TOWN OF LYONS, COLORADO

ELECTRIC SYSTEM COST OF SERVICES STUDY

CDBG-DR-RD2P-ELEC RATES EPSIM

DECEMBER 08, 2016

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III. EXECUTIVE SUMMARY

Since 1974, the Town of Lyons has owned and operated its own electric retail distribution utility. The Town entered into a Total Requirements contract with the Municipal Energy Agency of Nebraska (MEAN) in 1981, and continues to receive its wholesale electricity under this agreement. The Town is interconnected to the WAPA transmission grid and receives Firm Electric Service from WAPA's Loveland Area Projects.

The Town experienced three consecutive events that affected its operations:

- 2012: Under-collection of revenues and loss of load.
- 2013: Flood damages and loss of load.
- 2014: Energy and Capacity price increase due to changes in regulations affecting MEAN in the Southwest Power Pool Regional Transmission Organization.

Despite these three back-to-back events, the Town has shown signs of full recovery in 2016. Load increase is being driven by residential customers and the whole Town load is growing again at a forecasted rate between one and three percent annually. The growing load will serve to slow down increases in retail rates.

EPSIM offers three sets of recommendations:

Recommendations on Rates and Operating Reserve:

- Increase 2017 sales revenues by 6.24 percent.
- Budget $50,000 annually (before inflation) for Capital Improvements.

Recommendations which do not require any capital expense:

- Set separate accounts for the utility's restricted funds and for operating reserves.
- Review and update, on a quarterly basis, all costs, revenues, loads, and cash flow, reconciling each against budget.
- Apply for increased WAPA allocation of Firm Energy and Capacity.
- Reconsider Distributed Generation policies, particularly as it pertains to installed capacity allowance and Net-Metering rates.
- Bill the Town for all electricity used by Town-owned properties.
- Start considering the impact of Electric Vehicles on the distribution assets' capacity, on the Town's peak demand, and on the cost/revenue forecast.

Recommendations which would require moderate investments:

- Access the meter data at the Daugherty substation to analyze demand peaks, shadow-calculate wholesale invoices, and track distribution losses.
- Replace the existing retail meters with interval meters.

IV. INTRODUCTION

The Town of Lyons, Colorado, has contracted EPSIM Corporation to develop a Cost of Services Study and a financial model, based on data and documents received from the Town, the Western Area Power Administration's Rocky Mountain Region, and the Municipal Energy Agency of Nebraska. The following report details the findings and observations, based on historic data between 2006 and 2015, and forecasted data between 2016 and 2026, pertaining to 1) the retail loads, 2) Distributed Generation (photovoltaic solar), 3) wholesale supplies of energy, 4) capacity and transmission, 5) revenues on accrual and cash basis, 6) operation expenses and capital expenditures, and 7) debt service. Recommendations on operations, financial management and policies conclude the report.

V. UTILITY OPERATIONS: HISTORICAL REVIEW 2006 TO 2015

A. Town's Historical Energy and Demand

1. Town Retail Load: 2006 to 2015

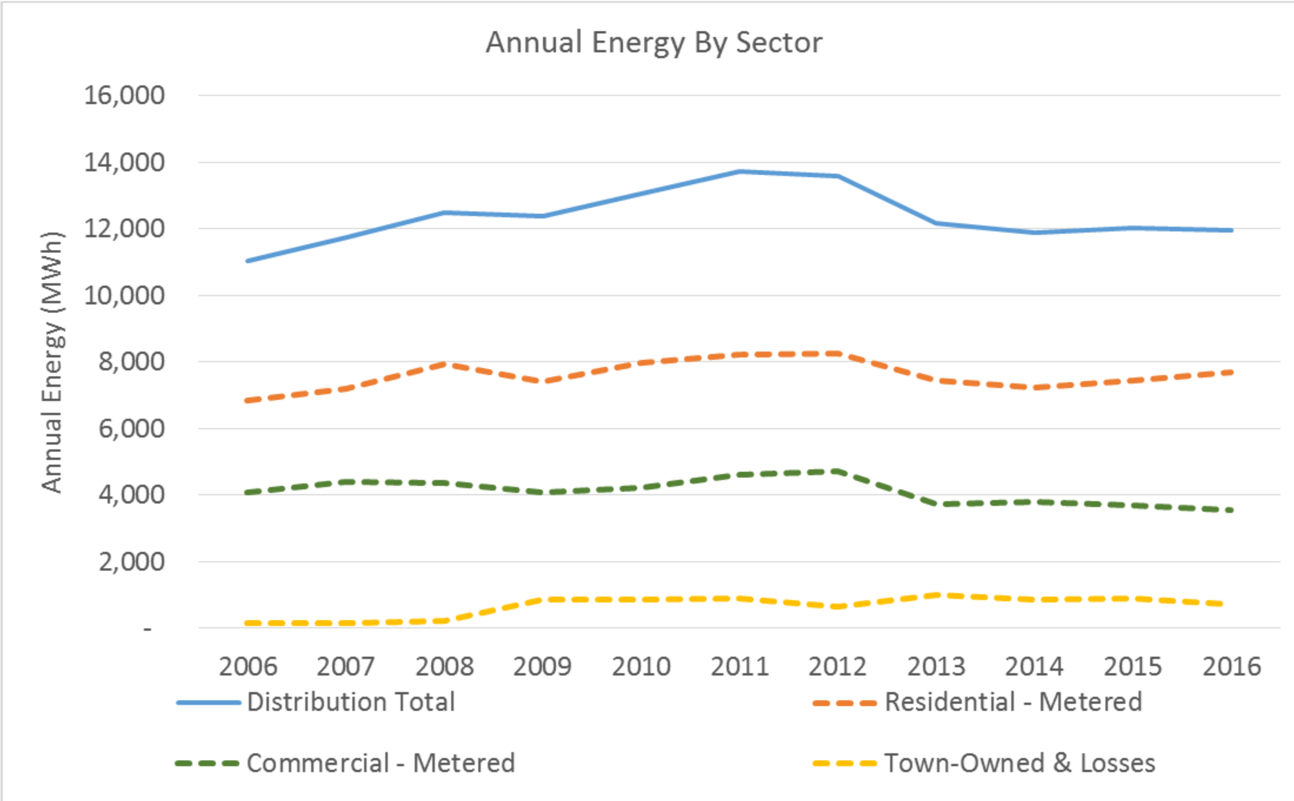
The Town of Lyons, Colorado, has operated its own electric utility since 1974 to serve its residential and business members, as well as Town-Owned loads. The Town procures energy and capacity on the wholesale market, to serve its retail load. The following analysis was developed from historical hourly readings at the Daugherty meter, provided by WAPA-RMR.

From 2006 to 2015, the Town's historical load can be divided into three periods, as depicted by "Distribution Total" energy in Figure 1:

- Until 2011, the load was growing steadily at an annual rate of 4 percent, with a momentary decline in 2009.
- In 2012, the load declined by 1 percent from 2011 and the down trend continued into 2013.
- The third time period starts with the flood of September 2013. Following the catastrophic destruction from the flood, the Town's electric service recovered within 35 days (electric service was restored within 36 hours), but to a "new normal"; the energy level from December 2013 was comparable to that of 2007, due to the reduction in retail load. Some load reduction continued into 2014, then flattened in 2015, and 2016 shows signs of recovery and growth. The recovery appears to be driven by residential customers, while non-residential loads are still on a slight decline[1].

[1] In the absence of retail interval metering, energy by customer class is extrapolated from 2006-2009 annual sales, and demand by customer class is derived from Residential proxy load profiles. See Appendix B for details on methodology used to estimate residential, commercial, and Town-owned loads.

Figure 1: Annual Energy by Customer Class (1 MWh = 1,000 kWh)



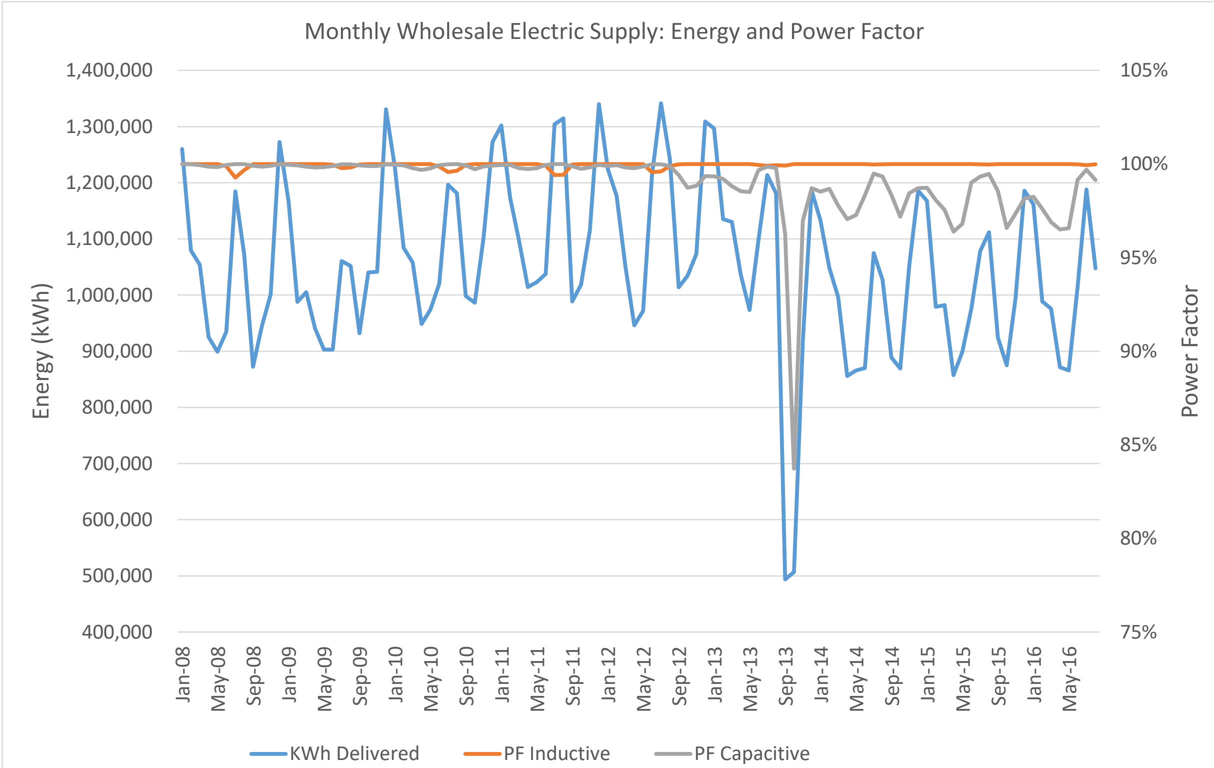
Distribution losses averaged an estimated 5.7 percent of the total load metered at the Daugherty substation between 2009 and 2015. Distribution losses are comprised of the following estimated 2009 – 2015 averages:

• Substation parasitic load[2]:	46,000 kWh/year
• Distribution transformers (η ≈ 97%):	346,000 kWh/year
• Unaccounted for / non-metered loads:	321,000 kWh/year
Total:	*713,000 kWh/year*

Since 2008, the Town's monthly electric energy consumption has oscillated between 900,000 and 1,300,000 kWh, with a summer and a winter peak, as shown in Figure 2. The low energy consumption months are from April to June, and from September to October. The Town's electric consumption peaks naturally in the winter. With the development of summer community events and air-conditioned homes, summer peaks started matching winters' in 2011 and until the flood of 2013. Summer energy peak grew back to match winter peak in 2016.

[2] See "The Flood of 2013" section later in this document

Figure 2: Monthly Wholesale Energy Supply (Left Axis) and Power Factor (Right Axis)



While energy in 2016 has recovered to 2007 levels, overall demand has recovered further - to 2011 levels. Figure 3 shows the annual peak demand metered at the substation, and the estimated peak demand by retail customer class[3,4]. By 2015, residential demand appears to have caught up with 2009 levels, however commercial demand has fallen below 2006 levels.

Assuming no substantial behavioral changes across the utility's customers, this discrepancy between energy and demand growth would be the result of electricity losses in the distribution grid; these losses are distinct from transmission losses. The 321,000 kWh average non-metered loads are equivalent to a 310 kW load running 1,000 hours a year. Such a 300+ kW disparity could explain the discrepancy between growth in energy and growth in demand during the recovery through 2016.

[3] Town-Owned demand does not include unaccounted-for / non-metered distribution losses.
[4] In the absence of retail interval metering, demand by customer class is derived from Residential proxy load profiles. See Appendix B for details on methodology used to estimate residential, commercial, and Town-owned loads.

Figure 3: Maximum Annual Demand by Customer Class

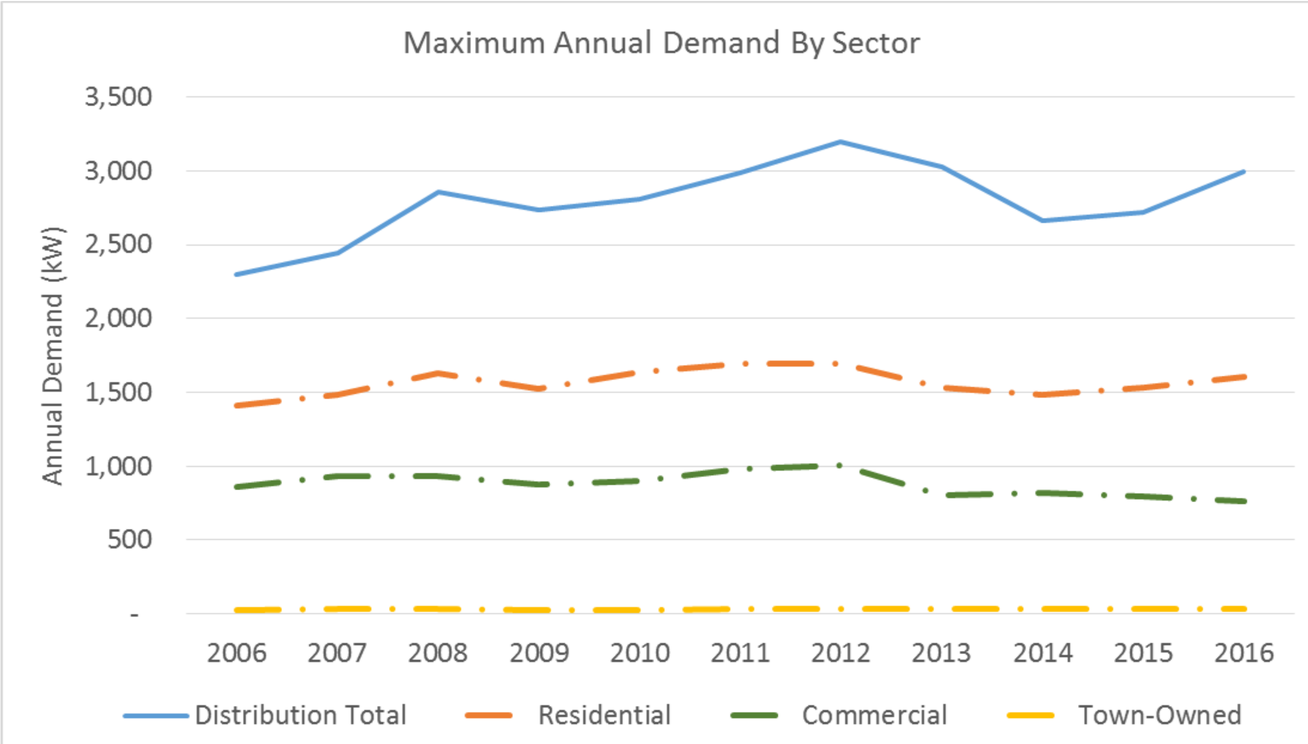
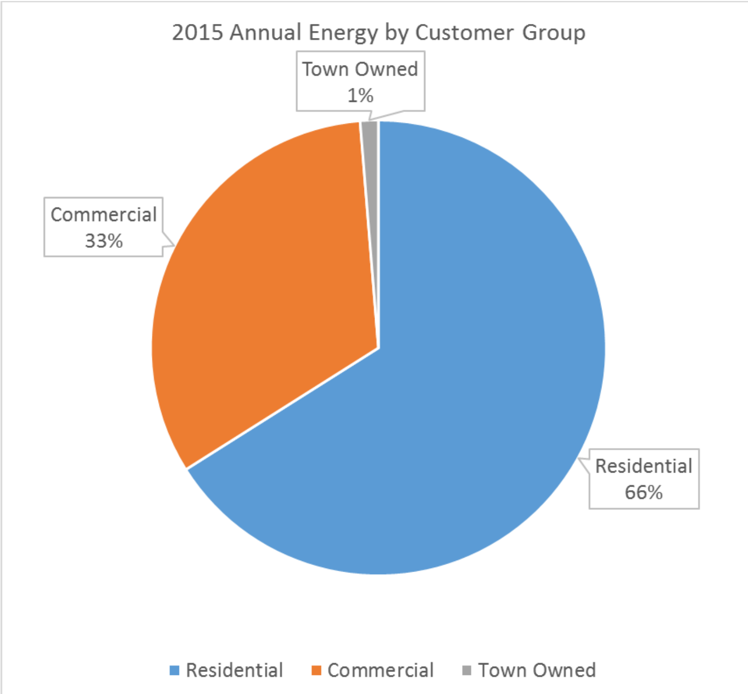


Figure 4 compares the annual energy and peak demand, estimated by customer class, for 2015. The ratio of energy to demand, on an annual basis, appears to be consistent between customer classes. In the absence of customer demand metering, the estimates by customer class are based on proxy data from other utilities and thus speculative. Looking beyond 2016, simulation of increased solar Distributed Energy Generation development for one customer group will reduce its proportional share of energy but not its share of demand.

