounding area. This report provides the results of the Study conducted by the NewGen Project Team, which includes Dave Berg Consulting, LLC (DBC) and Exponential Engineering Company, LLC (Exponential).

Decorah Power provided the City Council and other City organizations various sources of information and publications, as well as support for speaking engagements regarding the benefits of owning and operating an MEU. A summary of Decorah Power's expressed benefits of an MEU presented in these communications included:

- Dedicate resources to the welfare of Decorah's citizens and businesses through a locally appointed Board.
- Support a vibrant locally owned business, including the ability to invest operating margins in the local community.
- Offer local opportunity to invest in initiatives and promote community ownership of our energy future.
- Offer relief from long-term generation commitments that can cause unnecessary and expensive overhead for customers to absorb.
- Take advantage of available and emerging technologies to provide cost savings to customers and provide the highest degree of reliability.
- Improve community cash flow when customers make their utility payments locally. Local cash flow provides an economic multiplier effect important to small communities.
- Help Decorah residents and businesses exercise local control over their sustainability and carbon reduction goals through locally owned electricity generation.
- Offer a "Green/Sustainable Community" marketing advantage.
- Offer community investment and local control for grid security and resilience.
- Potentially proceed with the community-owned shared solar project deemed unacceptable by Alliant/IPL.
- Give more emphasis to the use of local contractors and suppliers.

Further discussion of these points, as well as others, is provided in the accompanying document prepared by Decorah Power, titled *A Vision Shared: Owning the Future Through a Decorah Municipal Electric Utility*.

Feasibility Study

The intent of this Feasibility Study is to determine if Decorah Power should continue with its efforts to establish a locally controlled MEU. The NewGen Project Team designed the scope of work to be accomplished on a phased approach; Phase I results in this Feasibility Study to provide a high-level approach to determine the costs / benefits of establishing an MEU. The Phase I Feasibility Study utilizes publicly available data and other information sources to determine potential ranges in cost savings associated with an MEU for the City. The intent of this Phase I report is to potentially support a City-wide ballot issue in 2018 to determine if Decorah Power and the City should move forward with municipalization efforts. The ballot issue is anticipated to request approval for the development of the MEU.

Phase II efforts anticipate the development of additional detail to provide a defensible basis for the City to move forward with the MEU before the Iowa Utilities Board (IUB). This will include the development of an "application" package, in coordination with legal counsel, for filing with the IUB. Ultimately, the IUB will issue a decision as to whether the City can proceed with its efforts to acquire Alliant/IPL assets and create an MEU. If the IUB approves the transfer of service to the MEU, it will determine the cost the MEU must pay to Alliant/IPL for the assets and will define the MEU service territory. Details regarding the Phase II efforts will be further determined if the City decides to move forward with the MEU process and chooses to utilize the services of the NewGen Project Team. Estimated costs for additional technical analysis, as well as legal/consulting services to guide the City through the process of creating an MEU are included as "start-up costs" in this Feasibility Study. If the City is successful in developing an MEU, it is anticipated that these costs would be repaid to the City through the rates charged for providing electric service to its customers.

Phase I Feasibility Study Elements

The following highlights the Phase I Feasibility Study elements:

- Define potential MEU service area as the existing customers served by Alliant/IPL from the distribution equipment emanating from the Decorah substation.
- Determine an initial estimate of the value of Alliant/IPL assets utilizing publicly available data and the asset inventory derived during the limited on-site field review.
- Develop an estimate of severance and reintegration issues and analysis based on a limited on-site field review.
- Prepare high-level load forecast analyses based on available data.
- Review existing Midwest Independent System Operator (MISO) wholesale power market prices to preliminarily project power supply costs.
- Determine preliminarily estimated start-up, financing, operations and maintenance (O&M), and administrative and general (A&G) costs utilizing publicly available data and NewGen Project Team and Decorah Power professional experience.
- Project estimated costs (rate revenues) of providing MEU service (i.e., revenue requirement), compared to the costs (rate revenues) under continued Alliant/IPL service.
- Provide a subjective list of items to consider beyond results of analyses in previous tasks including other benefits, risks, and uncertainties.

- Prepare a report that present the results of the Phase I Study.
- Attend an on-site project kick-off meeting and present the Phase I Feasibility Study results to the Decorah Power Board of Directors and the City Council.

Feasibility Study Process

The Phase I Feasibility Study was initiated with an on-site meeting in Decorah on August 11, 2017. Detailed information on the electric system within the City was requested from Alliant/IPL by Decorah Power, but was not provided due to confidentiality concerns. Subsequent arrangements were made for the NewGen Project Team to begin field activities in September. Decorah Power and the NewGen Project Team initiated continuing communication to facilitate review of Study results and address concerns raised during the Study process. One issue quickly identified during the field review was regarding the potential service territory for the MEU.

The existing Alliant/IPL distribution system serves the City and surrounding areas from the Decorah Substation. Specifically, the Decorah Substation includes two transformers that step power down from the transmission lines to distribution level voltage and five distribution feeders leaving the substation. The initial field review included an assessment of the required process to physically separate the existing system from a proposed MEU within the City limits. It was determined that to physically separate the distribution system solely within the City limits would require the development of redundant systems at a prohibitive cost. This was deemed to not be in the public's best interest (for City and non-City residents) regarding efficient provision of service.

Therefore, it was decided that the MEU would need to acquire all the distribution related equipment within the Decorah Substation and into the surrounding areas and become the electric provider for all existing and future customers served by those systems. This approach would expand the service of the MEU beyond the municipal boundaries of the City. This approach is consistent with past IUB rulings concerning municipalization efforts and is sound policy for reducing unnecessary costs for consumers. Based on these initial findings, the NewGen Project Team scope of services was expanded to include an additional field assessment of the assets extending from the Decorah Substation beyond the municipal boundaries. For the purposes of this Feasibility Study, this potential service area is referred to as the "Greater Decorah MEU."

Field Investigation

The field investigation included approximately eight days of on-site, visual review of the Greater Decorah MEU service territory. The NewGen Project Team field engineer was provided assistance from a student intern at Luther College, whose contributions were greatly appreciated. The field engineer also worked with the Winneshiek County Planning Department personnel, who provided additional information for Geographic Information System (GIS) maps. The NewGen Project Team created base level GIS maps from satellite and aerial photography and field reconnaissance. These maps were utilized to catalogue the field inventory as well as to produce a schematic of the Greater Decorah MEU service territory, as provided by Figure 1-1.