Figure 4: Estimated 2015 Energy and Peak Demand by Customer Class



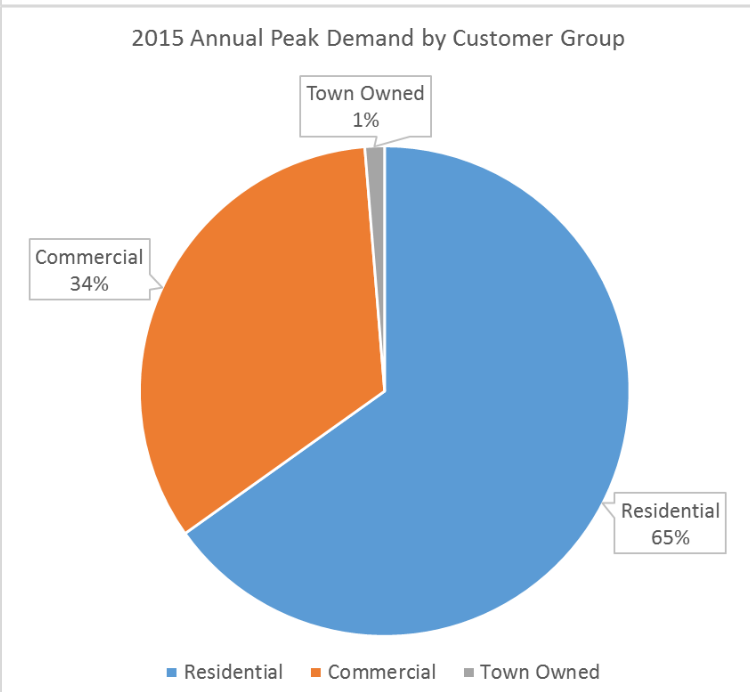
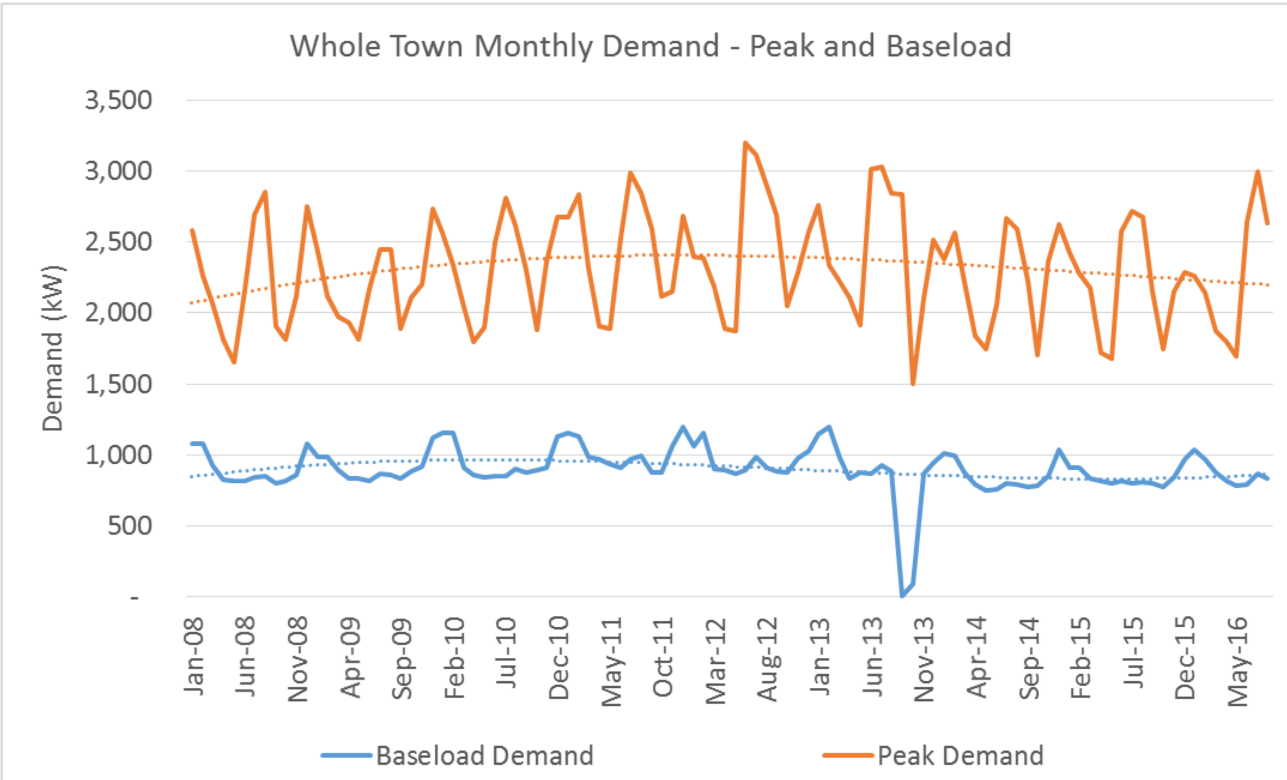


Figure 5 illustrates the maximum monthly demand for the whole Town and its retail customers, as metered at the substation. Monthly demand peaked at a historical 3,200 kW in June 2012. Following a record low demand peak during the winter of 2015, the summer of 2016 appears to show complete recovery of maximum demand. Peak demand can vary by as much as 1,300 kW month to month, as seen between May and June 2012.

Figure 5 also shows the monthly minimum demand, known as baseload, above which the load remains at all times. The whole Town's baseload, including retail customers, has averaged 915 kW since 2008[5] with a narrow +/- 220 kW bandwidth. Further explained in the Figure 6 examples, baseload demand is highest in the winter months and always met between the hours of 1:00 am and 4:00 am.

Figure 5: Monthly Demand - Peak and Baseload

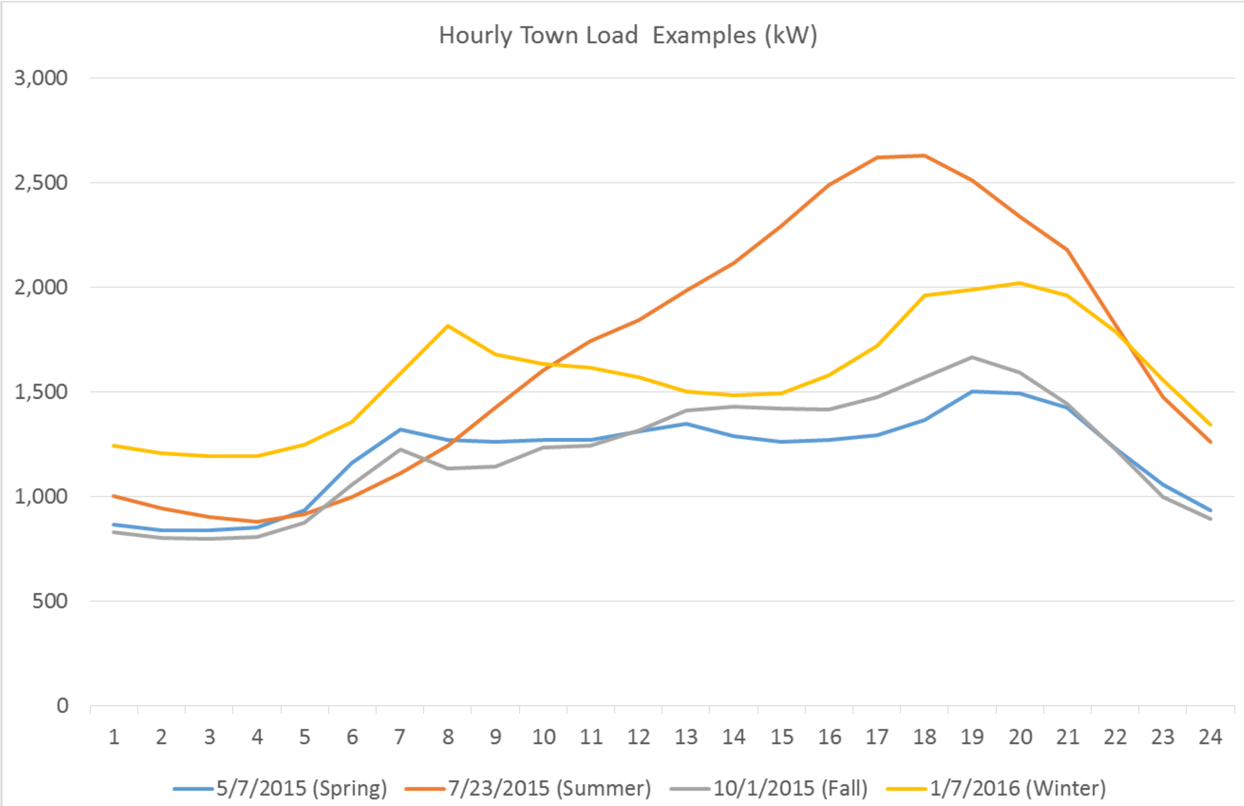


The load aggregate shows three distinct seasonal behaviors, with some variations on weekends, holidays and during unusual weather events. Focusing here on weekdays, Figure 6 illustrates four representative Thursdays in the year. The shoulder seasons (spring and fall) exhibit a relatively flat profile with the minimum load around 3:00 am, a morning peak at 7:00 am and a second peak in the evening at 7:00 pm; spring load dips during the day while fall load tends to grow gradually between the morning and higher evening peaks. Summer load is lowest between 4:00 and 5:00 am, with minimum levels similar to shoulder seasons, and peaks in the evening around 6:00 pm. Winter load exhibits two distinct peaks, at 7:00 am and 7:00 pm (in Daylight Savings Time) with a significant dip during the day; winter minima, however, are higher than other seasons.

The example below shows a summer peak demand being higher than winter, inadvertently due to the choice of weekdays. In reality, winter monthly peaks are generally equivalent to or higher than summer monthly peaks.

[5] Excluding September and October 2013.

Figure 6: Representative Weekday Hourly Load Profiles



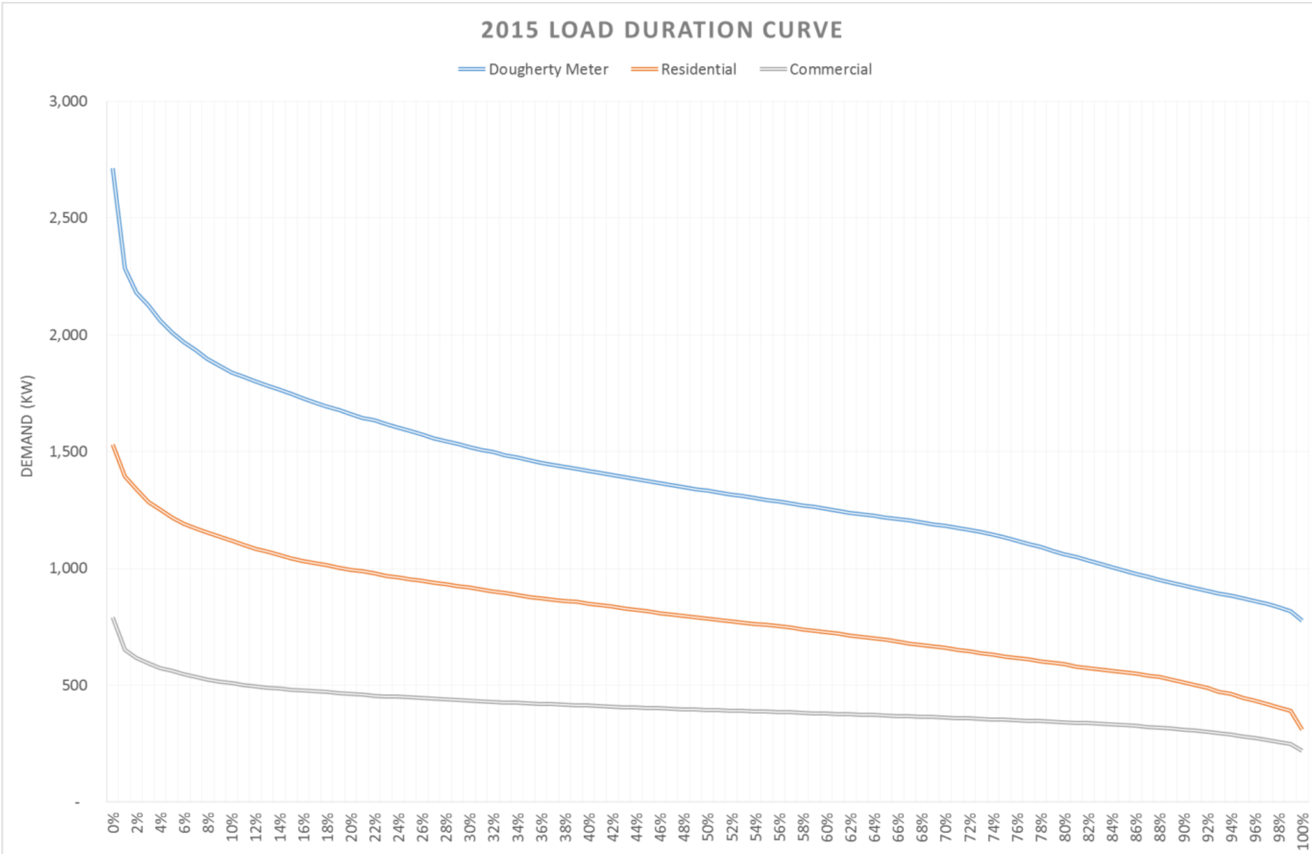
Load Duration Curves, such as the one shown in Figure 7, illustrate the percentage of the time that a load is above a certain power level. The Town's load duration curves, which depict the concentration of hourly loads through the year, exhibit consistent characteristics between 2008 and 2016.

For 2015, a representative year, the load duration curve shows that the top 500 kW demand occurred in the first percentile (88 hours) of the year. The peak demand event registered at the Daugherty Substation meter was 2,715 kW on July 27 at 18:00. The next three high demand events were on August 14 at hours 15:00, 16:00 and 17:00, and the next seven highest demand events occurred between 17:00 and 19:00 between July 23 and 27.

The curve breakdown by residential and commercial customers is based on the overall Town meter readings and a proxy curve for residential consumption profile from nearby utilities. The data is speculative at the customer class level, it is shown for illustration only. Peak demands occur at different times for different customers. They are not expected to add up to the total peak but the sum of customer peaks should exceed the aggregate peak at all percentile levels; Figure 7 indicates there is a missing load category, comprised of Town-Owned and non-metered loads.

The Load Duration Curve can be used as a starting point to evaluate energy efficiency and demand reduction policies: what is the cost of incremental demand in the first percentile and which customer group drives that demand?

Figure 7: Town and Retail Load Duration Curves for 2015

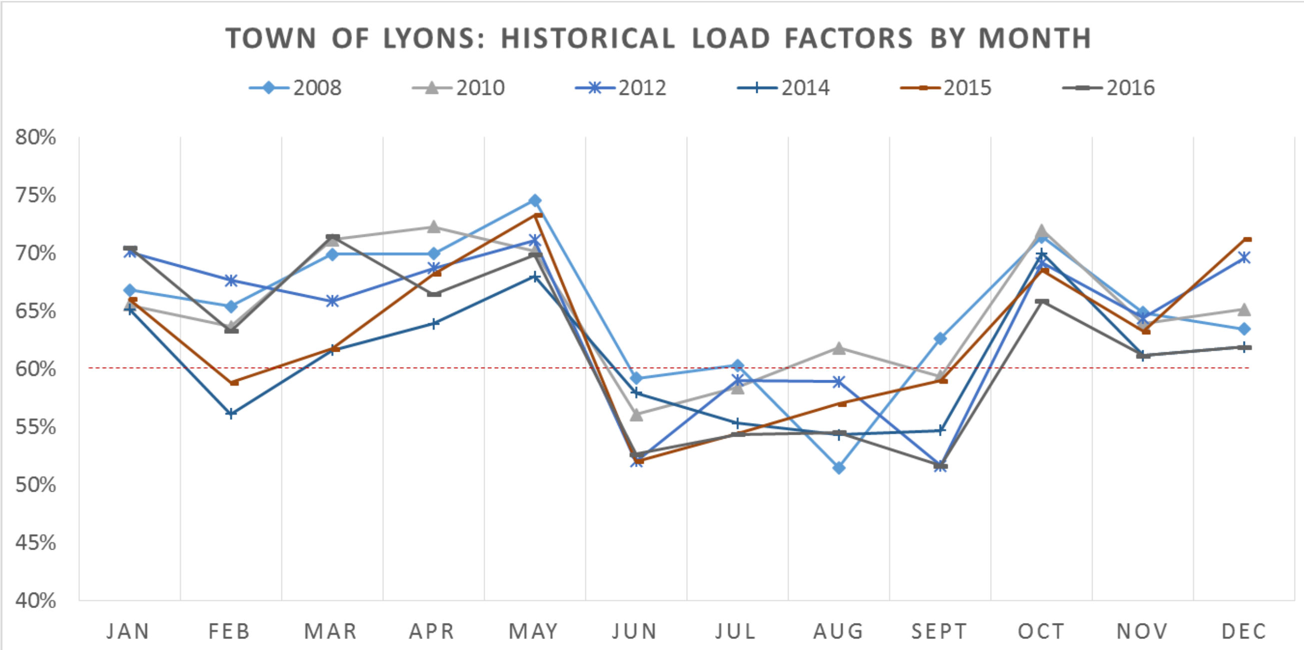


At the right of the Load Duration Curves, at the 100th percentile is the minimum power, or baseload, required by the whole Town (blue line), by the residential accounts (orange line) and by the commercial accounts (grey line).

The examples above lead to another question: how much capacity does the Town load require to serve a day's worth of energy? This can be understood better by employing another metric – Load Factor, which is a measure of the persistency of energy consumption through a given period[6]. Figure 8 highlights the monthly load factors for the total load metered at the substation. Shoulder seasons and, to a lesser extent, winter, show excellent load factors, since the demand remains relatively flat during those days. Summer season, on the other hand, indicates a low load factor, resulting in higher demand – and demand costs - to serve the load's energy.

[6] Monthly Load Factor = metered energy / (peak demand x hours in month)

Figure 8: Monthly Load Factors - Total Load



While load factors are lower in the summer, the Town shows a healthy load factor between October and May. For load factors below 60 percent, the total cost of electricity becomes driven largely by demand costs, which then results in higher net retail rates per kWh. Figure 8 provides supporting evidence for the Town's application of seasonal energy rates.

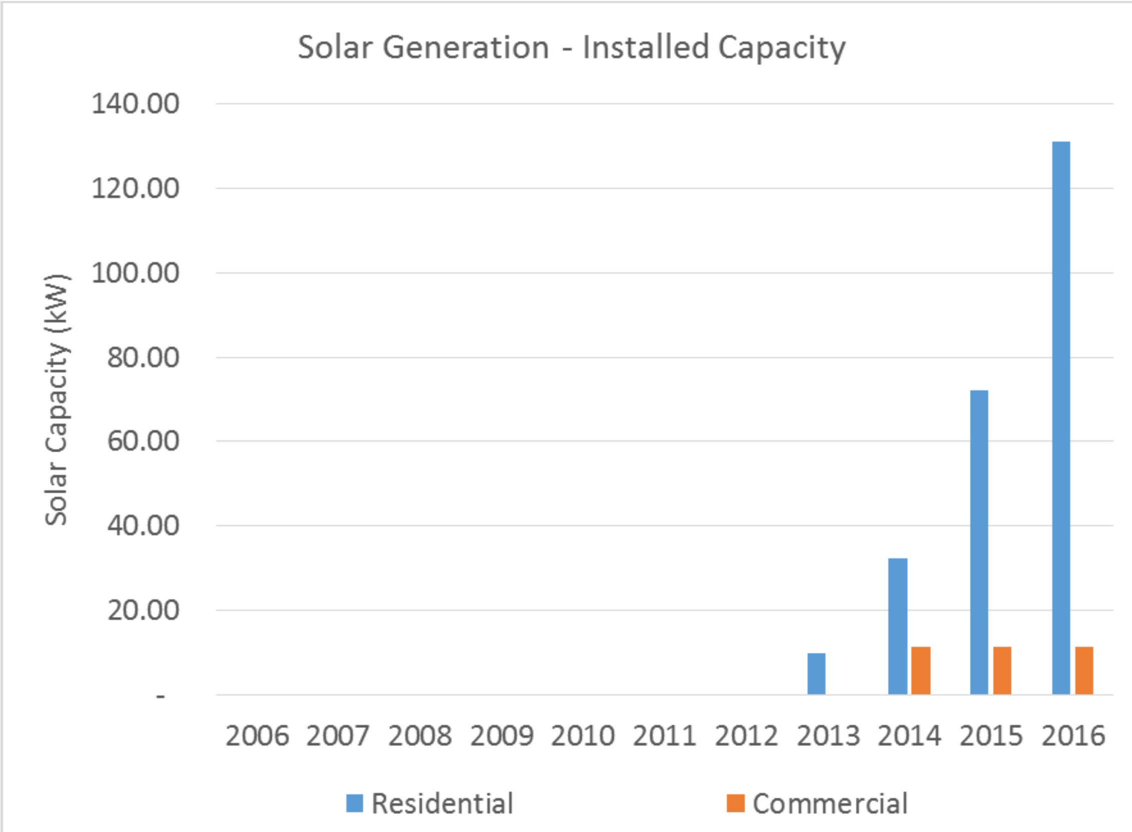
The development of customer-owned solar Distributed Generation is a contributor to decreasing load factor, due to the fact that solar power reduces metered energy but not demand, particularly for residential. For the Town this can be seen by the fact that peak loads occur in the summer evenings, well after the solar generation has dropped off from mid-day maxima. Table 1 shows the installed capacity of Distributed Solar Energy Generation.

Table 1: Installed Solar Capacity (Source: Town of Lyons)

	RESIDENTIAL	COMMERCIAL
2013	9.75 kW	
2014	32.23	11.40 kW
2015	72.06	11.40 kW
2016	131.07	11.40 kW

The rapid increase in residential solar development has seen the cumulative installed capacity double in 2015 and again in 2016. 2013 capacity comes from a single account. The increased capacity in 2014 came from 4 new accounts, averaging 5.62 kW each. In 2015, 9 new accounts installed an average of 4.42 kW each. Finally in 2016, 10 new accounts added an average of 5.90 kW each. The smallest residential installation is 2.28 kW and the largest is 9.75 kW. On the commercial side, the only solar installation to date is an 11.40 kW unit installed in 2014.

Figure 9: Installed Solar Capacity (Source: Town of Lyons)



A last metric of load is reactive energy. The metered active energy, measured in kWh, is only one component of the total apparent energy (in kVA) supplied to the Town by MEAN. The other component is the reactive energy, metered in kVARh and either supplied to - or received from – the Town load. When the Town load is inductive, reactive energy must be delivered from the transmission grid to the Town load; conversely, reactive energy must be sent back to the transmission grid when the Town load is capacitive. The Power Factor is a metric used by industry to quantify any load's deviation from a purely active state. It is a trigonometric relationship between active and reactive energy[7]. Per the Town's contract with MEAN, the Town's Utility must maintain a Power Factor above 95 percent (inductive or reactive) to avoid paying penalties[8].

Historical Power Factors, derived from the substation meter readings, are illustrated in Figure 2 above. Making exception for the 2013 flood event, the Town's Utility maintained a nearly perfect Power Factor until August 2012, at which point the Power Factor started drifting gradually on the capacitive side towards the 95 percent mark. It is an indication that the Town has lost inductive loads, such as electric motors typically found in commercial operations. The Town can correct its average Power Factor by adjusting capacitor banks at its substation. Should

[7] Power Factor: PF = ArcTan(cos(kVARh/kWh)). Penalties are determined by increasing the capacity billed that corresponds to a Power Factor to 95 percent.

[8] Municipal Energy Agency of Nebraska Schedule M Exhibit B: Schedule of Rates. Minimum Power Factor requirement changed from 90 to 95 percent on the Tariff effective April 1, 2006.

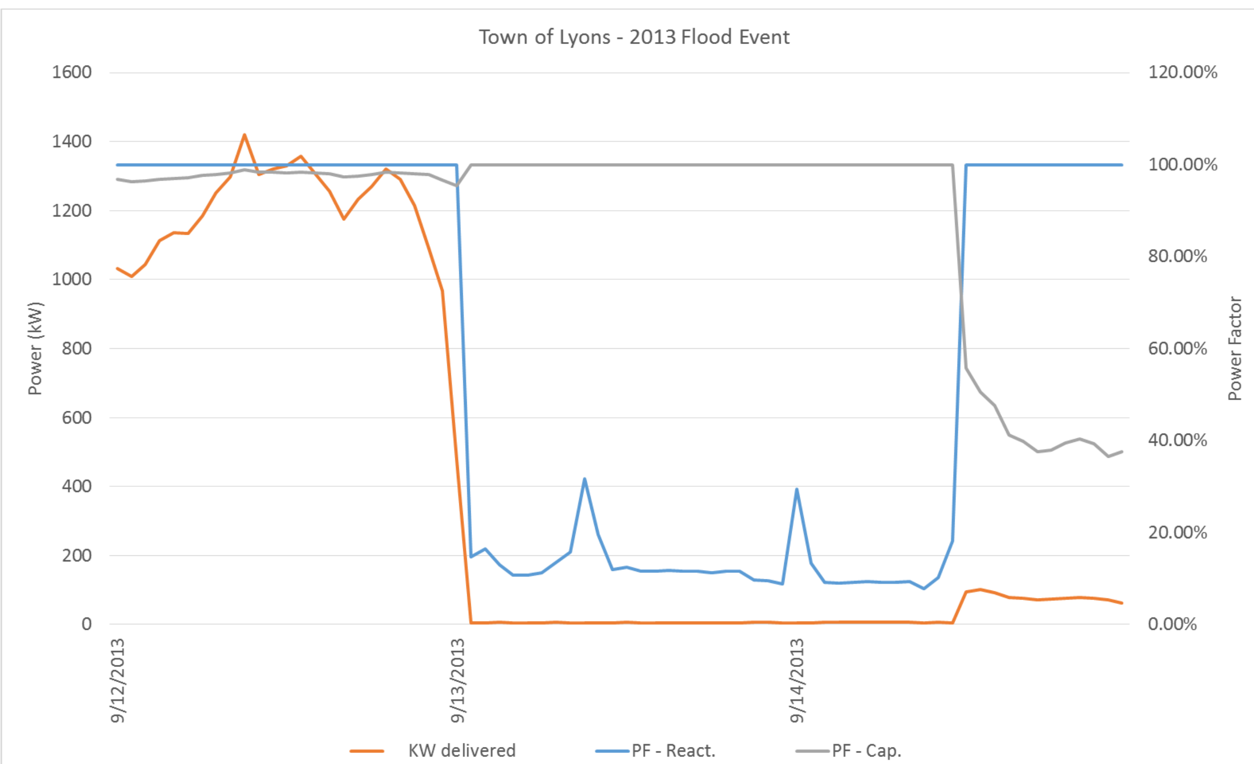
the Power Factor fall below the contractual 95 percent, MEAN would bill the Town for a higher-than-metered demand (in kW) that brings the Power Factor back to 95 percent.

2. The Flood of 2013

On September 12, 2013, a cold front collided with a low pressure zone slightly to the east of the Continental Divide; the weather system remained stationary for five days, resulting in torrential rains. The precipitation swelled the Saint Vrain Creek to record flows, which entrained large debris. The combination of flood and debris racing through the Town resulted in catastrophic losses of homes, businesses, road accesses, water and electric infrastructure. The Town lost all electricity on Friday, September 13, 2013 at 2:00 am, following a partial blackout during the preceding hour. Despite the continued downpour, a raging river gushing in the Town's main street, and extensive infrastructure damage, electric service was restored within 36 hours, at 1:00 pm on Saturday, September 14, 2013, as illustrated in Figure 10. Fortunately, the Daugherty substation, located several miles to the east, was not affected.

Incidentally, the substation's parasitic loads were still running while the substation ran unloaded, at an average of 5.23 kW of active power. Hence it is reasonable to account for 45,815 kWh of annual parasitic energy from the substation, or 0.41 percent of the Town's 2015 load. The substation's parasitic load accounts for 6 percent of the Town's average distribution losses.

Figure 10: The 2013 Flood Event Seen From Daugherty Substation

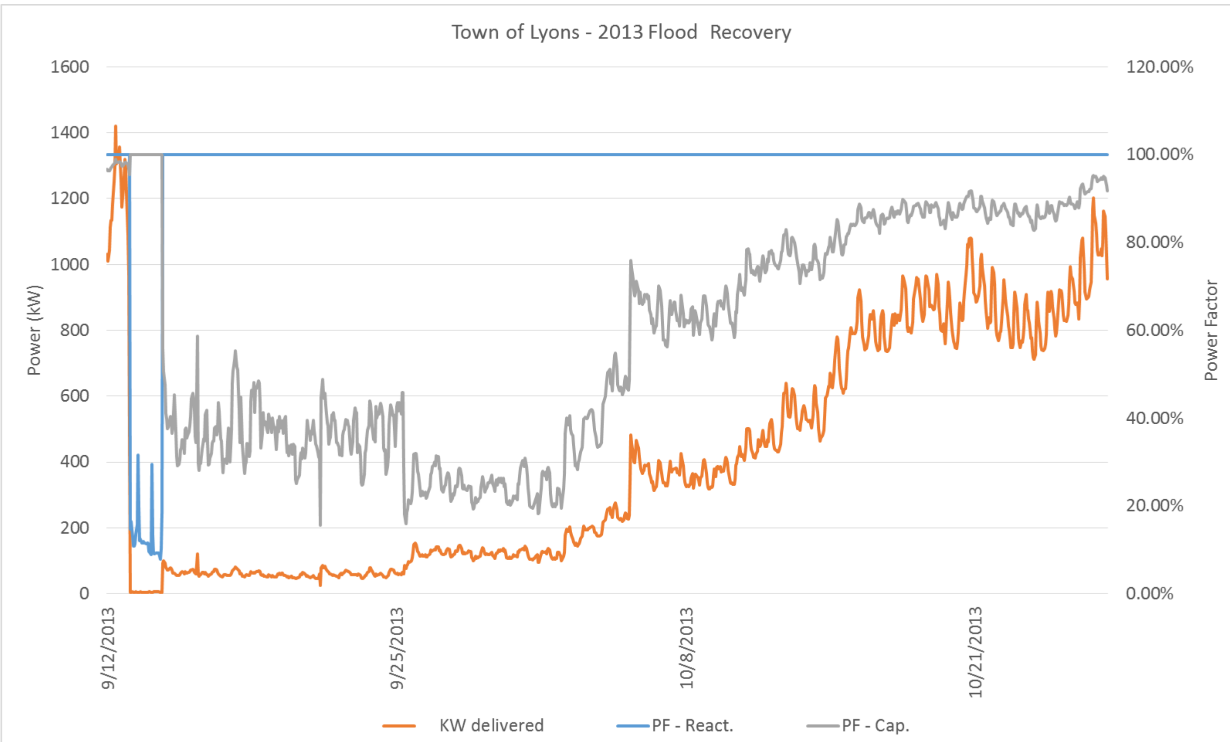


In concert with the Town's restoration efforts, electric service gradually recovered and returned to a near-normal state[9] by October 26, only 42 days after the beginning of the flood event as shown in Figure 11, albeit at lower energy and demand levels than before the flood.

The flood devastated numerous residential and commercial properties. Based on annual nominal electric consumption, the Town utility lost approximately:

- 200 residential and 60 commercial accounts in 2013
- 34 residential accounts in 2014

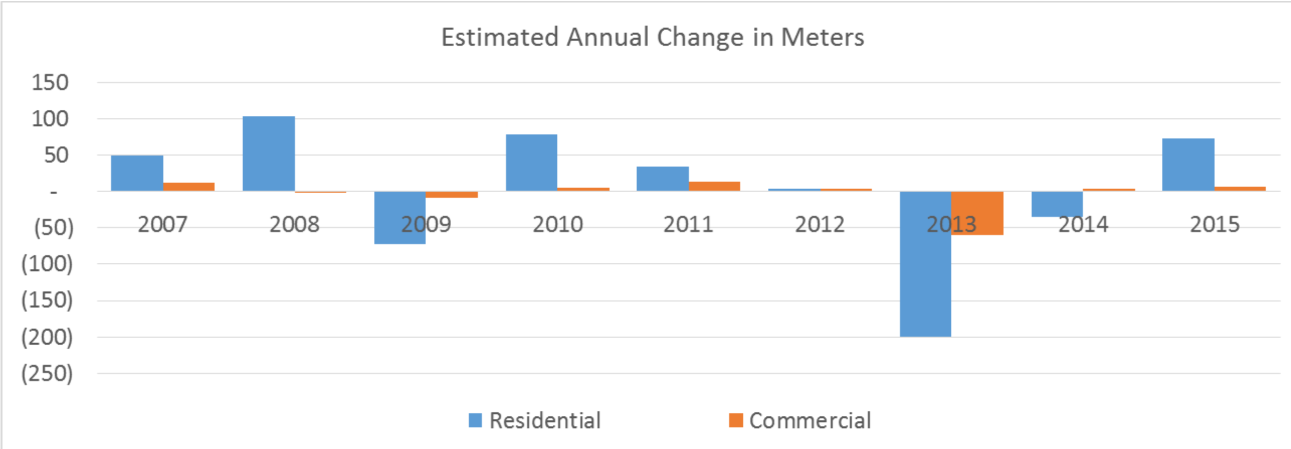
Figure 11: 2013 Flood Recovery



Worse than the economic crisis of 2008, which saw a six percent reduction in residential accounts and five percent reduction in commercial accounts, the flood of 2013 resulted in a loss of 21 percent of the residential accounts and 30 percent of the commercial accounts through 2014 (see Figure 12 below).

[9] When Power Factors are consistently above 95 percent.

Figure 12: Estimated Annual Change In Meters By Customer Class



The Town's post-flood restoration effort focused on infrastructure, utilities, and residential properties. As shown earlier, in Figure 1, the Town's total energy decreased by 11 percent in 2013 and another 2 percent in 2014 before starting a 1 percent annual recovery in 2015 and 2016.

- Residential loads, which represent approximately 60 percent of the Town's load, dropped by 10 percent in 2013 and another 3 percent in 2014 before showing a strong 3 percent annual recovery in 2015 and 2016.

- Non-Residential loads, including commercial, dropped 21 percent in 2013 and continued to drop at the rate of 3 to 4 percent in 2015 and 2016.

The incongruity between the reduction in retail energy and the loss of customer accounts stems from a higher nominal energy consumption per account during the post-flood restoration phase; it is estimated that in 2013 and 2014:

- Residential customers increased their average energy consumption by 10 percent, from 595 to 652 kWh/month/account, and

- Commercial customers increased by 17 percent, from 2,180 to 2,560 kWh/month/account.

B. Wholesale Energy and Capacity Procurement

The Town serves its retail electric load by outsourcing energy, capacity, transmission and ancillary services. It is important to outline these four billing components:

- Energy, measured in kWh or MWh (1 MWh = 1,000 kWh), serves the Town's retail electric load and distribution losses at all instants.

- Capacity, measured in kW or MW (1 MW = 1,000 kW), corresponds to the shaping of energy delivered in order to meet the Town's demand at all points in time. Capacity can be compared to a container for energy, or to a force to shape energy delivery according to the load at that instant.

- Transmission is a service provided by third parties including WAPA to transport, or "wheel", electricity from the power generation plants to the Town's substation. Transmission lines represent significant investments and are owned by such utilities as WAPA, Tri-State Generation & Transmission, and Public Service Company of Colorado.

- Ancillary services include a number of corollary activities from the transmission utilities to maintain voltage and frequency of the transmission system and the Town's distribution grid. Ancillary services include load and generation forecasting, scheduling, dispatching of regulation (up and down), spinning and non-spin reserves.

1. Inter-Connection to the Electric Grid

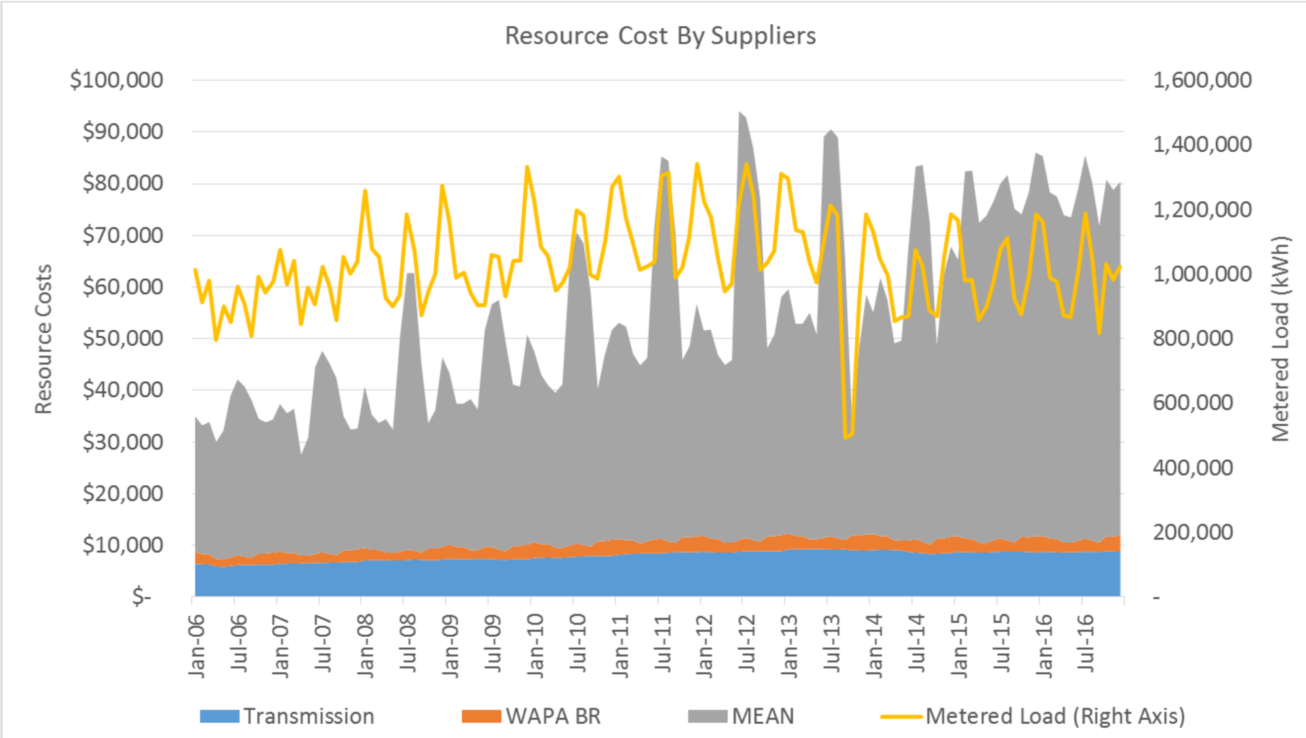
The Town receives its electrical supply from a single point of delivery at the Daugherty Substation, located at the Northwest corner of North 87th Street and Ute Highway. The substation was built between 2004 and 2006; it is interconnected directly to the WAPA 230 kV transmission grid. Meter upgrades in late 2007 provided hourly readings to support this study[10]. The single point of supply to the Town could be a concern for service reliability. However, hourly readings from the substation meter show only 12 hours of interruption from January 1, 2008 through August 31, 2016 (excluding the months of September and October 2013), which represents a reliability level of 99.98 percent. The Town's supply reliability level is higher than the "1 day in 10 years" norm (99.97 percent).