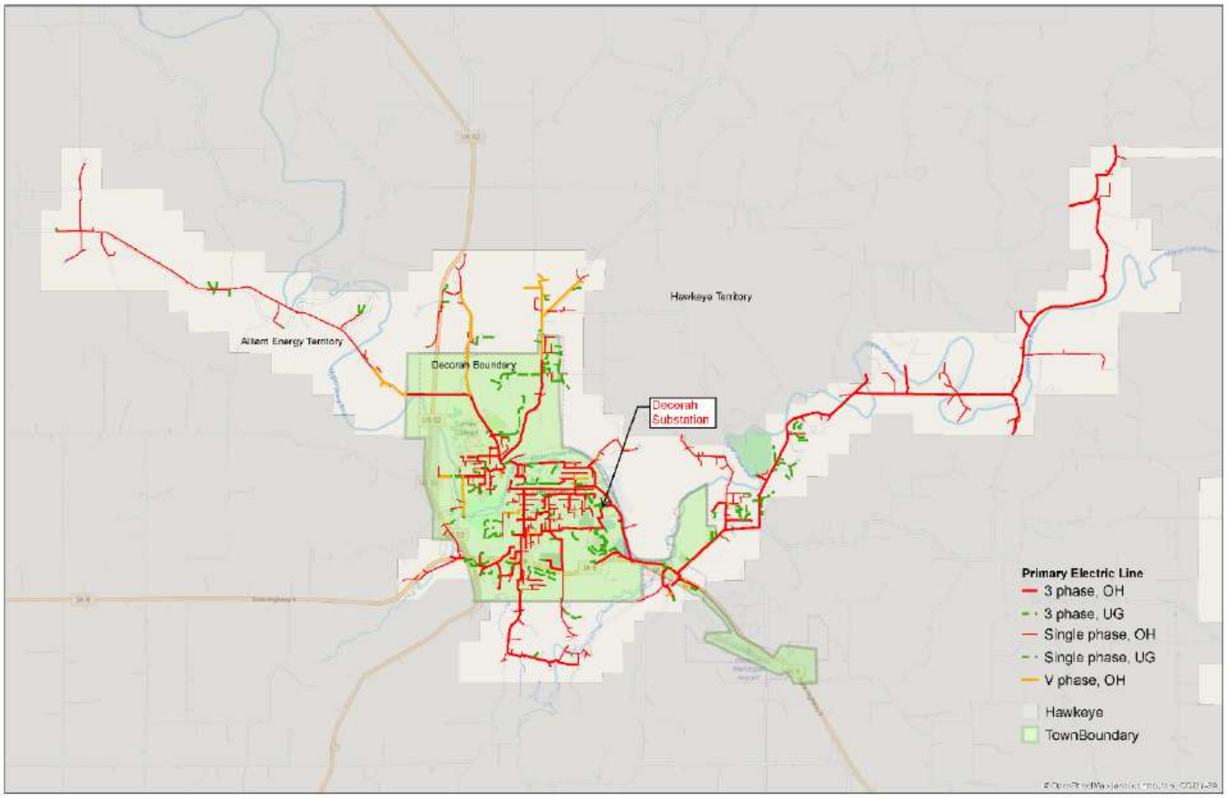

Figure 1-1: Greater Decorah MEU Service Territory Schematic (Approximate)

The field review also included the development of an initial inventory of the size, type, and estimated age of assets within the Greater Decorah MEU. A summary of the findings from the field review is provided in Table 1-1 below.

Table 1-1
Asset Inventory – Estimated from Field Investigation

FERC Account	Description	Quantity (ft.) (1)
Account 362 – Substations	Decorah Substation	4,000 ft. sq.
Account 364 – Poles, Towers, Fixtures	Support for Overhead Distribution Lines	535,630
Account 365 – Overhead Conductors and Devices	3 Phase / 1 Phase Overhead Distribution Lines	349,879
Account 365 – Underground Conduit Installations	Buried Conduit - 3 Phase / 1 Phase	130,394
Account 367 – Underground Conductors and Devices	Buried Conductor - 3 Phase / 1 Phase in Conduit	130,394
Account 368 – Transformers	3 Phase / 1 Phase Overhead / Padmount	1,080
Account 369 – Services	Service drops, conductor, support equipment	3,434
Account 370 – Meters	Customer meters, hardware	3,434

(1) Estimated linear feet from GIS mapping

As indicated, the NewGen Project Team conducted a limited field investigation to estimate the amount, condition and age of the distribution facilities within the Greater Decorah MEU area. Figure 1-2 below is a picture of the existing Decorah Substation.

Figure 1-2: Decorah Substation

Replacement Cost New Less Depreciation

The NewGen Project Team utilized the information developed from the field inventory to produce an estimate of the value of the assets utilizing a Replacement Cost New Less Depreciation (RCNLD) approach. RCNLD is an industry term for estimating the value associated with replacing existing assets with the same or similar new equipment, adjusted to reflect accumulated physical depreciation. The NewGen Project Team utilized the detailed inventory and obtained competitive quotes for the various new equipment, devices, and associated labor for installation. The NewGen Project Team also developed an estimate of the age of the assets reviewed for purposes of determining the amount of depreciation or useful life left within the system. The results of the field investigation indicate that the majority of the equipment currently serving the Greater Decorah MEU area has incurred significant depreciation relative to its useful life.

The RNCLD valuation approach has been utilized by the IUB in its review of previous municipalization efforts in Iowa and has been estimated for this Feasibility Study. In general, the NewGen Project Team believes that the RCNLD approach overstates the fair market value of the assets to be acquired. This is because the incumbent utility (investor owned utility) receives a return (profit) from the Original Cost Less Depreciation (OCLD, also referred to as book value) of the assets. This type of utility model encourages investment from the utility owner by tying the profit allowed to the amount spent for equipment and systems. However, the OCLD approach typically results in a lower value than the RCNLD, as it is not contingent on pricing new equipment, but rather the cost of the equipment when originally installed. If the City chooses to move forward with this project, the NewGen Project Team intends to argue before the IUB that the OCLD value is a more representative valuation of the assets to be acquired for the MEU.

Estimates of accumulated depreciation were derived from survivor curves utilized by Alliant/IPL in their regulatory filings and applied to each class or group of assets as applicable. The following table provides a summary of the replacement costs, the accumulated depreciation, and the RCNLD value for each asset class by Federal Regulatory Energy Commission (FERC) account. In addition to the FERC accounts for equipment, a preliminary estimate of the value of an existing warehouse was included in the RCNLD. The value of the land upon which the Decorah Substation exists was estimated by Decorah Power and represents a non-depreciable asset (land does not depreciate). The total Replacement Cost New (RCN) estimate is approximately $14 million, whereas the RCNLD is approximately $5 million, which indicates an estimated depreciation (for the Greater Decorah MEU system) of approximately 65% (or 35% of the RCN value is remaining).

Table 1-2
Asset Inventory – Estimated from Field Investigation

FERC Account	Description	RCN	Depreciation %	RCNLD
Assets Acquired				
362.10	Decorah Substation	$4,336,000	68.25%	$1,376,680
364.00	Poles, Towers, Fixtures	2,562,567	69.86%	772,358
365.00	Overhead Conductor	507,506	65.25%	176,358
366.00	Underground Conduit	1,203,840	56.77%	520,420
367.00	Underground Conductor	827,979	71.72%	234,152
368.10	Transformers- Overhead Line	1,028,800	75.21%	255,040
368.20	Transformers – Padmount	1,308,515	75.21%	324,381
369.10	All Service	729,375	69.88%	219,688
370.00	Meters	1,401,322	19.99%	1,121,198
N/A	Warehouse	50,000	25.00%	37,500
Subtotal		$13,955,904		$5,037,775
Real Property Acquired				
Land & Land Rights - Substation		$50,000	N/A	$50,000
TOTAL PROPERTY ACQUIRED		$14,005,904		$5,087,775

Alliant/IPL Retail Rates

Estimates of the projected Alliant/IPL retail rate were determined from published tariffs (in place for 2017, pending IUB approval), proposed rate increases for 2018 (subject to approval), as well as analysis of existing rate riders and other charges from representative customer classes provided by Decorah Power. A summary of the average rate by class for Decorah Alliant/IPL, including rate riders, is provided in Table 1-3.