The Town procures its bulk electricity from the Western Area Power Administration's Rocky Mountain Region (WAPA-RMR) and from the Municipal Energy Agency of Nebraska (MEAN). WAPA provides a small portion of base capacity and energy, and transmission service under Network Integration Transmission Services (NITS). MEAN provides full service capacity and energy on top of WAPA's base resource, and renewable energy from wind generation. Transmission losses to the Daugherty substation over the transmission grid are estimated at 2 percent on average; hence the Town must procure two percent more bulk power and energy than is metered at the Daugherty tap.

Figure 13 shows the distribution of resource costs between WAPA (Base Energy, Base Capacity and Transmission), and MEAN (Base and Incremental Energy and Capacity, wind energy, and fixed customer charges when applicable).

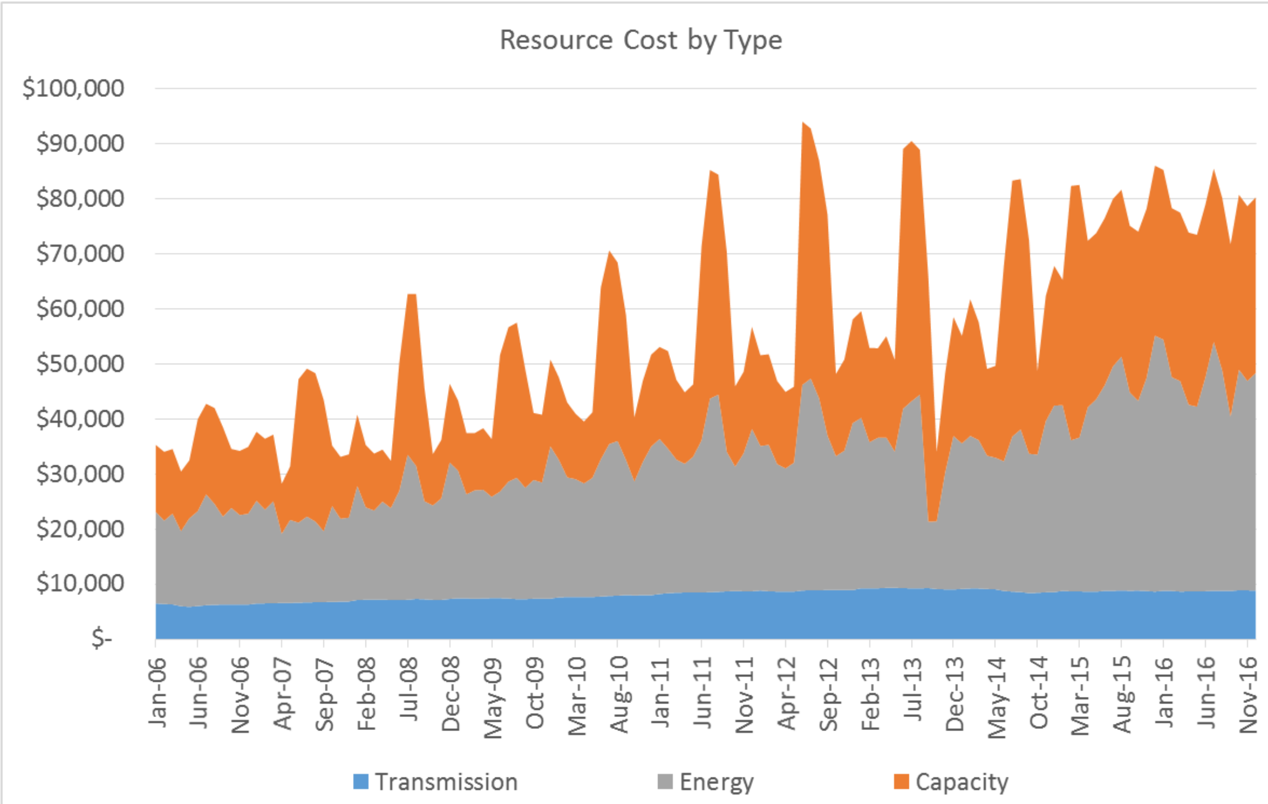
[10] No meter readings prior to December 2007 were provided for this study.

Figure 13: Town Load and Cost of Electricity by Supplier



Transmission and WAPA costs remained historically stable. Energy costs increased reasonably as well, but capacity costs, based on maximum monthly demand and seasonal rates, have impacted the Town's utility operations costs during the summer months. For example, the 1,300 kW increase in peak demand between May and June 2012 resulted in a capacity cost increase of $33,880. Starting in 2015, MEAN billed the Town a fixed monthly fee for capacity services; this new tariff provides more stable month-to-month invoicing. Figure 14 captures this change, although the stable nature of the capacity charge is not as apparent when superimposed on top of the fluctuating energy charges.

Figure 14: Wholesale Costs by Resource Type



The following sections review the Town's two wholesale suppliers, WAPA-RMR and MEAN, and detail further the price for each commodity.

2. Western Area Power Administration

The Western Area Power Administration (Western or WAPA) is a Federal Power Marketing Agency and the Control Area operator for the transmission grid to which the Town is interconnected and from which it receives its resources. WAPA is headquartered in Golden, CO, and serves a vast area in the western United States, organized into Marketing Regions; the Town is located in WAPA's Rocky Mountain Region (WAPA-RMR). In addition to providing transmission services, Western also markets hydropower generated at federal dams; the Town is served by hydro projects in the Pick-Sloan Missouri Basin Western Division, known as the Loveland Area Projects (LAP).

Figure 15: WAPA Marketing Regions (Source: WAPA.org)

The Town's energy, capacity and transmission procurement from WAPA is guided by the following Contract Agreements:

- WAPA Contract 88-LAO-434, for Post-1989 Transmission Services.
- WAPA Contract 87-LAO-123, as updated or amended, for purchase of Firm Electric Service (FES) from WAPA's Loveland Area Projects, and expiring on September 30 2024.
- The Town of Lyons' designation of the Municipal Energy Agency of Nebraska (MEAN) as its WAPA-LAP Purchasing Agent for the above two WAPA contracts. This Agreement was executed on September 25, 1989.
- WAPA Contract 14-RMR-2561, dated June 2015, for Firm Electric Services. This contract includes and amends Contract 87-LAO-123 for Firm Electric Services from Loveland Area Projects starting on October 1, 2024 and for a period of 30 years.

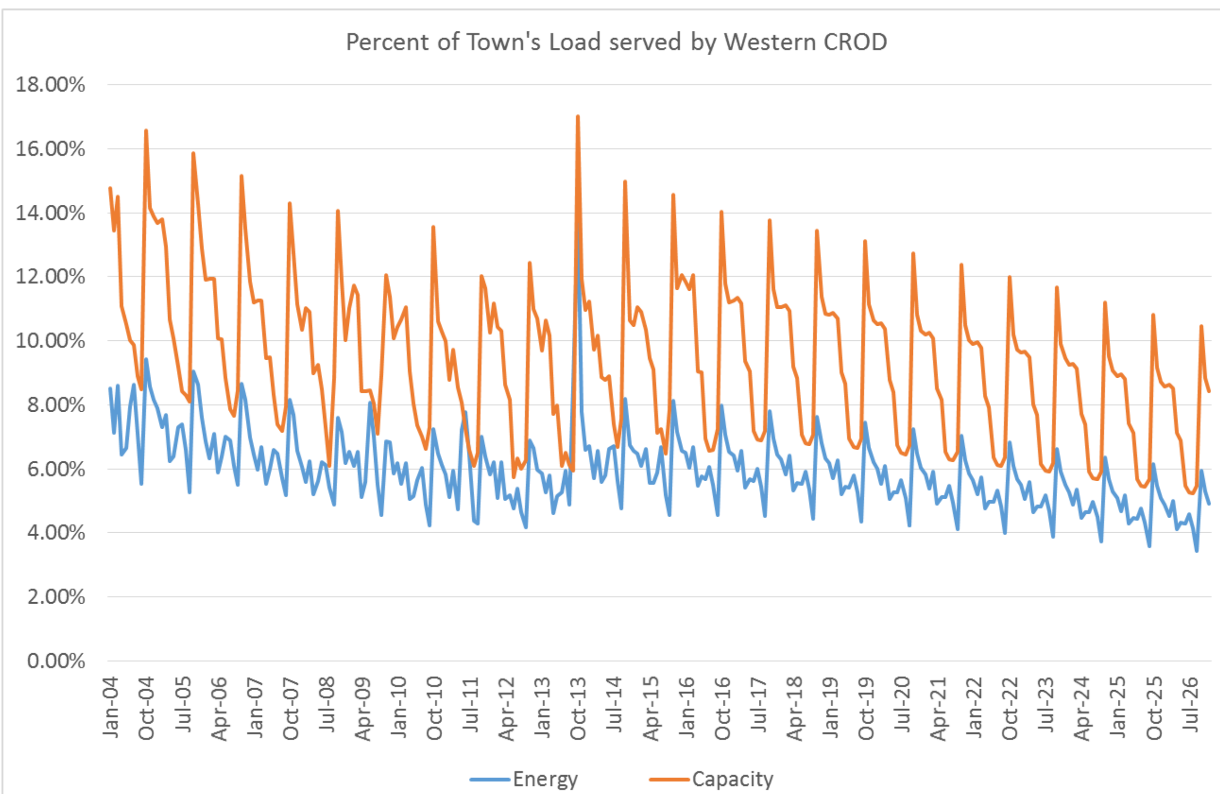
The Town receives from WAPA a fixed allocation for energy and capacity, called Contract Rate Of Delivery (CROD). The following table summarizes the energy and capacity CROD from Western as of 2015:

Table 2: Portion of Town's Load Served by WAPA in 2015

MONTH	BASE ENERGY (KWH)	***FRACTION OF TOWN'S 2015 LOAD***	BASE CAPACITY (KW)	***FRACTION OF TOWN'S 2015 DEMAND***
JANUARY	75,714	*6.48 %*	273	*11.26 %*
FEBRUARY	59,730	*6.10 %*	254	*11.13 %*
MARCH	65,199	*6.64 %*	230	*10.55 %*
APRIL	47,753	*5.57 %*	166	*9.63 %*
MAY	50,042	*5.57 %*	156	*9.28 %*
JUNE	57,565	*5.90 %*	187	*7.27 %*
JULY	71,956	*6.67 %*	201	*7.40 %*
AUGUST	57,565	*5.18 %*	177	*6.62 %*
SEPTEMBER	42,191	*4.56 %*	172	*8.01 %*
OCTOBER	71,087	*8.12 %*	260	*14.86 %*
NOVEMBER	71,087	*7.15 %*	256	*11.88 %*
DECEMBER	77,817	*6.56 %*	281	*12.31 %*

The Town's CROD allocation decreased 0.57 percent in 2010 and 0.30 percent in 2015. The CROD allocation will be further reduced by 1 percent in 2024, 2034 and 2044 for resource pools. The combination of CROD allocation reduction and projected Town load growth, averaging 3 percent per year through 2026, will result in a 2-point diminution in the percentage of the Town's load that will be served by Western in 2026.

Figure 16: Portion of Town's Electric Load Served By WAPA-LAP



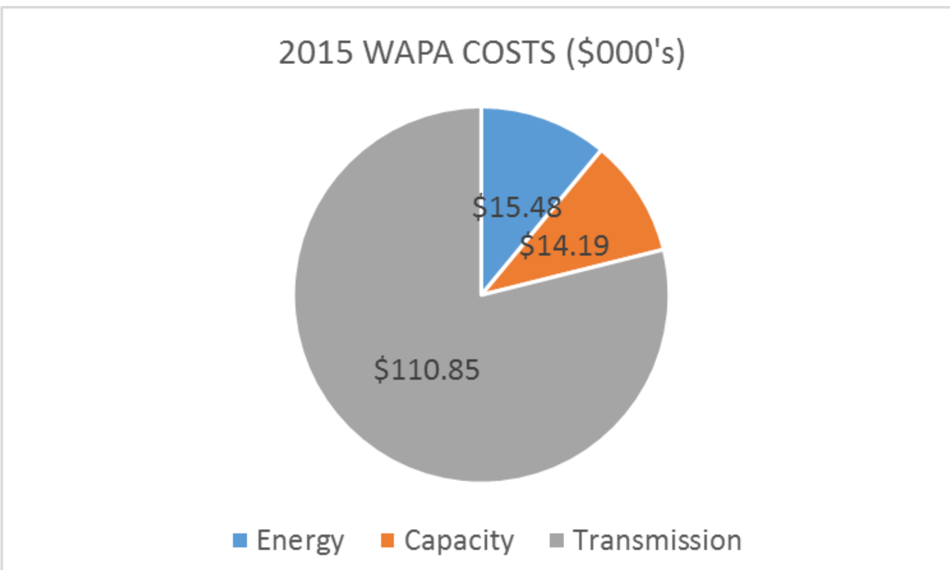
WAPA's hydropower generation energy and capacity are highest in December and January, and lowest in August and September.

WAPA's rates are set annually, under the Rate Schedule L-F10, and are projected to increase 4 percent per year[11]. The drought in the western U.S. has resulted in reduced generation from the LAP projects and the need for WAPA-RMR to purchase additional non-hydro generation to fulfill its firm delivery obligations. Despite a drought cost adder, WAPA's rates remained competitive in 2016 at 2.071 cents/kWh for energy and $5.43/kW-month for capacity.

In addition to the CROD energy and capacity services, WAPA also provides transmission and ancillary services as the Control Area Operator, which the Town receives under a Network Integration Transmission Service (NITS) arrangement. Transmission billing, passed-through by MEAN, is calculated as the 12-month average coincidental peak demand (aka "12-CP") at the time of the monthly WAPA-LAP peak hours (load ratio share) multiplied by WAPA-RMR's annual Transmission Revenue Requirement (TRR) and divided by 12. As a rule of thumb, the transmission rate has averaged $3.70 per kW-month between July 2013 and July 2016.

Figure 17 represents the annual cost distribution to the Town from WAPA for 2015.

Figure 17: 2015 WAPA-LAP Cost Breakdown to Lyons



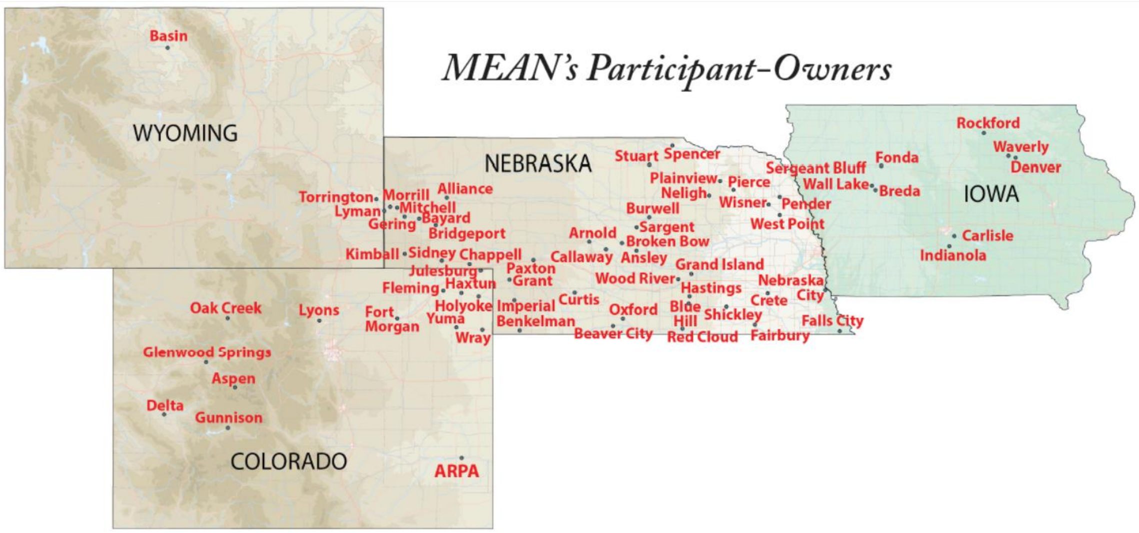
In addition, WAPA-RMR provides Network Integration Transmission Service (NITS) under the Contract 08-RMR-1811 to MEAN ("WAPA-RMR TSA") for delivery of energy and capacity to the Town. The contract expires on December 31, 2018 and will be renewed by MEAN and WAPA; there is no information available at this moment regarding any change in the terms. Typically, this type of contract is governed by the Federal Energy Regulatory Council (FERC) under the Open Access Transmission Tariff (OATT).

[11] From WAPA-RMR published 2017 LAP Rates: https://www.wapa.gov/regions/RM/rates/Pages/2017-LAP-Rates.aspx

3. Municipal Energy Agency of Nebraska

The Municipal Energy Agency of Nebraska (MEAN) serves 65 publicly owned electric utilities, including 14 in Colorado, with power and energy to supplement WAPA-RMR's firm energy and capacity deliveries. MEAN is a not-for-profit public wholesale electricity supplier, operating on a revenue-based[12] and break-even budget. The Town signed a Service Schedule M agreement with MEAN - a Total Power Requirement Purchase Agreement – in 1981.

Figure 18: MEAN Participants Footprint (Source: MEAN)



The Schedule M service agreement is based on the commitment to repay project bonds. MEAN invests in whole or partial ownership of merchant power generation plants; the portfolio of projects is financed by bonds. Importantly, Schedule M customers do not incur the bond liabilities directly; rather, they receive their proportional share of the projects' capacity and energy. Schedule M customers, such as the Town of Lyons, therefore agree to participate in the project debt service repayment in exchange for the capacity and energy needed to serve their entire load, net of WAPA-LAP's supply. In summary, the Schedule M service agreement is a form of lease on a portfolio of merchant power plants otherwise inaccessible to individual municipalities.

MEAN operates in three regions: the Western Electric Coordinating Council (WECC), the Midwest Independent System Operator (MISO/MRO) and Southwest Power Pool (SPP).

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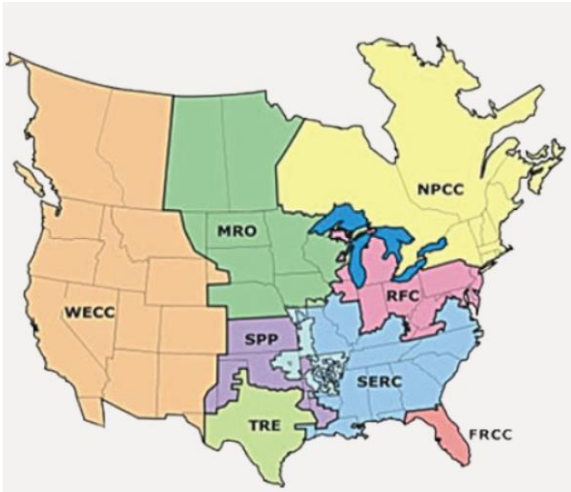
[12] MEAN operated on a cash-based budget until 2015.

Figure 19: US Electricity Market Regions



Until approximately 2009, MEAN was able to leverage its power plant investments with bilateral agreements with other market counterparties; Schedule M customers, including the Town of Lyons, benefited from MEAN's sale in the form of competitively priced energy and capacity. In 2004, Southwest Power Pool (SPP) became a Regional Transmission Organization (RTO) and extended its footprint in 2015 to include portions of the MEAN network. Under the current market paradigm, MEAN is now constrained to sell its generated energy within SPP at market clearing, rather than negotiated, prices. Furthermore, the complexities of hourly electric markets, new regulations on power plants' emissions, and new market participation rules have resulted in higher overhead costs for all utilities, including MEAN, along with reduced revenue margins. As a result, the new SPP market and regulatory environments affect the Town of Lyons in the form of increased energy and capacity costs.

a) Energy Supply

MEAN communicates the definitions, allocations, and price of energy in tariff updates each year, effective April 1. In 2006, MEAN changed the definition of the Town's metered load to include transmission losses, estimated by WAPA at 2 percent. MEAN also increased the Power Factor requirement from 90 to 95 percent. An additional tariff provision reduced the Town's net energy requirement by the amount of wind energy received.

Until 2007, MEAN supplemented WAPA's Base Energy with three products:

- MEAN Base Energy - firm deliveries of fixed monthly contractual amounts. The Base Energy was billed on a Take-Or-Pay basis, being the minimum amount of contractual energy the Town was obligated to purchase each month. This amount represented approximately 52 percent of the Town's estimated load.

- Incremental Energy - the difference between the Town's monthly load, net of WAPA's energy (Base and Support), and MEAN Base energy.

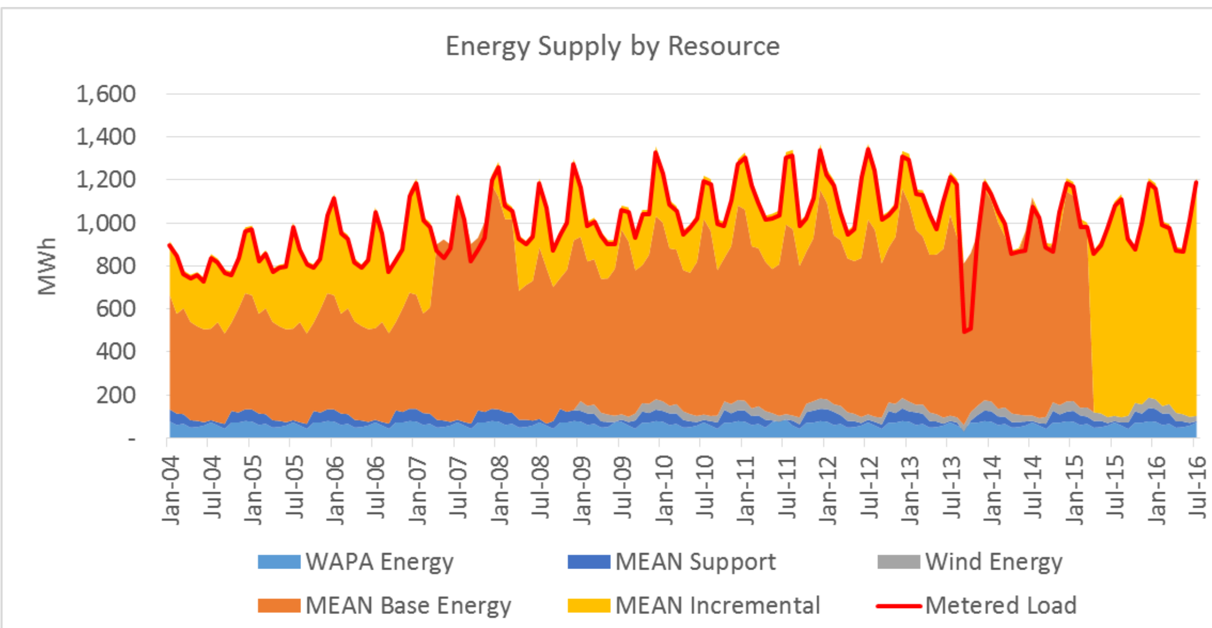
- Support energy – this complemented Western's Base Energy by prorating WAPA's Base Demand according to the Town's hourly load demand.

In 2007, MEAN increased the Town's allocation of Base Energy to meet the entirety of the forecasted net Town load. With the exception of July and December 2007, the revised amount of MEAN Base Energy resulted in a slight over-procurement for the Town but no incremental energy procurement. In 2008, MEAN reduced the Base Energy allocation back to 69 percent of the Town's load on average.

The Town subscribed to a Wind supply agreement with MEAN in 2009. Under this Power Purchase Agreement, the Town receives a firm quantity of wind energy, per a fixed monthly allocation, to offset the load otherwise served by MEAN's incremental or supplemental energy.

In 2015, MEAN simplified its tariff by removing Base and Incremental energies, minimum energy billing, summer and winter seasons, and by setting a single charge for supplemental energy. The following graph illustrates the historical supply of energy from Western and MEAN to the Town.

Figure 20: Lyons' Energy Supply Portfolio

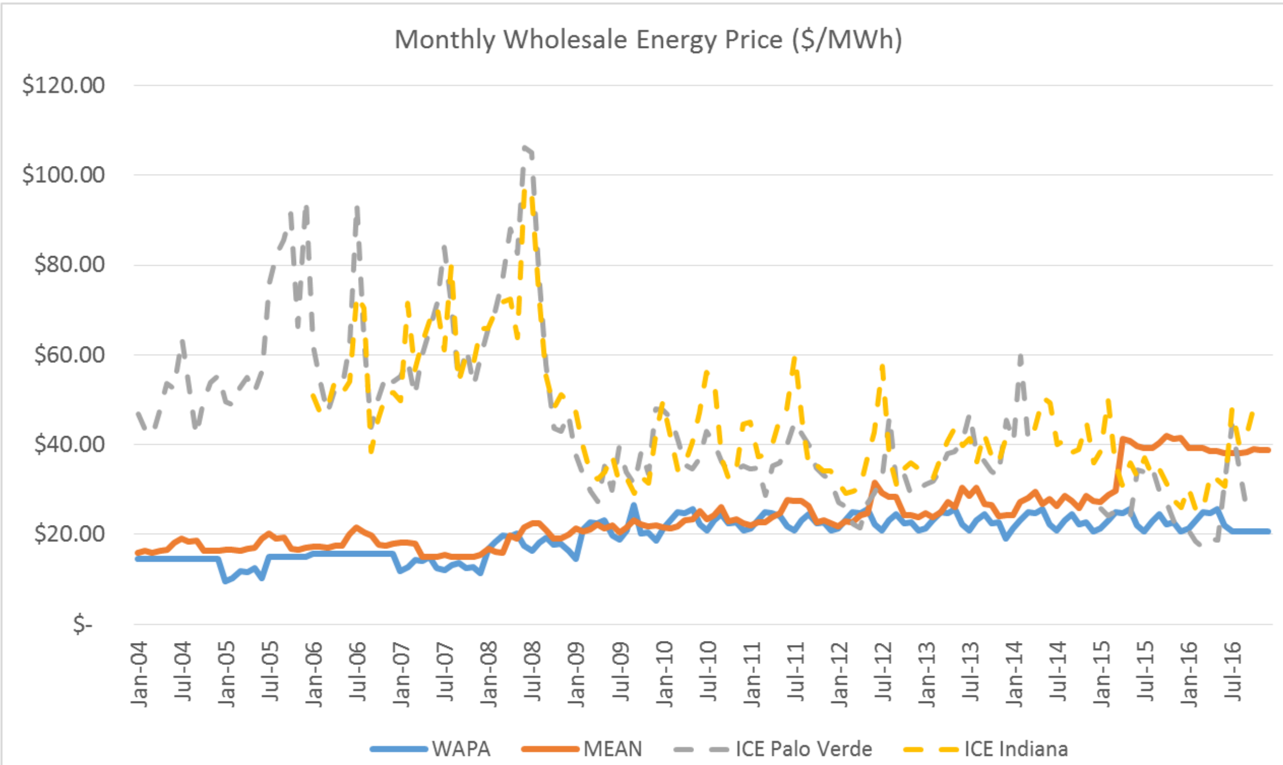


The energy rate is set annually based on forecasted Participant loads and the remaining estimated revenue required to cover all other costs of MEAN that are not included in the Fixed Cost Recovery Charge or other revenue arrangements (such as Participant wind contracts, agreements with Schedule J Participants, etc.). Generally the energy rate will be just enough to cover the costs to purchase power through Power Purchase Agreements, through market transactions and through MEAN's allocation of the costs incurred to produce power at facilities in which MEAN has an ownership share.

Figure 21 illustrates the evolution of wholesale energy cost from WAPA-RMR and MEAN between 2004 and 2016. The grey dashed line shows the historical weighted averaged Market

Clearing Price (MCP) for Colorado, and the yellow dashed line for the Midwest[13]. MEAN's energy price to the Town tracked closely with WAPA-RMR's price until 2015 and provided the Town a very competitive resource, shielded from the fluctuations of natural gas and market electricity prices in WECC and in the Midwest. The supply of energy from WAPA-RMR and MEAN has proven particularly beneficial to the Town through 2014.

Figure 21: Historical Wholesale Energy Price 2004 - 2016



In 2015, MEAN's energy price jumped 37.3 percent to nearly $40.00/MWh (4.0 cents/kWh), largely as a result of SPP's RTO expansion and recent environmental regulations on power plants[14]. As a result, MEAN energy was priced above regional historical MCPs until the summer of 2016, when the MCPs started increasing again.

The combination of energy supply from WAPA-RMR and MEAN has been a powerful hedge against market clearing and natural gas prices. Despite the 2015 price increase, MEAN energy remains attractively stable and cost-competitive.

b) Capacity Supply

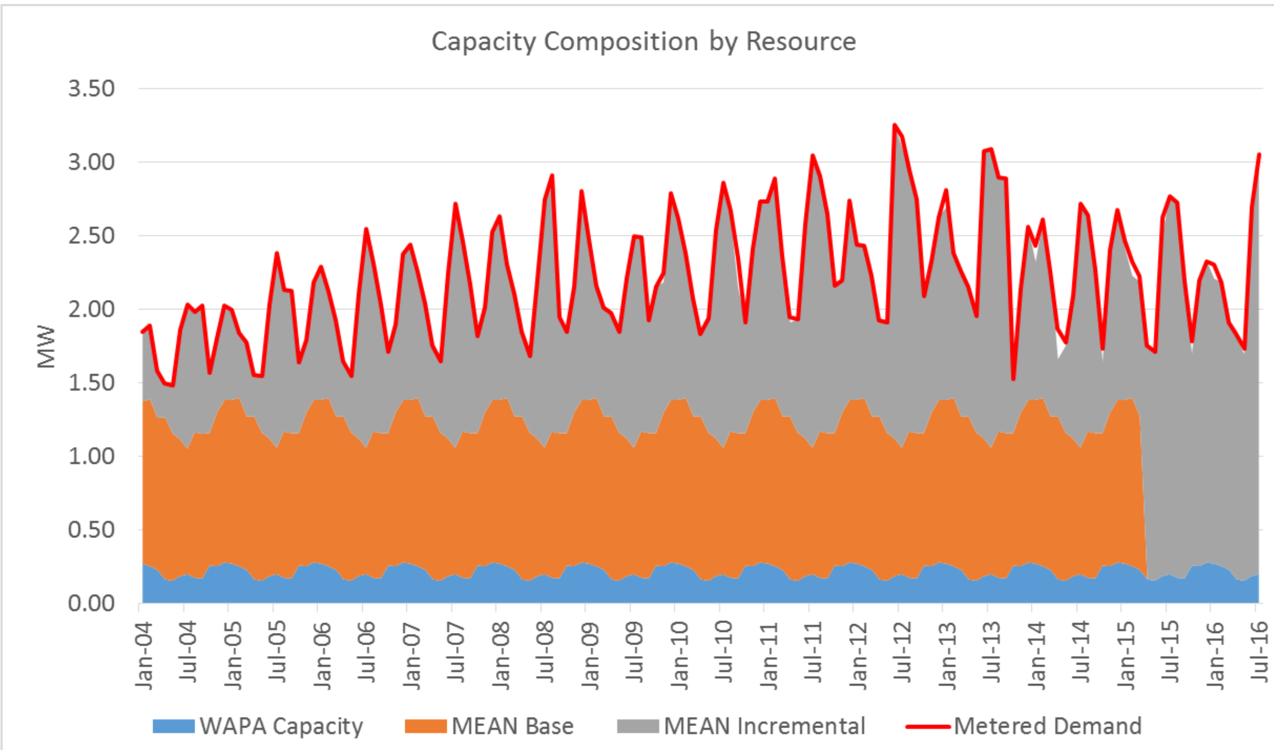
As part of the Schedule M Service Agreement, the Town receives from MEAN the capacity to supplement Western's Base Capacity and meet the Town's demand at all instances. In a similar approach to the energy supply, MEAN provides the supplemental capacity with two products:

[13] Historical Market Clearing Prices from Inter-Continental Exchange (ICE)
[14] Including Carbon Cap-And-Trade, and US Environmental Protection Agency's Clean Power Plan.

- A Base Capacity - fixed monthly and serving a fraction of the Town's demand. While the Town's total demand has increased over the years, the absolute Base Capacity allocation has not changed between 2004 and 2014; consequently the Base allocation, which averaged 57 percent of the Town's demand in 2004, only averaged 45 percent of the Town's demand in 2014.

- An incremental capacity - to fulfill the Town's remaining demand net of Western's and MEAN's Base Capacity allocations.

Figure 22: Town's Historical Capacity Supply



MEAN removed the Base Capacity from its Schedule M tariff in 2015; the Town's demand is now met with incremental capacity, but at a fixed monthly charge. The new Fixed Cost Recovery charge consists of fixed costs related primarily to MEAN's ownership of generation, the operation of MEAN and the following costs:

- Budgeted administrative and general expenses, net of asset rent from other NMPP Energy companies and annual meeting sponsorships & registrations.

- Debt service on contracted capacity for MEAN's share of generating assets:
  - Whelan Energy Center Unit 2 (WEC2) through Public Power Generation Agency (PPGA), including WEC2 Assignment net of budgeted debt service offsets such as interest income and subsidies on Build America Bonds.

- Hastings Whelan Energy Center Unit 1 (WEC1) Assignment, Walter Scott Energy Center 4 (WSEC4) Waverly Assignment, Louisa Generating Station (LGS) Waverly Assignment, Nebraska Public Power District (NPPD) Cooper Nuclear Station (CNS), and NPPD Gerald Gentleman Station (GGS).

- Principal and interest payments on MEAN's outstanding debt, net of Rate Stabilization funds.

- Annual budgeted capital costs net of Rate Stabilization – Capital funds.

- Utility basis budget adder to keep targeted revenue requirement and financial ratios within acceptable ranges.

4. Renewable Energy Standard and Procurement

In November 2004, Colorado passed Amendment 37 "Colorado Renewable Energy Requirement Initiative" to establish a regulatory requirement for electric utilities to generate or cause to be generated electricity from eligible energy resources in proportion with their retail electricity sales. The requirement for State Renewable Energy Standard (RES) varies by utility type and size; municipal utilities serving more than 40,000 customers and electric cooperatives serving fewer than 100,000 meters are required to meet a 10 percent renewable generation standard by 2020. Larger utilities have more ambitious RES requirements.

As a municipal utility serving less than 1,100 meters, the Town of Lyons is not subject to the state RES. Nevertheless, the Town has been proactive in the procurement and development of renewable energy:

- Western's Base Energy, which derives largely from hydropower generation, supplied an average of 6.2 percent of the Town's load in 2015.

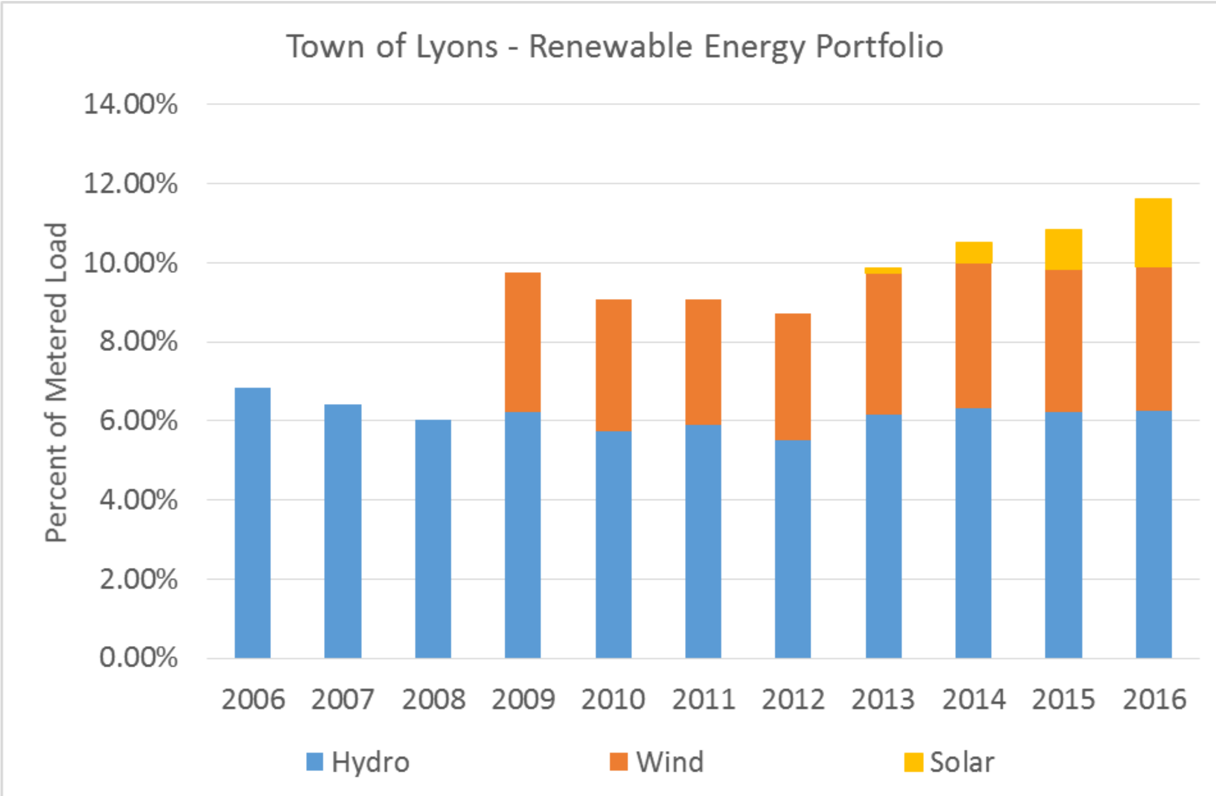
- MEAN's wind contract averaged 3.6 percent of the Town's load in 2015.