Table 1-3
Alliant/IPL Average System Retail Rate Estimate

Customer Class	2017 Rate Summer / Winter (1)	2017 Customer Charge/Mo. (1)	2017 Rate Rider (2)	Average Rate by Class (3)
Residential				$0.16583/kWh
Tier 1 – Summer / Winter Energy ($/kWh)	$0.11083 / $0.09189	$11.79	$0.05602/kWh	
Tier 2 – Summer / Winter Energy ($/kWh)	$0.11083 / $0.06712			
Tier 3 – Summer / Winter Energy ($/kWh)	$0.11083 / $0.02532			
General Service				$0.15643/kWh
Tier 1 – Summer / Winter Energy ($/kWh)	$0.11498 / $0.08784	$19.98	$0.05602/kWh	
Tier 2 – Summer / Winter Energy ($/kWh)	$0.09426 / $0.05965			
Large General Service (4)				$0.10843/kWh
On-Peak – Summer / Winter Energy ($/kWh)	$0.02224 / $0.01790	N/A	$0.02960/kWh	
Off-Peak – Summer / Winter Energy ($/kWh)	$0.02224 / $0.00775		$6.67/ kW (Summer)	
Tier 1 – Demand Charges ($/kW)	$17.63 / $9.26		$7.99/ kW (Winter)	
Tier 2 – Demand Charges ($/kW)	$17.48 / $8.45			
Tier 3 – Demand Charges ($/kW)	$17.23 / $7.74			
Tier 4 – Demand Charges ($/kW)	$17.13 / $7.54			
Tier 5 – Demand Charges ($/kW)	$13.87 / $5.62			

(1) Based on published rates for 2017, subject to IUB approval
(2) Based on 2016 Rate Riders from customer bills provided by Decorah Power and review of proposed rates by Alliant/IPL, includes Energy Adjustment Clause, Energy Efficiency Cost Recovery and Regional Transmission Service Clause
(3) Average based on analysis of various usage types per class, includes applicable taxes
(4) Includes analysis for Luther College, based on billed data net of on-site solar PV generation

Estimation of MEU Load

The estimation of the MEU electric load by class was determined from an analysis of the average Alliant/IPL load data (as published in their federal forms), as well as specific bills obtained from larger commercial customers by Decorah Power and the field investigations. A review of the entire Decorah population suggests that from 2010 to 2016, the local census has decreased by approximately 200 people. It is assumed that during this period, load growth also declined with the reduction in population, as well as the increase in energy efficiency appliances/programs and increased participation in distributed (on-site) generation. For the purposes of this analysis, we have estimated that the total load would remain constant through the period of this Study.

The NewGen Project Team field review included documenting and cataloguing the existing meters utilized to serve Alliant/IPL customers within the Greater MEU service area. This included determining if the meters were providing service to residential, small commercial, or large commercial customers. The number of residential customers was estimated from the field observations, GIS maps and industry experience. Electric usage per month for residential customers was determined from the average usage per residential customer reported by Alliant/IPL.

For small commercial customers, it was assumed that the MEU would serve the total number of small commercial customer meters determined from the field investigations and other sources. Similar to residential customers, the number of small commercial customers was held constant for this analysis. The average load for small commercial is assumed to be equal to the average load for Alliant/IPL.

The number of large customers (as well as their load) was estimated from an analysis of the bills provided to Decorah Power from those customers within and surrounding Decorah, as well as information obtained during the field investigation. The total net load for Luther College was also included for this analysis, which includes the energy reduction due to its on-site solar photovoltaic (PV) system. Load for all customers is projected to stay constant throughout the Study, as any potential increases in load would be expected to be reduced by increases in energy efficient appliances/programs, as well as increased adoption of distributed generation resources. A summary of the customers and load analysis is provided in Table 1-4 below.

Table 1-4
Customer Number and Load Estimates (1)

Customer Class	Number of Customers	kWh/Month/ Customer	Total Annual kWh Sales
Residential	2,770	772	25,654,278
Small Commercial	561	4,179	28,130,820
Large Commercial	102	49,091	60,087,972
Luther College	1	1,017,100	12,205,200
TOTAL	3,434		126,078,269

(1) Estimated customers / load based on information provided by Decorah Power and Alliant/IPL (see text).

Net Energy Metering

Net Energy Metering (NEM) typically refers to rate and rate programs offered to customers who install distributed energy resources, generally solar PV systems, on their premises. These systems are usually installed “behind the meter”, meaning that the energy produced by these systems is typically utilized by the electric load of the customer. Net Energy Metering has become a significant issue in recent years with the widespread adoption of distributed solar PV, driven by reduced costs and increased acceptance by customers. Utilities offer specific programs or rates for NEM in which they specify how the energy produced by the distributed system is valued. Some utilities state the amount they will pay for energy that is fed back to the distribution system (i.e. over production) and some offer specific rates based on a “value of solar” concept. If a utility does not offer a specific NEM rate, a customer can potentially still save on their energy bills by offsetting their monthly energy usage with the output from their distributed system.

Alliant/IPL currently offer NEM rates under its Net Metering Pilot, where it allows for over-production energy to be carried forward and applied to the following month’s bill and paid out annually at its avoided costs (the costs for Alliant/IPL to provide energy). Net Energy customers are subject to various rules and regulations per Alliant/IPL rates, as well as applicable Iowa state statutes. This rate offering is typical for many utilities, including investor owned (like Alliant/IPL) and consumer owned (like the MEU).

Alliant/IPL has indicated publicly that approximately 4% of Decorah customers are NEM customers, however, they have not provided specific information on the amount of installed capacity of the NEM customers, or the amount of energy produced from these systems on an annual basis. Presumably, this

4% includes the solar PV facilities located at Luther College, the effect of which is included in the specific billing data provided for this Study.

In general, the existence of solar PV systems within a service territory would serve to reduce energy sold to end users. This would reduce the amount of energy required to be purchased by the MEU from its wholesale energy provider, which would reduce some operating costs. However, generally, distributed solar PV systems would not reduce certain fixed costs associated with the MEU owning and operating the utility in the short-term. If the amount of installed capacity of distributed solar PV exceeds a certain threshold, the result could be a cost burden placed on non-solar PV customers. The issue of specific NEM programs and policies appropriate for the Decorah MEU would be determined by the MEU Board of Directors and/or City Council at a future date.

2017 Average Retail Rate for Decorah Alliant/IPL

The average retail rate for customers within the Decorah area served by Alliant/IPL was determined from an analysis of their average system retail rates and proportion of total estimated load for Decorah. The estimation of the MEU electric load by class is provided in Table 1-4 above. The average retail rates by class for Alliant/IPL determined in Table 1-3 were adjusted based on representative customers weighting to reflect the customer mix within Decorah. The large commercial class average rate was adjusted for specific cost information provided by Luther College. The weighted average rate (weighted by percent of customers class by load) was determined for each class and summed to create an average retail rate for Alliant/IPL for the Decorah area for 2017. For the purposes of this Study, Alliant/IPL rates were assumed to increase annually at the current rate of inflation of 2.1%. Table 1-5 below provides a summary of the analysis developed for the Alliant/IPL 2017 average retail rate for the Decorah service territory.

Table 1-5
Average Retail Rate for Alliant/IPL Customers in Decorah (1)

Customer Class	Average Retail Rate by Class ($/kWh) (2)	kWh Load (Annual)	% of Customers by Load for Decorah (3)	2017 Weighted / Average Rate for Decorah Alliant/IPL (4)
Residential	$0.16583	25,654,278	20.3%	$0.0337
Small Commercial	$0.15643	28,130,820	22.3%	$0.0349
Large Commercial (5)	$0.11264	60,087,972	47.7%	$0.0537
Luther College	$0.08315	12,205,200	9.7%	$0.0081
TOTAL		126,078,269		$0.13037

(1) Estimated average retail rate for Alliant/IPL customers in Decorah area for 2017 (see text)
(2) Average Retail Rate by Class, including rate riders, from Table 1-3
(3) Percentage of total annual load by class
(4) Sum of the percentage times the average retail rate
(5) Large commercial rate excludes Luther College net load

Section 2
FINANCIAL MODEL DEVELOPMENT

The NewGen Project Team developed a financial model to determine the financial feasibility of creating an MEU for the City of Decorah and surrounding areas. The financial model develops an estimated cash flow for the MEU based on a series of inputs, as described below. The operating revenues are assumed to equal the sum of the operating expenses, the non-operating expenses and a margin required to fund operating reserves. The total revenue requirement is divided by the total sales to determine an "average system rate" for the MEU. Similarly, an average system rate was determined from an analysis of Alliant/IPL rates within the Decorah area as provided in Table 1-5. The financial model compares the annual average system rates over the Study Period (2018 – 2027).