- Starting in 2013, the development of distributed solar generation has brought the Town's total renewable energy percentage above ten percent.

Figure 23 shows the approximate percentage of renewable energy for the Town's load. It assumes that all WAPA-LAP generation is renewable (hydro); total solar energy production is estimated from installed capacity.

At this time, both WAPA-RMR and MEAN retain the Renewable Energy Credits (RECs) from their respective resources. To implement an RES program, the Town could claim its share of the RECs from the generation owners (Western, MEAN, PV solar owners), then transfer and retire them through the Western Renewable Energy Generation Information System (WREGIS). Conversely, the Town could turn its solar RECs over to MEAN to help reduce the cost of regulatory compliance.

Figure 23: Approximate Percentage of Renewable Energy in Town's Load



C. Utility Revenues

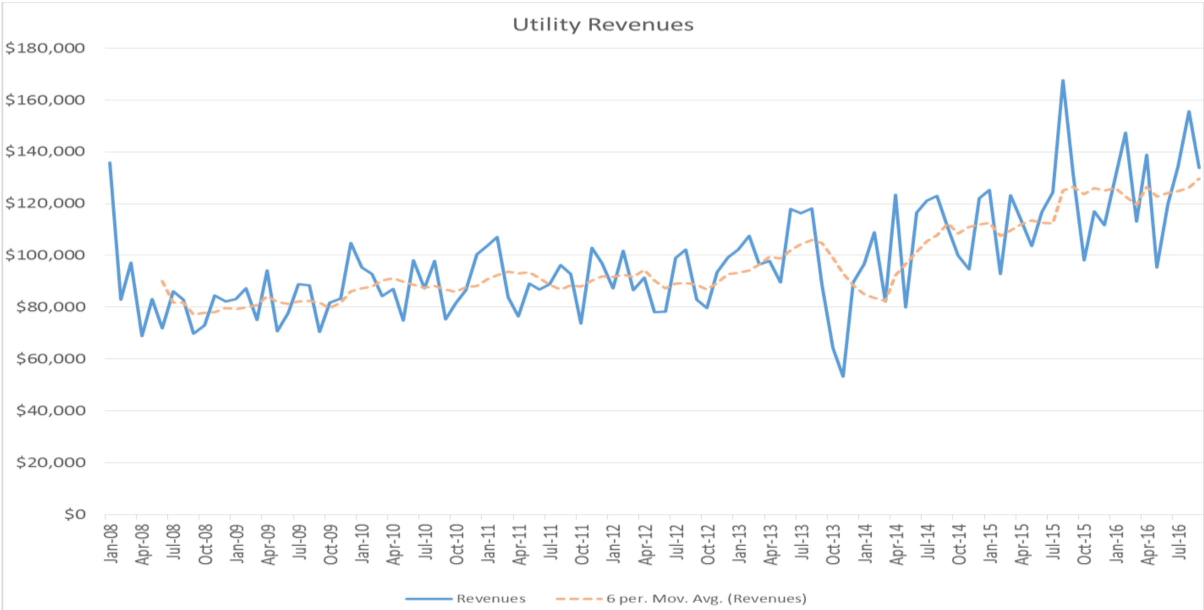
Reported Revenues were reviewed for the years 2008 – 2016.

With the exception of $60,434 of "Other" revenue reported in 2012, nearly 100% of total revenues were derived from the sale of power. The discussion below, therefore, presumes that period-to-period changes in revenues are due principally to changes in power charges/usage.

Figure 24 below demonstrates how the revenues reflect usage patterns, with peaks in summer and winter and lows in spring and fall.

The Town's monthly and yearly revenues exhibit a steady upward trend, as evidenced by the slowly rising six-month moving average curve below (orange line).

Figure 24: Total Utility Revenues by Month



Note: The amount reported for January 2008 Revenue in the General Ledger ($135,994) appears to be unusually large.

Somewhat apparent, but not obvious, is the fact that the year-over-year percentage increases in the Town's annual utility revenues have been higher in recent years. This cannot be explained entirely by load increases, which were either negative or modestly positive during the same period.

Table 3: Comparison of Growth in Revenues and Load

	2008	2009	2010	2011	2012	2013	2014	2015	2016 (fcst)
Customer Charges (000s)	$953	$987	$1,021	$1,083	$1,045	$1,099	$1,233	$1,379	$1,540
YOY $		$34	$34	$61	($38)	$54	$134	$146	$161
Charges YOY %		3.6%	3.5%	6.1%	(3.5%)	5.2%	12.2%	11.8%	10.9%
Load YOY %		(1.1%)	5.9%	5.2%	(0.9%)	(10.5%)	(2.5%)	1.4%	0.8%

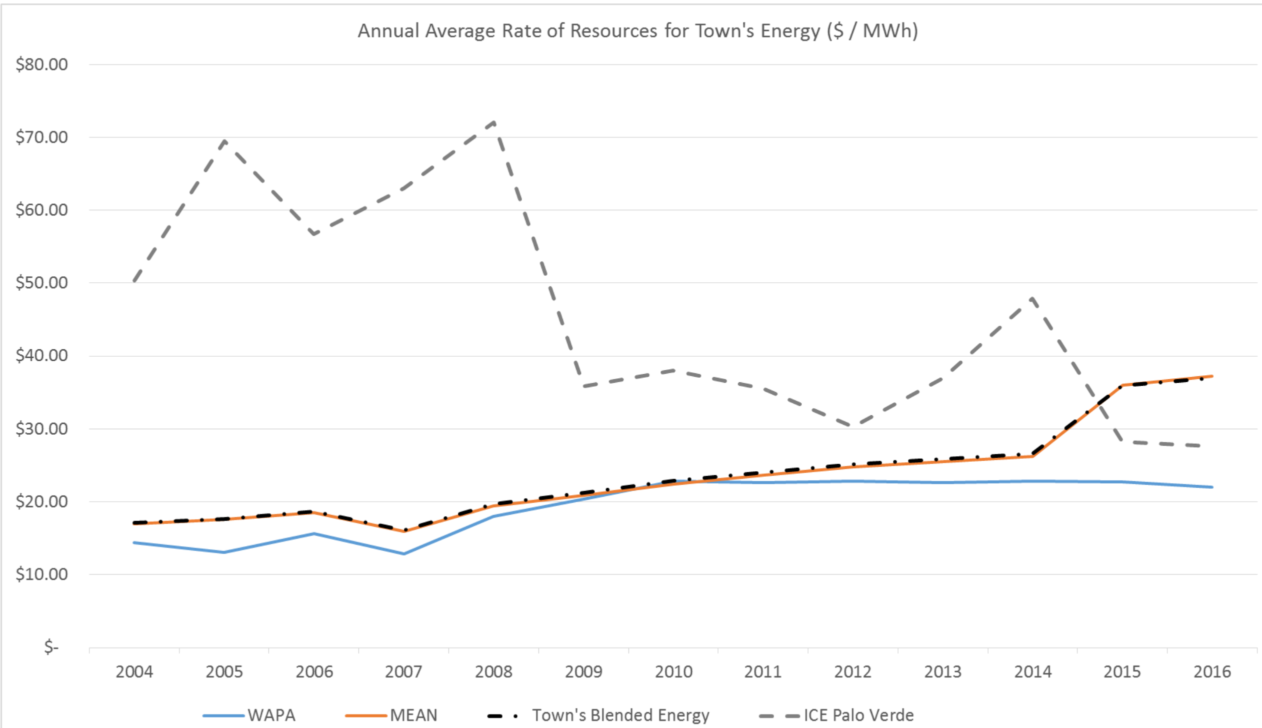
As discussed elsewhere in this report, given that revenue growth is generally higher than load growth, the increase in historical revenues appears to be driven more by higher rates than by higher customer demand, particularly in more recent years.

D. Utility Operating Expenses

1. Electric resource procurement

The price of wholesale energy to serve the Town's load was $24.02 per MWh of load (2.4 cents/kWh) in 2011 and $37.00/MWh (3.7 cents/kWh) in 2016. The Town's 12-year history of blended wholesale energy price compares favorably to Market Clearing Prices in Colorado[15]; from 2004 to 2016, WAPA has shown an average price increase of 4.4 percent annually. MEAN's prices, which remained close to WAPA's until 2014, increased by 37 percent in 2015. Accounting for the transmission losses, the Town's net energy rate[16] tracks MEAN's rate closely.

Figure 25: Wholesale Energy Procurement Price and Comparative MCP



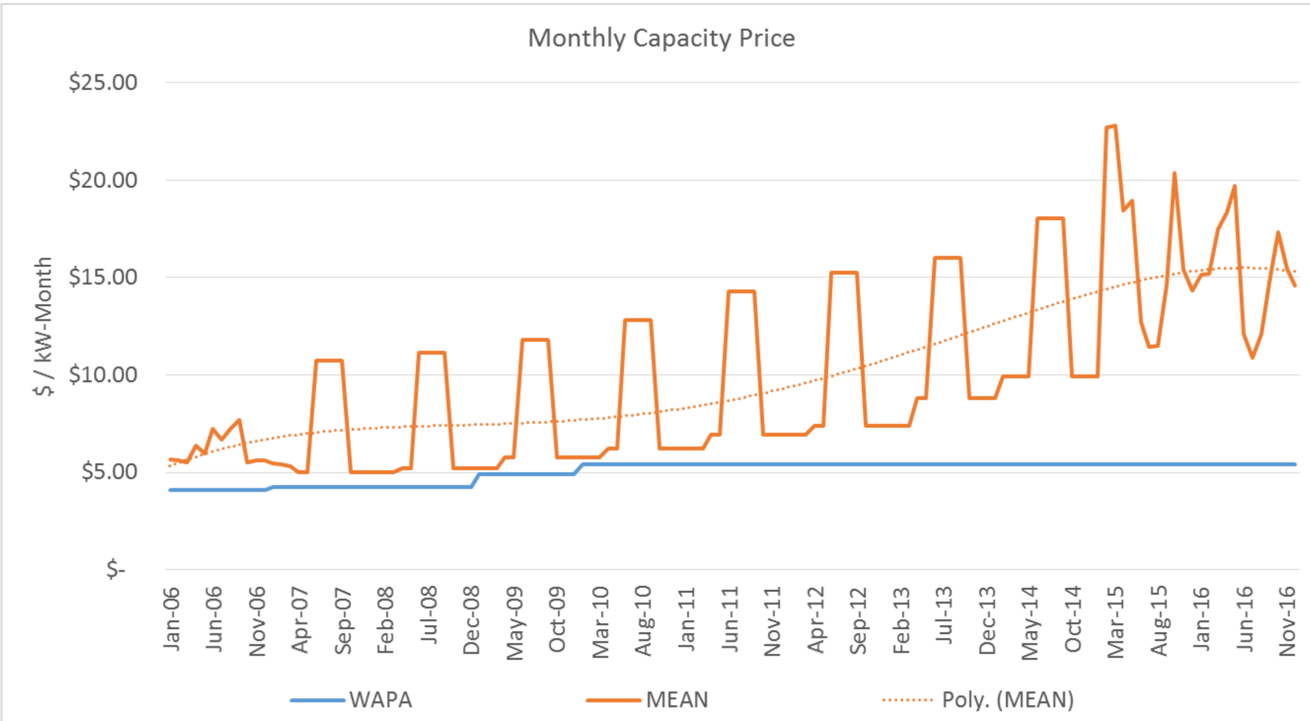
The Town's capacity is provided entirely by WAPA and MEAN. WAPA's capacity price is comprised of the contract Base Price and a Drought Adder. Base capacity price has increased at an annual average of 3.0 percent per year. WAPA's drought adder, which increased to $2.64 per kW-Month in 2010, was reduced to $1.51 for 2015 and 2016[17]. The combination of increasing Base price and decreasing Drought adder results in a 3.6 percent annual average increase between 2006 and 2016, but a stable post-2010 capacity price.

MEAN's capacity price follows a different set of tariffs. Until 2015, MEAN charged a seasonal price, with low winter and high summer rates, for a Base and an Incremental capacity product; notably, MEAN adjusted its tariff in 2007 and raised the incremental capacity price to match the

[15] Reference: Inter-Continental Exchange (ICE)
[16] Defined as the total energy costs divided by the Town's load metered at Daugherty.
[17] Reference: WAPA-RMR Rate Schedule L-F10 – www.wapa.gov

Base price. In 2015, MEAN converted its variable capacity pricing to a fixed monthly fee called "Fixed Cost Recovery". Figure 26 highlights the monthly capacity pricing from WAPA and MEAN; 2015 and 2016 MEAN capacity pricing is the Fixed Cost Recovery charge divided by the capacity delivered to the Town.

Figure 26: Historical Monthly Capacity Prices 2006 to 2016



MEAN's capacity price includes:

- The Town's share of MEAN's 2013 and 2016 bond series Debt Service Repayment.
- Capacity supply, including the procurement of capacity in East Colorado to serve the Town's demand, in part from other MEAN members under the Schedule M tariff's "CAPACITY COMMITMENT COMPENSATION".
- The Town's share of MEAN's Overhead costs, including budgeted administrative and general expenses, net of asset rent from other NMPP Energy companies and annual meeting sponsorships & registrations.

Looking at MEAN's capacity cost on an annual basis, the cost drivers are essentially MEAN's 2013 and 2016 series bonds repayment, its overhead costs and the commodity cost of capacity. If we assume MEAN's capacity price to follow WAPA, apply the Principal and Interest repayment for the 2013 and 2016 series bonds in proportion to the Town's share of MEAN revenues[18], it appears that the overhead portion increased significantly between 2012 and 2015, but stabilized

[18] The Town of Lyons represents approximately 0.5 percent of MEAN's electric sale, energy sale and non-coincidental annual demand. Percentages vary annually but remain below 0.6 percent.

in 2016 with the Fixed Cost Recovery charge in lieu of variable capacity pricing. This overhead increase is likely driven by environmental regulations, SPP's expansion into MEAN service territory, and the implied retooling of the Joint Action Agency operations required to participate in the new RTO market. It also includes implicit services provided to the Town such as load forecasting, load and resource scheduling, wholesale settlements validation and payments.

Figure 27: Estimated MEAN Capacity Cost Components

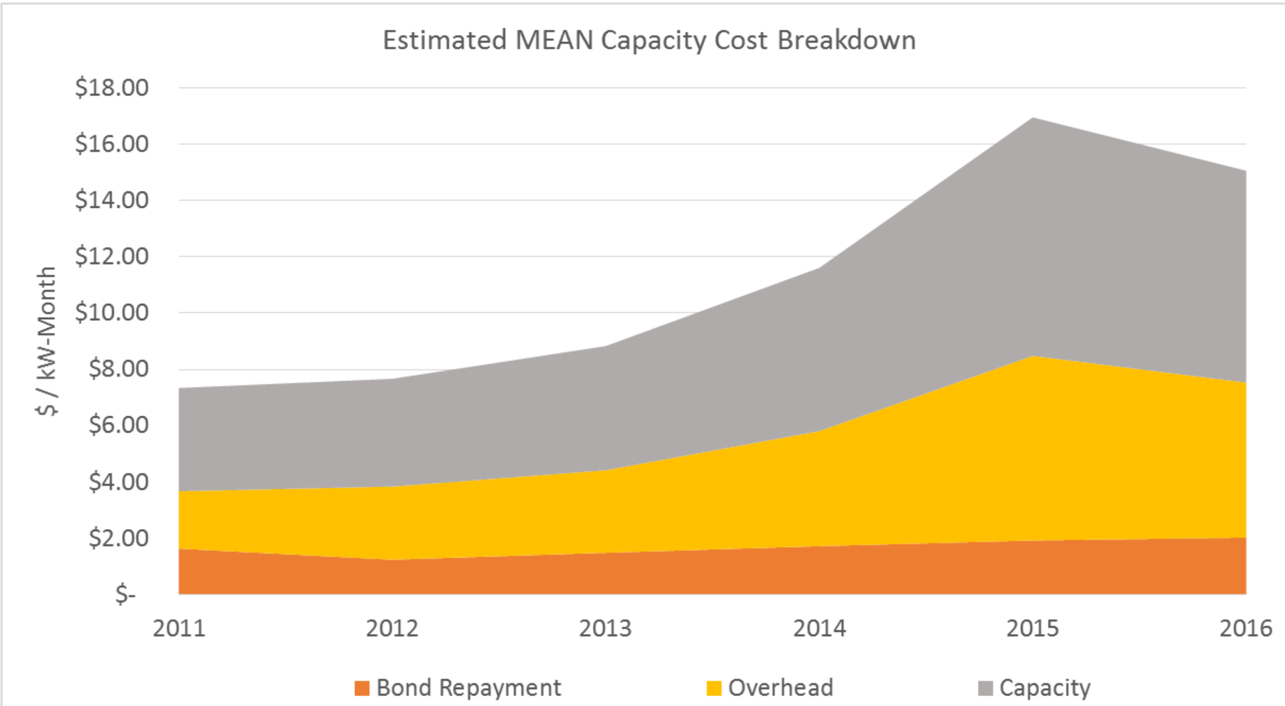
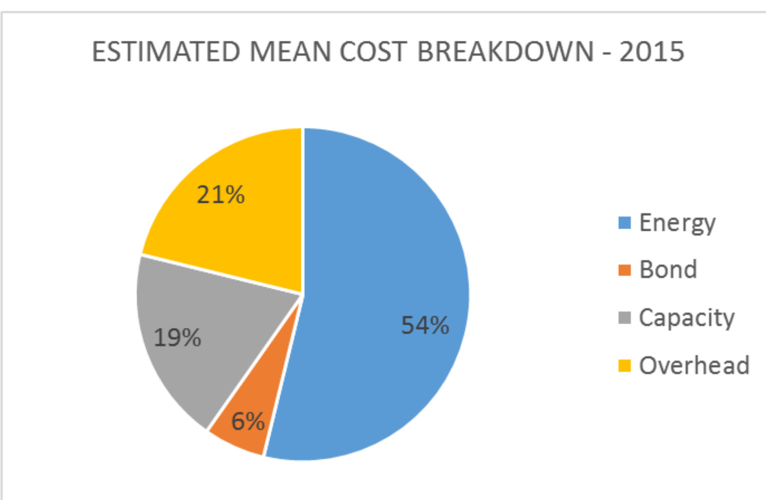


Figure 28 illustrates the 2015 estimated breakdown for all of MEAN's costs to the Town.