A summary of the cost items included in the financial model for the first year of analysis (2018) is provided in Table 2-1, and discussed herein. The average retail rate for Decorah Alliant/IPL is the result of the 2017 rate developed in Table 1-5 increased for one year of inflation (2.1%). A summary of the financial model results for all years of analysis is provided in Appendix A.

Table 2-1
MEU Financial Model Results for Year 1

Line Item	2018 Value ($000) (1)
Operating Revenues	$11,445
Projected Operating Expense	
Power Supply Expense (2)	$5,384
Transmission Expense	2,198
Distribution / Customer / G&A Expense (3)	1,400
O&M Fee (4)	105
EE/DSM Programs (5)	572
Total Operating Expenses	$9,659
General Fund Transfer (5% of Gross Revenue)	572
Renewals and Replacements / Normal Capital	339
Total Debt Service (6)	607
Total Expenses	$11,177
Margin / Operating Reserves	$268
Average Retail Rate Analysis	
Total Sales (kWh)	126,078,269
Average Decorah MEU Rate ($/kWh)	$0.0908
Average Decorah IPL Rate ($/kWh)	$0.1331

(1) Numbers may not add due to rounding
(2) Assumes Market Purchases (70%) and JAA/G&T (30%)
(3) Total Operating Expense for Distribution / Customer / A&G based on professional experience
(4) O&M Fee estimated to be 15% of Distribution O&M costs
(5) EE/DSM Programs estimated to be 5% of Operating Revenue
(6) Total Debt Services – Acquisition and Start-Up Costs

Financial Model Assumptions

A series of assumptions have been utilized in the development of the financial feasibility model. These have been categorized as those related to the distribution assets, the initial operation of the MEU, and the continued operation of the MEU over the Feasibility Study Period. A summary of these assumptions is provided below.

Distribution Assets

As indicated in Section 1, the distribution assets to be acquired for the creation of the Greater Decorah MEU include the high-side protection, substation transformers and the distribution portion of the Decorah Substation, the five feeders identified during the field review that originate in the substation, and the associated equipment necessary to serve the various customers within and around the City. It has been assumed that the MEU will own the substation and the various distribution equipment from the point where the transmission (high voltage) lines connect to the various transformers and all the remaining equipment that conveys, transforms, or otherwise manages the power at the distribution level (low-voltage). The transmission equipment and the high voltage circuit breakers will remain as part of the ITC transmission system. Two metering structures will need to be constructed on the high side of the two substation transformers to provide the point of interconnection between the Alliant/IPL and MEU systems. A summary of the equipment is provided in Table 2-1 above.

For the purposes of the feasibility analysis, it has been assumed that the MEU will be able to finance the acquisition cost of the Alliant/IPL assets over a 20-year period utilizing taxable debt. The taxable debt interest rate utilized for this analysis is 5.0% per year. It is anticipated that the MEU can issue non-taxable debt as a municipal entity. However, for this Feasibility Study, it has been assumed that for the purposes of acquiring the privately held assets the use of non-taxable debt would provide an unfair advantage for the MEU. Further, it is assumed that required bond counsel would not allow tax free debt to be issued for this specific purpose, as it potentially results in a tax-payer subsidy for the acquisition of private assets. Therefore, for this Feasibility Study, taxable debt is utilized as a funding mechanism for this purpose.

Initial Municipal Electric Utility Operation

The initial operation of the MEU will require a source of cash to fund various activities prior to, and within, the first six months of operations. After this initial period, it is assumed that the rate revenue from energy sales will support the cash needs of the MEU. For the purposes of the financial analysis, we have assumed two categories of initial operation costs; those associated with regulatory/professional services, and those associated with system/labor and other cash needs of the MEU. The regulatory and professional services are assumed to include attorney fees, consultant fees, regulatory fees, and other fees/charges. The total cash necessary for the regulatory/professional services is estimated to be approximately $1 million. This estimate is based on experience in the industry. We have not requested quotes from professional service providers or investigated potential costs for licensing or other fees with local, state, or federal governmental entities for these services.

The other cash needs for the MEU prior to, and during, the start-up period include a requirement for one-year of estimated A&G labor costs, estimated costs to improve existing software/billing systems (adding to the City’s existing system), spare equipment costs (based on the asset inventory described in Section 1), and working capital (cash) for purposes of power supply costs. It has been assumed that these start-up costs can be amortized with the issuance of debt by the MEU over a 20-year period at a tax-exempt rate of 3.5%. This is a simplifying assumption as there may be limitations with the use of bond funds for operations. As noted, if the City is successful in developing an MEU, it is anticipated that the estimated start-up costs would be repaid to the City out of debt proceeds which are repaid through the rates charged for providing electric service to its customers.

A summary of these costs is provided in Table 2-2 below.

Table 2-2
Estimated Start Up Costs for MEU (1)

Type	Description	Amount
Regulatory Fees		
Attorney Fees	Legal assistance	$300,000
Consultant Fees	Technical assistance	200,000
Regulatory Fees	Fees to Local / State / Federal entities	250,000
Other Fees / Charges, etc.	Other types of fees / charges	150,000
Sub-Total (Rounded)		$1,000,000
Front End Start Up Costs		
1 Year of A&G Labor Costs	Estimated A&G	$420,000
Software / Billing System	City W/WW Billing System	50,000
Spare Equipment		
Transformers	Spare transformers on-site	10,000
Conductor	Spare conductor on-site	$13,355
Working Capital	Initial Power Supply / Transmission Costs	500,000
Sub-Total (Rounded)		$1,000,000
TOTAL ESTIMATED COSTS	Sum of Regulatory / Front End Start Up Costs	$2,000,000

(1) Costs estimated based on professional experience (see text)

Continuing MEU Operation

The continued operation of the MEU will require cash for operations, including power purchases (and delivery via the transmission system), utility operating expenses, transfers to the general fund, and maintenance of operating reserves. The following provides a summary of the assumptions regarding the costs for each of these items.

Wholesale Power Market

The Midcontinent Independent System Operator (MISO) operates wholesale electricity markets, which initially encompassed parts of 12 states in the Midwest. In 2013, MISO integrated the MISO South region in Texas, Louisiana, Mississippi, and Arkansas.

The MISO markets include:

- Day-ahead and real-time energy markets, which utilize least-cost resources to meet system demand within the existing the transmission network.
- Financial Transmission Rights (FTRs), which are congestion revenues collected by MISO through its markets fund FTRs.

- Ancillary Services Markets (ASM), which include operating reserves and regulation markets.
- Capacity Market.

Fuel Prices and Energy Production

The continuing decline in fuel prices during 2016 contributed to changes in the generation mix in MISO. In particular low natural gas prices throughout 2016 increased MISO's output from natural gas-fired units and decreased the generation from coal-fired resources.

The lowest-cost energy resources (coal and nuclear) operate at the highest capacity factors and coal continued to produce the greatest share of energy. Natural gas-fired output grew from 24% in 2015 to 27% in 2016, yet remains lower than its 42% share of capacity. Coal-fired resources now constitute a slightly smaller share of MISO's capacity than last year, and they produced 46% of MISO's output in 2016, down from 50% in 2015. Although natural gas-fired units produce a modest share of the energy in MISO, they play an important role in setting energy prices. Gas-fired units set the system-wide price in 44% of all intervals for the year, up from 37% in 2015. Gas-fired resources effectively set the system-wide prices in almost all peak hours, because gas rarely sets prices overnight when prices are lower. Congestion frequently causes gas-fired units to set prices in local areas when lower-cost units may be setting the system-wide price.

Power Supply Options

For this Feasibility Study, the NewGen Project Team developed three potential power supply options for the MEU. The first option is for pure market purchases from the MISO power market combined with an incremental price for renewable energy (wind). The second option is to purchase "all-requirements" wholesale power from an unspecified regional Joint Action Agency (JAA) or Generation & Transmission Cooperative (G&T). The third option is a combination of the two (wholesale power market and partial requirements from a JAA/G&T).

The power market option assumes that the MEU would purchase its entire load from the power market based on published forward pricing for MISO. This option assumes that the MEU would pay a $10 per megawatt-hour (MWh) premium to obtain renewable wind power for approximately one-third of their energy needs and that the wind power premium would increase at 3% per year. The market forecast for power was based on a projection of on- and off-peak energy power supply prices for the Minnesota MISO Hub produced by SNL, an industry data provider. Additionally, the power supply included costs for capacity based on the MISO Zone 1 forecast of annual capacity prices.

The advantage of this approach is that the power market typically provides the lowest priced power and it allows the MEU to specify a certain amount of renewable power in its portfolio. The disadvantage of this approach is that it does not provide any protection against price spikes that have occurred in the market during periods of high demand (summer) or congestion related price increases. Therefore, the MEU is subject to potential wide swings in its power costs. While the MEU could purchase options/hedges to decrease the potential for price volatility, this would increase the average price for power. We have not assumed any "transactional" costs in this power supply option, such as market administration costs; these costs may need to be investigated if the City selects to move forward with its municipalization efforts.

The "all-requirements" JAA/G&T option assumes that all energy (and capacity) would be purchased from a single provider. For this assessment, we have not specifically requested proposals from JAAs or G&Ts. We have estimated wholesale power prices based on our experience with other municipal entities in the region. For the JAA/G&T contract purchases, we have assumed a capacity price of $12 per kilowatt (kW) and an energy price of $50 per MWh, for an average wholesale rate of approximately $69.70 per MWh, based on our experience in the region. The average wholesale power rate for the partial requirements purchases is assumed to increase at the estimated rate of inflation of 2.1% over the Feasibility Study Period. The advantage of this option is that it provides some level of price certainty and reduces the risk for wide swings in power supply costs. The disadvantage is that it locks the MEU into a long-term contract that may be at a significantly higher price than the market offers. Additionally, this option may reduce the degree to which the MEU may be able to specify the amount of renewable energy in its power supply portfolio.

The "combination" power supply options assumes that 30% of the power supply expenses would be from the JAA/G&T (a partial requirement contract) and 70% would be from market purchases. The advantage of this approach is that it offers the MEU some price certainty for its power costs while allowing it to take advantage of lower market prices. This combination may not represent the actual combination of power market/partial requirements the MEU eventually determines is in its best interest for power supply. Additional analysis may be required to determine an optimum combination of power supply costs.

A summary of the power market supply options evaluated for this analysis is provided in Table 2-3 below.

Table 2-3
Estimated Power Supply Costs ($/MWh) (1)

Year	Market Prices (Option 1)	JAA/G&T Prices (Option 2)	Combined Price (2) (Option 3)
2018	$25.74	$69.70	$38.93
2019	$27.61	$71.16	$40.68
2020	$27.81	$72.66	$41.27
2021	$28.70	$74.18	$42.35
2022	$31.89	$75.74	$45.05
2023	$34.83	$77.33	$47.58
2024	$36.34	$78.96	$49.13
2025	$36.68	$80.62	$49.86
2026	$37.93	$82.31	$51.25
2027	$39.56	$84.04	$52.90

(1) Estimated prices based on combination of professional experience and market published data. See text.
(2) Based on 70% market purchases and 30% JAA/G&T contract purchases.

Transmission Costs

The transmission expenses were estimated utilizing a published rate for ITC Midwest, LLC (a regional transmission services provider) of $10.16 per kW for "all-in" transmission service. The all-in transmission service includes all transmission related costs, including scheduling, balancing load, and other elements. This average cost was assumed to increase at the general rate of inflation of 2.1% per year over the Study Period. This cost was applied to the estimated annual demand for the MEU to derive a total cost for transmission services (similar to energy, we have assumed the annual demand stays constant over the Study Period). It has been reported that ITC Midwest rates are significantly higher than other transmission service providers in the region. Future analysis of alternative transmission options may be warranted if the City elects to move forward with this effort (see Risks and Opportunities section).

Utility Operating Costs

The MEU operating costs include distribution expenses (associated with O&M of the locally owned distribution system), customer expense (associated with billing and managing customer accounts), A&G expenses (A&G cost associated with management and other expenses), and other charges. The costs for these operational requirements were estimated to be approximately $1.4 million annually based on our experience with municipal utilities of similar sizes in the Midwest region. Approximately 50% of these costs are allocated to the distribution function, 20% to the customer function, and 30% to the A&G function. These costs are estimated to increase at the annual rate of inflation of 2.1%.

For the purposes of this analysis, it is assumed that the MEU would contract with a nearby utility to provide distribution O&M services for the duration of the Feasibility Study. This may be an economically efficient way to manage the system with experienced personnel while the MEU determines how and when it would hire and train its own staff. We have assumed that a nearby utility would require a fee to provide these services of 15% of the allocated distribution expenses. The MEU would need to evaluate the trade-off between continuing to pay the O&M fee and providing its own staff for the services at a future date.

An additional operating expense is associated with the anticipated roll-out of Energy Efficiency/Demand Side Management (EE/DSM) programs by the MEU. Specific programs/projects were not identified at this level of analysis; however, the financial model includes dedicating 5% of the estimated operating revenue (sales revenue) to EE/DSM programs. This equates to an average of approximately $650,000 per year over the Study Period.

General Fund Transfer

For the purposes of this analysis, it is assumed that once it is operational, the MEU would provide a monetary transfer to the City's general fund. These transfers are often referred to as Payments In-Lieu of Taxes (PILOT or ILOT) and are common in the municipal electric industry. They typically represent the amount of money that an average City would receive if an investor owned utility provided service and was responsible for paying a combination of franchise fees, property taxes, sales taxes, and income taxes (as appropriate). For this analysis, we have assumed that the general fund transfer would represent 5% of operating revenue (sales revenue) on an annual basis, which would equate to an average transfer of approximately $650,000 to the City. The 5% represents a typical transfer rate based on industry experience.

Other Non-Operating Expenses

The financial model includes other non-operating expenses, including investments in the system, debt service for system acquisition and start-up, and funding of operating reserves. Investments in the system are referred to as "renewals and replacements" or normal capital expenditures and are assumed to be equal to approximately $1/15^{th}$ of the RCNLD costs for the system, or $339,000 annually. The system debt services are based on a 20-year bond issue for the acquisition at the taxable rate of 5.0%. The startup debt service is based on a 20-year bond issues for the startup costs at a tax-free rate of 3.5%. The operating reserves are assumed to be equal to the difference between the cash available for debt service and the total non-operating expenses, assuming a desired debt coverage ratio of at least 2.0x. The 2.0x represents a conservative estimate of the coverage ratio required by lending institutions for municipal debt and is applied to the debt service for both the acquisition and startup costs.