Figure 28: Estimated Breakdown of MEAN Costs in 2015



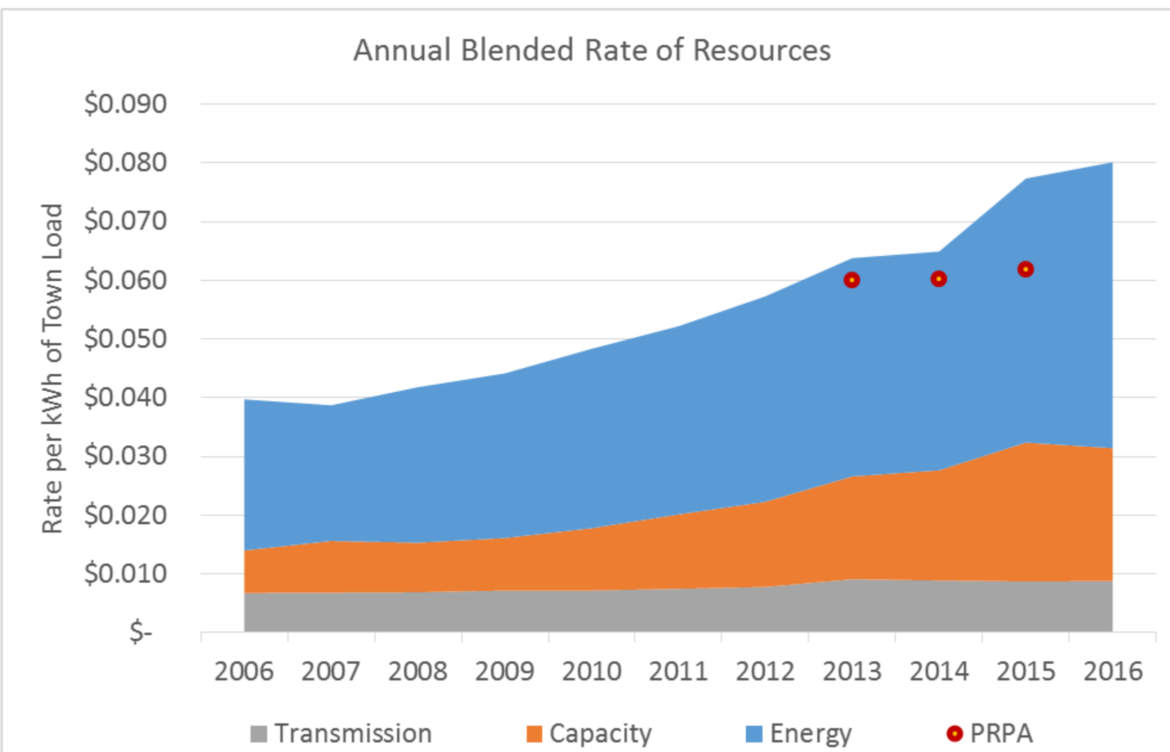
In its 2015 tariff, MEAN has substituted a Fixed Cost Recovery charge in place of capacity rates. As a result, the capacity cost applied to the Town's load now shows a reversed pricing pattern, with a comparatively low rate during the Town's peak demand seasons (winter and summer). The fixed monthly charge appeals by simplifying the allocation of demand charge to retail customers with energy meters.

The Fixed Cost Recovery fee is adjusted annually according to the Town's prior year peak demands. This form of fixed capacity pricing does not reward instantly any effort to reduce the Town's demand; instead it will average the cost of capacity supplied to the Town over time. However, there is still an incentive to reduce peak demand or increase Load Factor, such that capacity cost has a reduced impact on the Town's blended wholesale price.

Figure 29 shows the annual energy, capacity and transmission costs applied to the Town's load. While WAPA and transmission charges remained around $10/MWh in the aggregate, MEAN rates have doubled since 2007. As a result, the Town's wholesale resource price has increased on average by 10.8 percent per year to a rate of $80.13/MWh in 2016.

The drawback of blending the rate against the Town's energy is that it does not highlight the capacity cost impact. It provides, however, a price comparison for the development of Distributed Generation that has capacity value, such as local hydropower or natural gas generation. Such local and dispatchable resources can offset transmission and capacity procurement costs. However, the blended rate is not suitable to compare against alternative wholesale generation, or local Distributed Generation that does not provide capacity, including intermittent generation such as PV solar.

Figure 29: Historical Blended Load Energy Cost - $ per MWh of Load



The Town's blended rate is a function of the Town's metered load, energy and capacity costs procured from WAPA and MEAN. The period between 2008 and 2012 showed an average annual rate increase of 8.16 percent. Load reduction and changes in the MEAN tariff resulted in in a 10.76 percent annual average rate increase between 2013 and 2015. Finally, 2016 rates are 3.59 percent over 2015. Figure 29 above also provides 2013 – 2015 price points from Platte River Power Authority[19] for comparison.

MEAN's Long Term Total Requirement (Schedule M) Participants have agreed to purchase all of their electric requirements from MEAN, net of any firm power and capacity from WAPA, at rates sufficient to enable MEAN to pay all the costs of its Power Supply System, including the debt service on the 2013[20] and 2016 Series Bonds. Note, however, that Aspen, CO, has set a precedent by the addition of a locally owned hydropower resource into the MEAN Schedule M agreement. Likewise the Town could add local resources in one of two ways:

- Either enter into a new project agreement with MEAN, letting MEAN finance and develop the project, and purchase the resource energy and capacity based on MEAN's rates with the adder of the project financing.

- Finance and develop the project internally, letting MEAN purchase the energy at its FERC-filed PURPA[21] rate for avoided energy generation, and buy back the energy from MEAN.

Either scenario has the potential to avoid transmission costs and, given due coordination with MEAN, possibly offset some capacity charges.

2. Capital Expenditures and Debt Service

a) *Capital Expenditures*

The Asset Depreciation Report, dated December 31, 2015, served as the primary source for the analysis of Capital Expenditures. This report lists 45 capital assets, with a total cost of $3.3 million and a net book value of $2.3 million. In addition, the Town of Lyons Electric Fund holds property and property rights[22], with a value of $49,215. This is a non-depreciating asset.

A significant portion of the Electric Fund's Capital Assets are in the substation that was built between 2003 and 2006. Given the initial cost of $2.2 million ($2,057,729 + $188,347) and a useful life, for accounting purposes, of 40 years, the annual depreciation on this asset is roughly $56,000.

For the years 2008 through 2014, periods for which Financial Statements are available, the Electric Fund has been investing at a rate that is roughly in line with the annual depreciation

[19] Derived from available PRPA annual Financial Statements.
[20] From MEAN's 2013 Official Statement of Power Supply System Revenue and Bonds.
[21] Public Utility Regulatory Public Act of 1978.
[22] Referred as Land and Water Rights

charges, net of depreciation on the substation. See Table 4 below. From a pure financial perspective, this indicates that investments are being made at a rate that is adequate for maintaining the long-term viability of the capital plant *exclusive of the substation*.

The Electric Fund, however, is also spending approximately $115,000 to $118,000 per year to pay down the two bonds sold in 2003 and 2006 (see "Long Term Debt" section below). These bonds were issued to help pay for the substation construction. They will be paid off in 2023 and 2026, respectively, at which time the substation will be approximately half-way into its expected 40-year life. At this point some of these funds should be freed up for re-investment into the substation, or a capital improvement fund, or some other mechanism for continuing the long-term sustainability of substation infrastructure.

Table 4: Investments in Capital Plant & Equipment

Changes in Capital Plant	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**Avg.**
Capital Additions (000s)*	$3	$46	$0	$41	$128	$30	$29	**$40**
Depreciation (000s)**	$91	$88	$87	$92	$97	$97	$97	$93
- Substation***	$56	$56	$56	$56	$56	$56	$56	$56
- Distr'n (derived)	$34	$32	$31	$36	$41	$41	$41	**$37**
Cap Add'ns: Annual F/S⁺	$3	$46	$0	$57	$161	$5	$3	$39

* Capital Additions derived from Asset Depreciation Report, dated December 31, 2015
** Depreciation derived by subtracting annual Amortization of Bond Issue Costs ($2,832) from reported Depreciation and Amortization charges in Audited Financial Statements.
*** Substation Investments of $2,057,729 and $188,347 made in 2003 through 2007
⁺ Note that Audited Financial Statements report capital additions in 2011 through 2014 that do not match those derived from the Asset Depreciation Report. This analysis is based on values reported in or derived from the Asset Depreciation Report.

b) *Long-Term Debt*

Per the 2014 Audited Financial Statements,

> "Revenue bonds in the amount of $1,480,000 were issued October 15, 2003 for the purpose of constructing an electrical substation. The average coupon rate is 4.76% over twenty years with final payment on December 1, 2023… The balance on this bond at fiscal year-end (12/31/2014) is $820,000.
> In 2007, a revenue note was issued in the amount of $412,000 in support of the same project. The rate on this note is 5.4% with a twenty-year term. The balance as of December 31, 201(4) is $296,317."

As noted above, the recorded cost of the substation that backs this debt is roughly $2.2 million, which is more than the $1,892,000 debt issued. The Financial Model treats the balance as an internally-funded capital investment in 2006.

The repayment schedules for these two debt instruments take different forms.

- The $1.48 million Revenue bond is being repaid according to a fixed semi-annual payment schedule, with interest payments due June and December and a principal payment due in December.
- The $412,000 revenue note is being repaid in twenty equal payments each August. The repayment schedule is based on a normal loan amortization schedule wherein the amounts allocated to interest decline and the amounts allocated to principal increase in each payment period.

According to the terms of the two loans, the Revenue Bond will be fully repaid in December 2023 and the Revenue Note will be repaid in 2026.

A widely used metric used to determine an enterprise's financial health is Debt Service Coverage Ratio, or DSCR. Per Investopedia.com, the DSCR is

> "a measure of the cash flow available to pay current debt obligations. The ratio states net operating income as a multiple of debt obligations since [a given] year, including interest, principal,… and lease payments"

A DSCR of 1.0 or more indicates that the enterprise has enough cash flow to meet its debt obligations. Below 1.0 indicates a shortage. Most utilities strive to maintain a DSCR of 1.25 or better, so as to maintain their bond rating and satisfy other creditors that the utility is managing its finances appropriately.

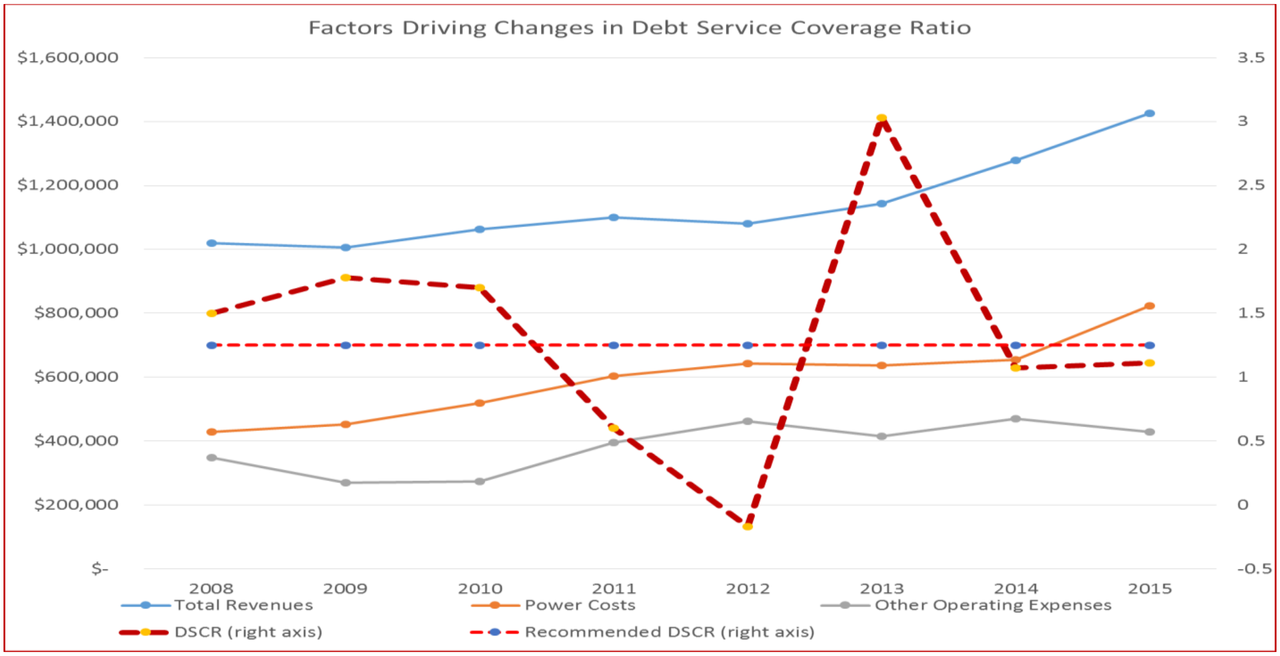
As shown in Table 5, since 2008, the first year for which financial statements are provided, the Town of Lyons Electric Fund's DSCR has been mostly above 1.25, with a few excursions below 1.0 in 2011 and 2012.

Table 5: Historical Debt Service Coverage Ratio

	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
DSCR	1.50	1.78	1.70	0.60	-0.17	3.03	1.07	1.11

Figure 30 shows that the downturn in DSCR in 2011 and 2012, and to a lesser degree in 2014, can be attributed primarily to increased operating expenses in these periods. More specifically, in 2011 and 2012, Total Revenues collected from sales of power were mostly unchanged, increasing by only $37,000 in 2011 and declining by $18,000 in 2012. In these same periods, Power Costs increased by $85,000 and $39,000, respectively, and Other Operating Expenses increased by $122,000 and $66,000, respectively. Note that debt service payments did not change significantly during these same years. As these represent the denominator of the Debt Service Coverage Ratio, it is the numerator, or cash flows, which explain changes in DSCR over the time period evaluated.

Figure 30: Principal Factors Driving Changes in Debt Service Coverage Ratio by Factor



3. Operations Expenses

Reported Expenses were reviewed for the years 2008 – 2016.

Expenses were categorized into three principal categories:

- Cost of Power
    - Reviewed in detail earlier in this report.
- Administrative Expenses
    - Full-time/Part-time Salaries, Office operations, Attorney fees, etc.
    - These include the expenses reported as “EF's Share Alloc Exp's from GF”.
- Maintenance (Distribution) Expenses
    - Maintenance Salaries, Outside Professional Services, Vehicle maintenance, Tree Trimming, Maintenance & Supplies, etc.
    - Does not include Electric Power costs

Administrative Expenses

For the analysis of administrative expenses, individual administrative accounts were grouped as follows:

Salaries & Benefits:

- 02-50-4000 – Full Time Salaries (Admin)
- 02-50-4001 – Part Time Salaries

- 02-50-4024 – Payroll Taxes – ER
- 02-50-4025 – Employee Ins – ER
- 02-50-4026 – Retirement Contribution - ER

Office Operations & Equipment

- 02-44-4008 – Office Operations
- 02-44-4010 – Postage
- 02-44-4011 – Eqpt Maintenance
- 02-44-4041 – PC, Software, Printers
- 02-44-4055 – PC Technician Fees
- 02-44-4057 – Telephone Exp
- 02-44-5009 – Copier Lease Expense
- 02-50-4008 – Office Operations
- 02-50-4010 – Postage
- 02-50-4011 – Equipment & Small Tools
- 02-50-4041 – PC, Software, Printers
- 02-50-4055 – PC Technician Fees

Professional Services

- 02-44-4032 – Attorneys Fees
- 02-44-4033 – Engineering Fees
- 02-44-4102 – Auditing Fees
- 02-44-4820 – LMC Codification Expense
- 02-50-4006 – Outside Professional Service Fee
- 02-50-4032 – Attorneys Fees
- 02-50-4033 – Engineering Fees

Other/Miscellaneous

- 02-44-4014 – Dues/Subscriptions
- 02-44-4015 – Seminars/Meetings
- 02-44-4016 – Travel Expense
- 02-44-4018 – Staff Services
- 02-50-4014 – Dues/Subscriptions
- 02-50-4015 – Seminars/Meetings
- 02-50-4016 – Travel Expenses
- 02-50-4050 – Miscellaneous Expense

Insurance

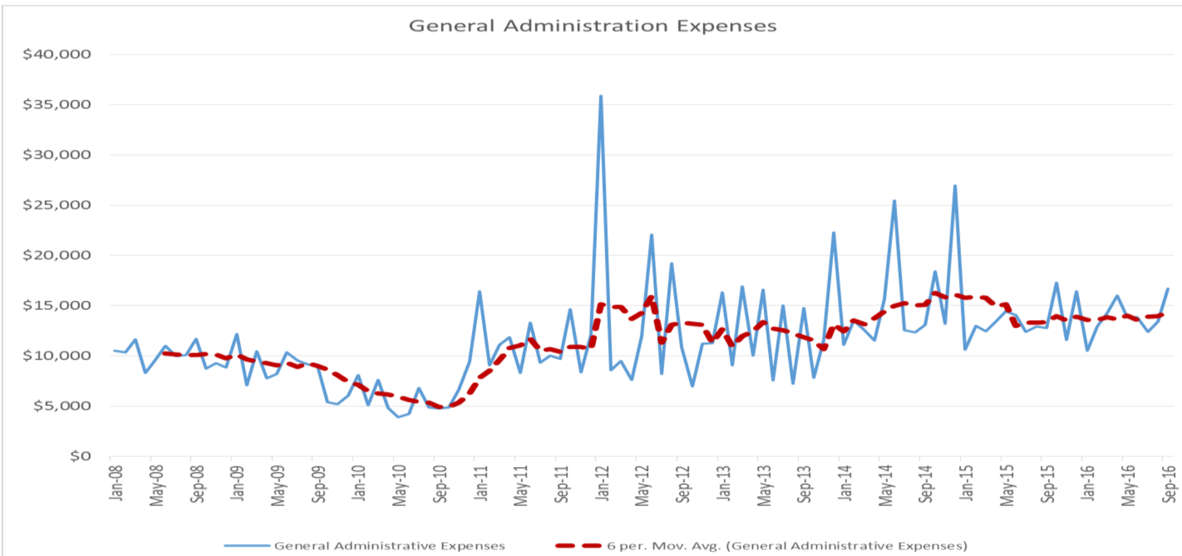
- 02-44-4022 – Unemployment Insurance Expense
- 02-44-4023 – Work Comp Expense
- 02-44-4800 – General Insurance

Allocations from General Fund

- 02-44-8002 – EF's Share Alloc Expenses from GF
- 02-50-4500 – Transfer to GF LESAP

The monthly totals for Administration Expenses swung quite a bit from one month to the next, from a low of $3,945 in May 2010 to a high of $35,890 in January 2012, as can be seen in the figure below. The six-month moving average, however, indicates that the trend moved up in 2011/2012 from 2009/2010 lows, then nearly leveled out after that.