Total Revenue Requirement/Average System Rate

The financial model determines the revenue requirement (the total dollars needed to support the MEU) based on the individual expenses identified above. The revenue to be recovered from rates is equal to the revenue requirement of the utility. The average system rate is equal to the revenue requirement divided by the total energy (kWh sales) to determine a $/kWh. This rate would not necessarily be equal to the rates charged by the MEU for its customer classes, as rates would be based on a cost of service analysis upon creation of the MEU. Because different customers place different demands and use power at different times, the rate design of the MEU would need to be tailored to assure that rates were cost based for each customer class, or adjusted to fit specific policy requirements of the City.

The average system rate is a metric utilized to compare the potential costs of operating the MEU to the costs of continuing to obtain service from Alliant/IPL. The average system costs for Alliant/IPL were estimated based on our assessment of average bills from existing customers, including those in the large commercial, small commercial and residential classes, as described in Section 1 of this report. The total bill analysis included adjustments for estimated composition of customers within the City (between customer classes), existing rate riders on Alliant/IPL bills (for transmission service, taxes, etc.) as well as the future rate increases proposed by Alliant/IPL in their pending rate case before the IUB. The average system retail rate for Decorah Alliant/IPL was estimated to increase at the estimated annual rate of 2.1% over the Study Period, based on an estimate of general inflation.

A summary of the projected average system retail rates for the MEU compared to those estimated for Alliant/IPL is provided in Table 2-4 below. The Option 1 (Market Power Supply) results in an estimated savings per year of approximately $7.5 million from the estimated revenue requirement for Alliant/IPL (for year 1 of the Study). Option 2 (Full Requirements) results in an estimated savings per year of approximately $1.1 million, relative to Alliant/IPL in the first year. Option 3 (Combination) results in an estimated savings per year of approximately $5.3 million, relative to Alliant/IPL for the first year.

Table 2-4
Average System Retail Rate Comparison ($/kWh)

Year	Option 1: MEU Market Power Supply (1)	Option 2: MEU JAA/G&T Power Supply (2)	Option 3: MEU 70/30 Combination Power Supply (3)	Projected Decorah Alliant/IPL	Difference between Alliant/IPL and MEU Option 3(4)
2018	$0.0732	$0.1243	$0.0908	$0.1331	($0.0423)
2019	$0.0761	$0.1266	$0.0934	$0.1359	($0.0425)
2020	$0.0770	$0.1291	$0.0947	$0.1388	($0.0441)
2021	$0.0788	$0.1316	$0.0967	$0.1417	($0.0450)
2022	$0.0832	$0.1341	$0.1006	$0.1447	($0.0441)
2023	$0.0873	$0.1367	$0.1043	$0.1477	($0.0434)
2024	$0.0899	$0.1393	$0.1070	$0.1508	($0.0438)
2025	$0.0910	$0.1420	$0.1087	$0.1540	($0.0453)
2026	$0.0933	$0.1448	$0.1112	$0.1572	($0.0460)
2027	$0.0960	$0.1476	$0.1141	$0.1605	($0.0464)

(1) Market Purchases with wind component
(2) All Requirements (JAA/G&T)
(3) Combination of 1 and 2
(4) Difference between Alliant/IPL estimated and Combination Power Supply Option 3 (see text)

Annual Savings

As indicated in Table 2-4 above, under all three power supply options, the estimated MEU average retail rate is lower than the estimated Decorah Alliant/IPL average retail rate for all years of the Study Period. On an annual basis, the savings estimated to be accrued to the MEU is the difference between the average retail rate times the total load. For the table below, it is assumed the MEU would obtain wholesale power supply under the “combination power supply” option (Option 3), described herein.

As indicated herein, the total load is estimated to be held constant over the Study Period. Increases in load due to growth are estimated to be off-set by increased energy efficiency, as well as increased distributed generation (i.e. solar PV). The analysis suggests that the annual MEU revenues would be lower than the similar value for Alliant/IPL for each year of the Study Period. Table 2-5 provides a summary of the estimated annual revenues for year 1 (2018) and year 10 (2027) of the Study for the Greater Decorah MEU and for the portion of the Alliant/IPL system that serves Decorah and surrounding areas.

Table 2-5
Annual Savings Analysis

Item	Year 1 (2018)	Year 10 (2027)
Total Annual Sales (kWh)	126,078,269	126,078,269
Decorah MEU Average Rate ($/kWh)	$0.09080	$0.11410
Total Decorah MEU Revenue	$11,447,907	$14,385,531
Decorah Alliant/IPL Average Rate ($/kWh)	$0.13310	$0.16050
Total Decorah Alliant/IPL Revenue	$16,781,018	$20,235,562
Difference between Decorah MEU and Alliant/IPL Revenue (Savings)	($5,333,111)	($5,850,032)
% Difference	(31.8%)	(28.9%)

Risks and Opportunities for Consideration

Several risks and opportunities for future consideration were recognized in this analysis. Specifically, Luther College has a significant electric load that is within the City limits. Luther College also has a significant investment in a PV array and is served under the Alliant/IPL Net Energy Metering tariff. For the purposes of this analysis, the impact of Luther College and its on-site solar generation is included, as energy sales to Luther College assume the continuation of its on-site solar PV generation. Additionally, net load was assumed to be equal to the average load per customer for residential and small commercial customers as reported by Alliant/IPL. If the City selects to move forward, the NewGen Project Team would recommend specific investigation and analysis regarding solar PV systems within the Greater Decorah MEU as they apply to the entire MEU load.

There may be other transmission options available to the MEU, including potentially connecting to the nearby systems. Our analysis includes an estimate of the costs for transmission service based on the published tariff for ITC. It may be beneficial to the MEU to investigate either purchasing or investing in transmission rights or assets to link nearby JAA/G&T and/or other entities to the Decorah Substation. Additional analysis of these transmission options may be conducted if the City elects to move forward with municipalization.

The NewGen Project Team has assumed that any reduction in load from the MEU EE programs, as well as generation from existing or future distributed solar PV systems, will off-set any potential increases in energy usage over the Study period. Further, the NewGen Project Team has not included any ancillary financial benefits nor impacts of such benefits to the local Decorah economy. Decorah Power has included a discussion of local economic impacts in its report. These impacts may be important to quantify if the City selects to move forward with this effort.

Section 3
CONCLUSIONS AND RECOMMENDATIONS

The NewGen Project Team investigated the technical and financial feasibility of creating a locally owned electric utility (MEU) for the City. This would require the City to acquire the existing electric distribution assets of the incumbent utility, Alliant/IPL. This would also require the City to procure wholesale power, manage and maintain the local distribution system, and bill customers for their power usage. As a result of the field investigations, the NewGen Project Team has determined that it would be in the public interest for the MEU to serve beyond the municipal boundaries of the City (the Greater MEU service territory), which would include essentially all Alliant/IPL customers currently served from the Decorah Substation.

The results of the analysis conducted for this Feasibility Study suggest that on an average system retail rate basis, a Greater Decorah MEU could provide service to its customers for a lower cost while providing reliable power, increased renewable energy, and local energy management programs. The analysis relies on a series of assumptions with regard to the acquisition of the Alliant/IPL assets, the costs to acquire wholesale power supply, as well as the costs to operate and maintain the MEU. Each of these assumptions requires additional investigation prior to the development of an application for municipalization to be filed with the IUB. However, as indicated herein, the NewGen Project Team and Decorah Power have included various options and conservatism in these underlying assumptions, including no load growth, taxable debt (for acquisition costs), and funding for energy efficiency contributions at levels higher than Alliant/IPL currently provide, among others.

Primary drivers for the average MEU system retail rates include the assumptions and estimates for the costs to acquire the system assets, the future power supply expenses, and other operating costs. For this assessment, the NewGen Project Team has made reasonable estimates and assumptions consistent with this Feasibility Study. If the City selects to move forward with its municipalization of the Alliant/IPL assets, we would recommend additional investigations into these assumptions and estimates to further refine the average retail rate comparison.

Appendix A
Financial Analysis Scenarios

The following provides a summary of the estimated cash flow projections from the MEU for the three power supply options discussed in the text above.

Scenario 1 – Market Price with Renewable (Wind)

Decorah, IA Municipalization - Pro Forma Financial Analysis

Line	Item			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1	**Operating Revenues**			$ 9,231	$ 9,591	$ 9,709	$ 9,929	$ 10,487	$ 11,012	$ 11,329	$ 11,477	$ 11,760	$ 12,100
2	**Projected Operating Expense**												
3	Power Supply Expense	Market + Wind	Input Scenario	$ 3,391	$ 3,638	$ 3,665	$ 3,782	$ 4,202	$ 4,589	$ 4,788	$ 4,833	$ 4,998	$ 5,212
4	Transmission Expense	ITC Midwest	Input Scenario	2,198	2,244	2,291	2,339	2,388	2,438	2,489	2,542	2,595	2,650
5	Distribution Expense	50%	% Assumed Dist, Cust, A&G O&M	700	715	730	745	761	777	793	810	827	844
6	Customer Expense	20%	% Assumed Dist, Cust, A&G O&M	280	286	292	298	304	311	317	324	331	338
7	General and Administrative Expense	30%	% Assumed Dist, Cust, A&G O&M	420	429	438	447	456	466	476	486	496	506
8	O&M Fee	15%	of Dist O&M	105	107	109	112	114	116	119	121	124	127
9	EE/DSM Programs	5.0%	of Operating Revenue	462	480	485	496	524	551	566	574	588	605
10	**Total Operating Expenses**			$ 7,555	$ 7,898	$ 8,010	$ 8,219	$ 8,749	$ 9,248	$ 9,549	$ 9,690	$ 9,958	$ 10,281
11	General Fund Transfer (5.0% of Gross Revenue)	5.0%	of Gross Rate Revenue	$ 462	$ 480	$ 485	$ 496	$ 524	$ 551	$ 566	$ 574	$ 588	$ 605
12	**Available for Debt Service**			$ 1,214	$ 1,214	$ 1,214	$ 1,214	$ 1,214	$ 1,214	$ 1,214	$ 1,214	$ 1,214	$ 1,214
13	Renewals and Replacements (15 year Asset Life)	15	Years Asset Life	$ 339	$ 339	$ 339	$ 339	$ 339	$ 339	$ 339	$ 339	$ 339	$ 339
14	System Debt Service			446	446	446	446	446	446	446	446	446	446
15	Startup Cost Debt Service			160	160	160	160	160	160	160	160	160	160
16	**Total Non-Operating Expense**			$ 946	$ 946	$ 946	$ 946	$ 946	$ 946	$ 946	$ 946	$ 946	$ 946
17	Margin/Operating Reserves			$ 268	$ 268	$ 268	$ 268	$ 268	$ 268	$ 268	$ 268	$ 268	$ 268
18	**Debt Service Coverage Ratio**	2.00	Debt Service Coverage Ratio	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
19	**Total Revenue Requirement - MEU**			$ 9,231	$ 9,591	$ 9,709	$ 9,929	$ 10,487	$ 11,012	$ 11,329	$ 11,477	$ 11,760	$ 12,100
20	**Revenue at IPL Rates**			$ 16,781	$ 17,134	$ 17,500	$ 17,865	$ 18,244	$ 18,622	$ 19,013	$ 19,416	$ 19,820	$ 20,236
21	**%-difference**			-45%	-44%	-45%	-44%	-43%	-41%	-40%	-41%	-41%	-40%
22	**Total Rev Req/Total MWh Sales**			$ 73.21	$ 76.07	$ 77.01	$ 78.75	$ 83.18	$ 87.34	$ 89.85	$ 91.03	$ 93.27	$ 95.97
23	**Power Supply Expense/MWh**			$ 26.90	$ 28.86	$ 29.07	$ 30.00	$ 33.32	$ 36.40	$ 37.98	$ 38.34	$ 39.64	$ 41.34
24	**Rev Req (less PP)/Total MWh Sales**			$ 46.31	$ 47.22	$ 47.94	$ 48.76	$ 49.86	$ 50.94	$ 51.88	$ 52.70	$ 53.63	$ 54.63
25	**Average MEU Rate ($/kWh)**			$ 0.0732	$ 0.0761	$ 0.0770	$ 0.0788	$ 0.0832	$ 0.0873	$ 0.0899	$ 0.0910	$ 0.0933	$ 0.0960
26	**Average IPL Rate ($/kWh)**			$ 0.1331	$ 0.1359	$ 0.1388	$ 0.1417	$ 0.1447	$ 0.1477	$ 0.1508	$ 0.1540	$ 0.1572	$ 0.1605
27	**Difference ($/kWh)**			$ (0.0599)	$ (0.0598)	$ (0.0618)	$ (0.0629)	$ (0.0615)	$ (0.0604)	$ (0.0609)	$ (0.0630)	$ (0.0639)	$ (0.0645)

NewGen Strategies & Solutions

Scenario 2 – Full Requirements JAA/G&T

Decorah, IA Municipalization - Pro Forma Financial Analysis

Line	Item			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1	**Operating Revenues**			$ 15,666	$ 15,967	$ 16,274	$ 16,587	$ 16,907	$ 17,234	$ 17,567	$ 17,908	$ 18,256	$ 18,611
2	**Projected Operating Expense**												
3	Power Supply Expense	All Requirements (JAA/G&T)	Input Scenario	$ 9,183	$ 9,376	$ 9,573	$ 9,774	$ 9,979	$ 10,189	$ 10,403	$ 10,621	$ 10,844	$ 11,072
4	Transmission Expense	ITC Midwest	Input Scenario	2,198	2,244	2,291	2,339	2,388	2,438	2,489	2,542	2,595	2,650
5	Distribution Expense	50%	% Assumed Dist, Cust, A&G O&M	700	715	730	745	761	777	793	810	827	844
6	Customer Expense	20%	% Assumed Dist, Cust, A&G O&M	280	286	292	298	304	311	317	324	331	338
7	General and Administrative Expense	30%	% Assumed Dist, Cust, A&G O&M	420	429	438	447	456	466	476	486	496	506
8	O&M Fee	15%	of Dist O&M	105	107	109	112	114	116	119	121	124	127
9	EE/DSM Programs	5.0%	of Operating Revenue	783	798	814	829	845	862	878	895	913	931
10	**Total Operating Expenses**			$ 13,669	$ 13,955	$ 14,246	$ 14,544	$ 14,848	$ 15,159	$ 15,475	$ 15,799	$ 16,129	$ 16,467
11	General Fund Transfer (5.0% of Gross Revenue)	5.0%	of Gross Rate Revenue	$ 783	$ 798	$ 814	$ 829	$ 845	$ 862	$ 878	$ 895	$ 913	$ 931
12	**Available for Debt Service**			$ 1,214	$ 1,214	$ 1,214	$ 1,214	$ 1,214	$ 1,214	$ 1,214	$ 1,214	$ 1,214	$ 1,214
13	Renewals and Replacements (15 year Asset Life)	15	Years Asset Life	$ 339	$ 339	$ 339	$ 339	$ 339	$ 339	$ 339	$ 339	$ 339	$ 339
14	System Debt Service			446	446	446	446	446	446	446	446	446	446
15	Startup Cost Debt Service			160	160	160	160	160	160	160	160	160	160
16	**Total Non-Operating Expense**			$ 946	$ 946	$ 946	$ 946	$ 946	$ 946	$ 946	$ 946	$ 946	$ 946
17	Margin/Operating Reserves			$ 268	$ 268	$ 268	$ 268	$ 268	$ 268	$ 268	$ 268	$ 268	$ 268
18	**Debt Service Coverage Ratio**	2.00	Debt Service Coverage Ratio	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
19	**Total Revenue Requirement - MEU**			$ 15,666	$ 15,967	$ 16,274	$ 16,587	$ 16,907	$ 17,234	$ 17,567	$ 17,908	$ 18,256	$ 18,611
20	**Revenue at IPL Rates**			$ 16,781	$ 17,134	$ 17,500	$ 17,865	$ 18,244	$ 18,622	$ 19,013	$ 19,416	$ 19,820	$ 20,236
21	**%-difference**			-7%	-7%	-7%	-7%	-7%	-7%	-8%	-8%	-8%	-8%
22	**Total Rev Req/Total MWh Sales**			$ 124.26	$ 126.64	$ 129.08	$ 131.56	$ 134.10	$ 136.69	$ 139.34	$ 142.04	$ 144.80	$ 147.61
23	**Power Supply Expense/MWh**			$ 72.84	$ 74.37	$ 75.93	$ 77.52	$ 79.15	$ 80.81	$ 82.51	$ 84.24	$ 86.01	$ 87.82
24	**Rev Req (less PP)/Total MWh Sales**			$ 51.42	$ 52.27	$ 53.15	$ 54.04	$ 54.95	$ 55.88	$ 56.83	$ 57.80	$ 58.79	$ 59.79
25	**Average MEU Rate ($/kWh)**			$ 0.1243	$ 0.1266	$ 0.1291	$ 0.1316	$ 0.1341	$ 0.1367	$ 0.1393	$ 0.1420	$ 0.1448	$ 0.1476
26	**Average IPL Rate ($/kWh)**			$ 0.1331	$ 0.1359	$ 0.1388	$ 0.1417	$ 0.1447	$ 0.1477	$ 0.1508	$ 0.1540	$ 0.1572	$ 0.1605
27	**Difference ($/kWh)**			$ (0.0088)	$ (0.0093)	$ (0.0097)	$ (0.0101)	$ (0.0106)	$ (0.0110)	$ (0.0115)	$ (0.0120)	$ (0.0124)	$ (0.0129)

Scenario 3 – Combination of 70% Market Price / 30% Partial Requirements JAA/G&T

Decorah, IA Municipalization - Pro Forma Financial Analysis

Line	Item			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1	**Operating Revenues**			$ 11,445	$ 11,772	$ 11,937	$ 12,189	$ 12,688	$ 13,156	$ 13,494	$ 13,705	$ 14,014	$ 14,382
2	**Projected Operating Expense**												
3	Power Supply Expense	Partial Req. (JAA/G&T) + Mkt	Input Scenario	$ 5,384	$ 5,601	$ 5,670	$ 5,815	$ 6,182	$ 6,519	$ 6,737	$ 6,839	$ 7,027	$ 7,266
4	Transmission Expense	ITC Midwest	Input Scenario	2,198	2,244	2,291	2,339	2,388	2,438	2,489	2,542	2,595	2,650
5	Distribution Expense	50%	% Assumed Dist, Cust, A&G O&M	700	715	730	745	761	777	793	810	827	844
6	Customer Expense	20%	% Assumed Dist, Cust, A&G O&M	280	286	292	298	304	311	317	324	331	338
7	General and Administrative Expense	30%	% Assumed Dist, Cust, A&G O&M	420	429	438	447	456	466	476	486	496	506
8	O&M Fee	15%	of Dist O&M	105	107	109	112	114	116	119	121	124	127
9	EE/DSM Programs	5.0%	of Operating Revenue	572	589	597	609	634	658	675	685	701	719
10	**Total Operating Expenses**			$ 9,659	$ 9,970	$ 10,127	$ 10,366	$ 10,840	$ 11,284	$ 11,606	$ 11,806	$ 12,100	$ 12,449
11	General Fund Transfer (5.0% of Gross Revenue)	5.0%	of Gross Rate Revenue	$ 572	$ 589	$ 597	$ 609	$ 634	$ 658	$ 675	$ 685	$ 701	$ 719
12	**Available for Debt Service**			$ 1,214	$ 1,214	$ 1,214	$ 1,214	$ 1,214	$ 1,214	$ 1,214	$ 1,214	$ 1,214	$ 1,214
13	Renewals and Replacements (15 year Asset Life)	15	Years Asset Life	$ 339	$ 339	$ 339	$ 339	$ 339	$ 339	$ 339	$ 339	$ 339	$ 339
14	System Debt Service			446	446	446	446	446	446	446	446	446	446
15	Startup Cost Debt Service			160	160	160	160	160	160	160	160	160	160
16	**Total Non-Operating Expense**			$ 946	$ 946	$ 946	$ 946	$ 946	$ 946	$ 946	$ 946	$ 946	$ 946
17	Margin/Operating Reserves			$ 268	$ 268	$ 268	$ 268	$ 268	$ 268	$ 268	$ 268	$ 268	$ 268
18	**Debt Service Coverage Ratio**	2.00	Debt Service Coverage Ratio	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
19	**Total Revenue Requirement - MEU**			$ 11,445	$ 11,772	$ 11,937	$ 12,189	$ 12,688	$ 13,156	$ 13,494	$ 13,705	$ 14,014	$ 14,382
20	**Revenue at IPL Rates**			$ 16,781	$ 17,134	$ 17,500	$ 17,865	$ 18,244	$ 18,622	$ 19,013	$ 19,416	$ 19,820	$ 20,236
21	**%-difference**			-32%	-31%	-32%	-32%	-30%	-29%	-29%	-29%	-29%	-29%
22	**Total Rev Req/Total MWh Sales**			$ 90.77	$ 93.37	$ 94.68	$ 96.68	$ 100.64	$ 104.35	$ 107.03	$ 108.70	$ 111.15	$ 114.07
23	**Power Supply Expense/MWh**			$ 42.70	$ 44.43	$ 44.97	$ 46.13	$ 49.03	$ 51.70	$ 53.43	$ 54.24	$ 55.73	$ 57.63
24	**Rev Req (less PP)/Total MWh Sales**			$ 48.07	$ 48.95	$ 49.71	$ 50.55	$ 51.60	$ 52.64	$ 53.60	$ 54.46	$ 55.42	$ 56.44
25	**Average MEU Rate ($/kWh)**			$ 0.0908	$ 0.0934	$ 0.0947	$ 0.0967	$ 0.1006	$ 0.1043	$ 0.1070	$ 0.1087	$ 0.1112	$ 0.1141
26	**Average IPL Rate ($/kWh)**			$ 0.1331	$ 0.1359	$ 0.1388	$ 0.1417	$ 0.1447	$ 0.1477	$ 0.1508	$ 0.1540	$ 0.1572	$ 0.1605
27	**Difference ($/kWh)**			$ (0.0423)	$ (0.0425)	$ (0.0441)	$ (0.0450)	$ (0.0441)	$ (0.0434)	$ (0.0438)	$ (0.0453)	$ (0.0460)	$ (0.0464)