Figure 31: General Administration Expenses by Month

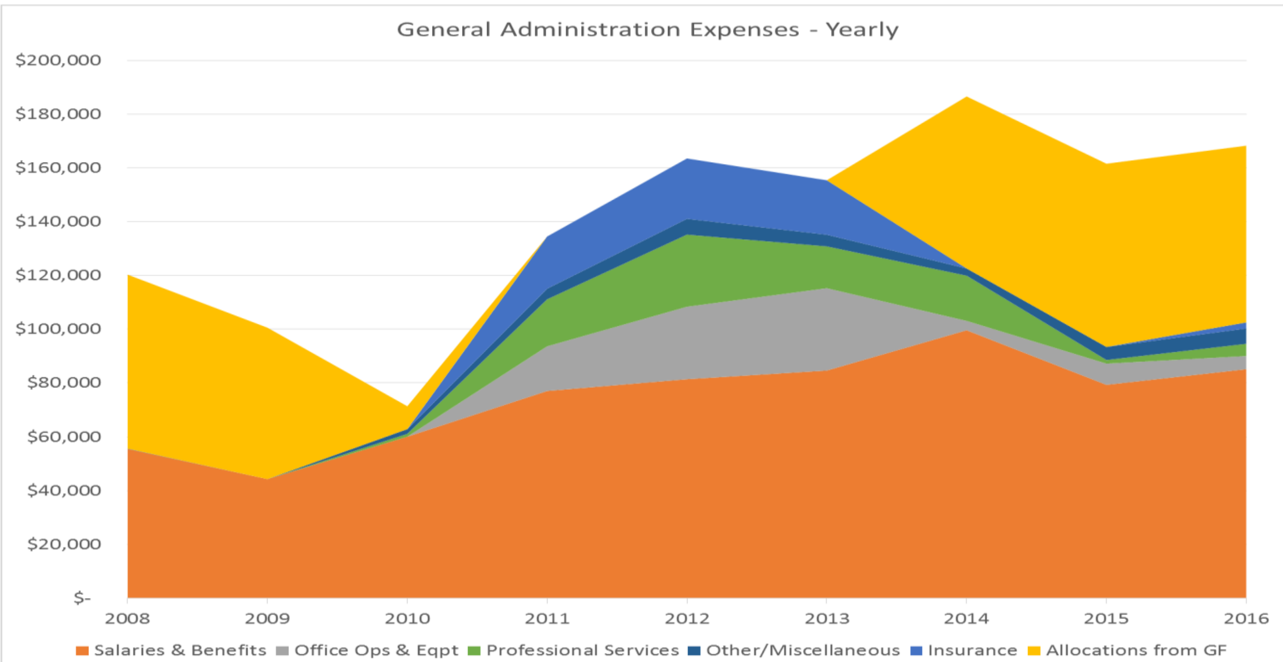


The 'spikes' in administration expenses were largely driven by large one-time outlays, with one exception in January 2012, when a few smaller expenses hit the books in the same month. The largest contributors to monthly totals in these spike months were:

- January 2012 –
  - Worker's Comp Expense ($9,367)
  - General Insurance ($12,662)
- June 2012
  - Employee Insurance – ER ($8,735)
- August 2012
  - Auditing Fees ($3,124)
  - PC Technician Fees ($2,247)
  - Miscellaneous Expense ($2,308)
- December 2013
  - Equipment & Small Tools
- June 2014
  - Full Time Salaries ($14,877, which is more than $9,000 above the monthly average)
- December 2014
  - Outside Professional Service Fees ($14,049)

A better sense for the direction of administration expenses can be seen by analyzing yearly expenses (see chart below). The earlier DSCR discussion pointed out an increase in Operating Expenses in 2011 and 2012, and as seen in the chart above, annual administration expenses – a component of total operating expenses - climbed substantially in these years, then remained level to slightly higher. Due to the accounting changes through the study period, whereby some expenses were aggregated into “allocations from the General Fund” in some years and separated out in other years, it is difficult to draw many more conclusions, outside of noting a steady increase in salaries and benefits. The change from 2008 to the end of the period represents a compound average growth rate (CAGR) of 5.5% per year, or 9.8% since the lowest level in 2009.

Figure 32: General Administration Expenses by Month



Distribution/Maintenance Expenses

For the analysis of distribution/maintenance expenses, individual distribution/maintenance accounts were grouped as follows:

Salaries & Benefits:

- 02-65-4002 – Maintenance Salaries
- 02-65-4024 – Payroll Taxes – ER
- 02-65-4025 – Employee Insurance – EF
- 02-65-4026 – Retirement Contribution – ER

Outside Professional Services

- 02-65-4006 – Outside Professional Service Fees

Electrical Hardware

- 02-65-4038 – Equipment & Small Tools
- 02-65-5001 – Transformers
- 02-65-5002 – Meters: Replacements, Sockets, Test
- 02-65-5005 – Wire: Crossarms, Connectors, Poles
- 02-54-5014 – Substation Maintenance & Supplies

Other Equipment

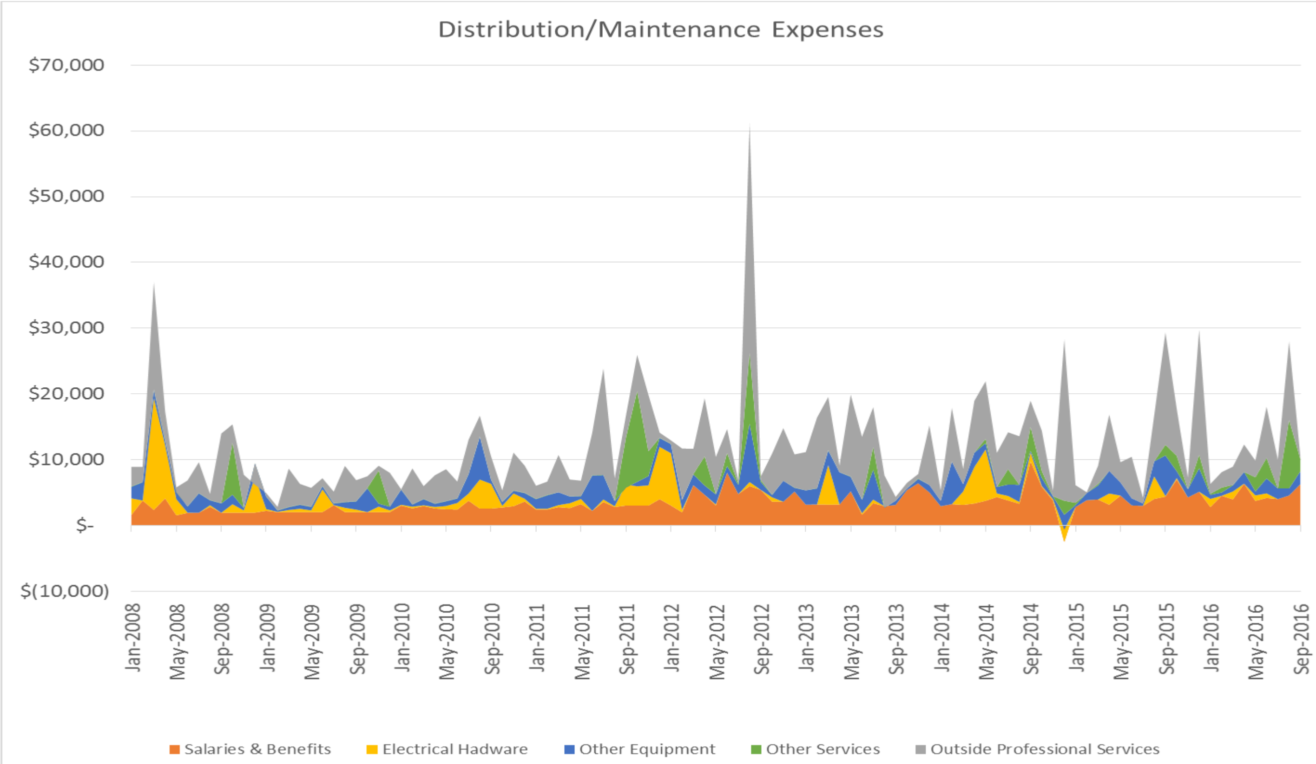
- 01-65-4011 – Equipment Maintenance
- 02-65-4027 – Maintenance & Supplies
- 02-65-4029 – Vehicle Maintenance Expense
- 02-65-4030 – Gasoline, Oil, etc.
- 02-65-4035 – Uniforms Expense
- 02-65-4041 – PC, Software & Printers

Other Services

- 02-65-4020 – Natural Gas Service
- 02-65-4021 – Telephone Service
- 02-65-4050 – Miscellaneous Expense
- 02-65-4306 – Tree Trimming

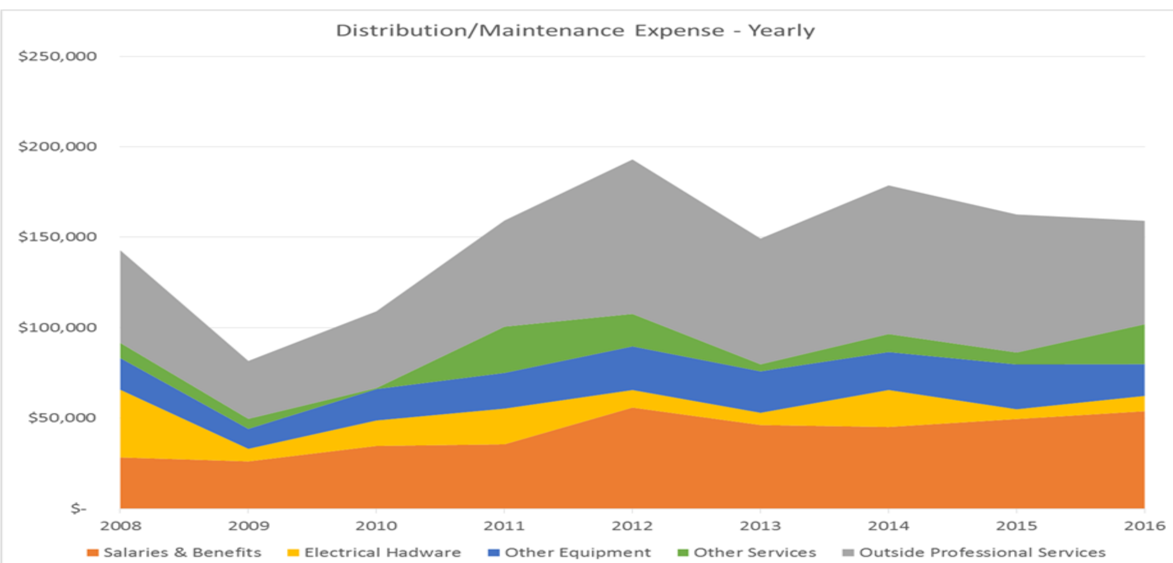
As the Figure 33 shows, while monthly fluctuations in distribution/maintenance expenses are significant, monthly swings appear to be driven largely by changes in amounts billed to Outside Professional Services. The work reflected in these billings may actually be steadier than what appears on the billings. This question is for the Town of Lyons to consider/manage.

Figure 33: Distribution/Maintenance Expenses by Expense Category



Further, total yearly distribution/maintenance expenses climbed from a low in 2009 through 2012, then stayed in a small range between $150,000 and $180,000, with modest fluctuations around an average of $163,000 in the last four years (see Figure 34).

Figure 34: Distribution/Maintenance Expenses (Yearly) by Expense Category



On a year-to-year basis, the breakdown of costs is remarkably consistent. A little less than one-third of expenses are in Salaries & Benefits, about 35-45% are in Outside Professional Services, and the remainder is dominated by Other Equipment (transformers, meters, wire, substation equipment). The spike in Other Services in 2016 can be attributed to a large Tree Trimming expense recorded in August (see Table 6).

Table 6: Distribution and Maintenance Expenses

	2008	2009	2010	2011	2012	2013	2014	2015	2016 (fcst)
Salaries & Benefits	20%	32%	32%	22%	29%	31%	25%	30%	34%
Outside Prof'l Svcs	36%	39%	39%	37%	44%	47%	46%	47%	36%
Electrical Hardware	26%	8%	13%	12%	5%	5%	11%	3%	5%
Other Equipment	12%	14%	16%	12%	13%	15%	12%	15%	11%
Other Services	6%	7%	1%	16%	9%	3%	6%	4%	14%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%
Total Maint. (000s)	$143	$82	$109	$159	$193	$149	$179	$163	$159

Finally, the utility's annual costs were compared to selected benchmarks as provided by American Public Power Association. APPA surveyed 188 of the country's largest public power systems, yet was able to include utilities down to those with just a few thousand customers. The most recently available benchmarks are median values, recorded as of 2013. It is important to note that the survey included utilities that own generation and utilities that do not.

A comparison of the Town's costs with those of peer utilities indicates that the Town's Distribution/Maintenance costs per customer fall roughly in line with those of other utilities. The Town's Administrative costs per customer, however, are well below the "typical" level experienced by peer utilities. When comparing total Operations & Maintenance costs on a scale per kWh sold, the Town's expenses (including depreciation and amortization costs) are running well below the peer rates. See Table 7 below.

Table 7: Industry Comparative Costs

	APPA RATIOS (2013)		TOWN OF LYONS		
	2-5K Customers	**Southwest**	**2013**	**2016**	**2020**
DISTRIBUTION O&M EXPENSE PER RETAIL CUSTOMER	$ 161	$ 127	$ 142	$ 141	$ 149
CUSTOMER ACCOUNTING, SERVICE, SALES EXPENSE PER RETAIL CUSTOMER	$ 81	$ 50			
ADMINISTRATIVE AND GENERAL EXPENSES PER RETAIL CUSTOMER	$ 389	$ 187			
TOTAL "ADMINISTRATIVE" EXPENSE PER RETAIL CUSTOMER	$ 470	$ 237	$ 148	$ 149	$ 140
TOTAL O&M EXPENSE PER KWH SOLD	$ 0.075	$ 0.068	$ 0.031	$ 0.035	$ 0.035

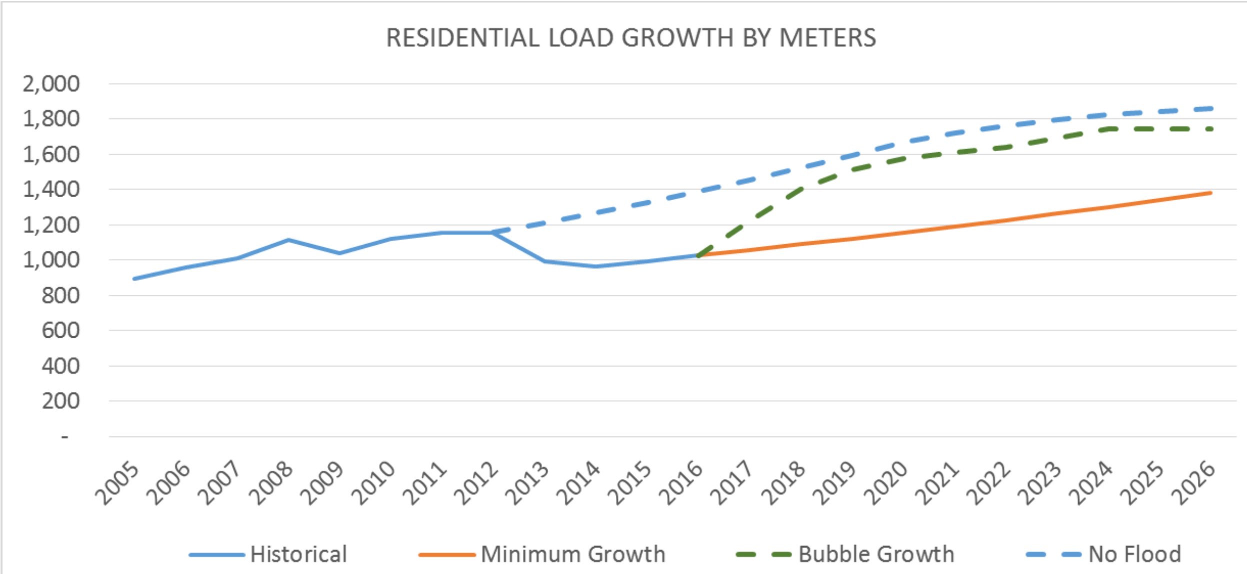
VI. Ten Year Revenue Requirements: 2016 to 2026

A. Load Projection

The Town of Lyons is on a path of recovery and the aggregate of retail sales in 2016 is on track to show growth of 1.1 percent over 2015. As an attractive and lively community located on the road to Rocky Mountain National Park, Lyons is poised to resume its growth.

The volume of annual energy from residential loads took an 8 year setback due to the flood event; however, energy consumption should return to its 2012 level by 2020 at the latest. The Town's recovery appears to be driven by Residential customers, which bounced back to a 3.3 percent annual growth rate after 2014. Over the long run, residential electric load should continue growing at an annual rate somewhere between the more recent 3.3 percent and the longer-term 6.0 percent averaged between 2005 and 2012. Long term residential growth will be limited by the Town's footprint, being constrained by its topology, and the Lyons Area Comprehensive Development Plan regulations. It is therefore reasonable to assume a slower growth in the outer years when housing development will gradually require more multi-family housing and land division.

Figure 35: Residential Load Growth Forecast



One possible approach to the forecast would have the residential accounts catch up to near pre-2013 numbers, labeled here as a "bubble" growth pattern, then slowdown in the outer years as illustrated by the dash green line in Figure 35. Alternatively, it is safer to estimate that the growth rate should average, at a minimum, three percent per year - or roughly half of the pre-flood growth rate. From a utility planning viewpoint, the lower three percent annual growth forecast is more conservative because it limits the annual increase in utility revenues; any growth in excess of the forecasted minimum will benefit the utility with higher revenues from Electric Community Investment Fees and power sales, offset by proportional costs of electric energy and capacity, plus fixed overhead. This second, more conservative, approach (three percent growth) is the one used for the remainder of this report.

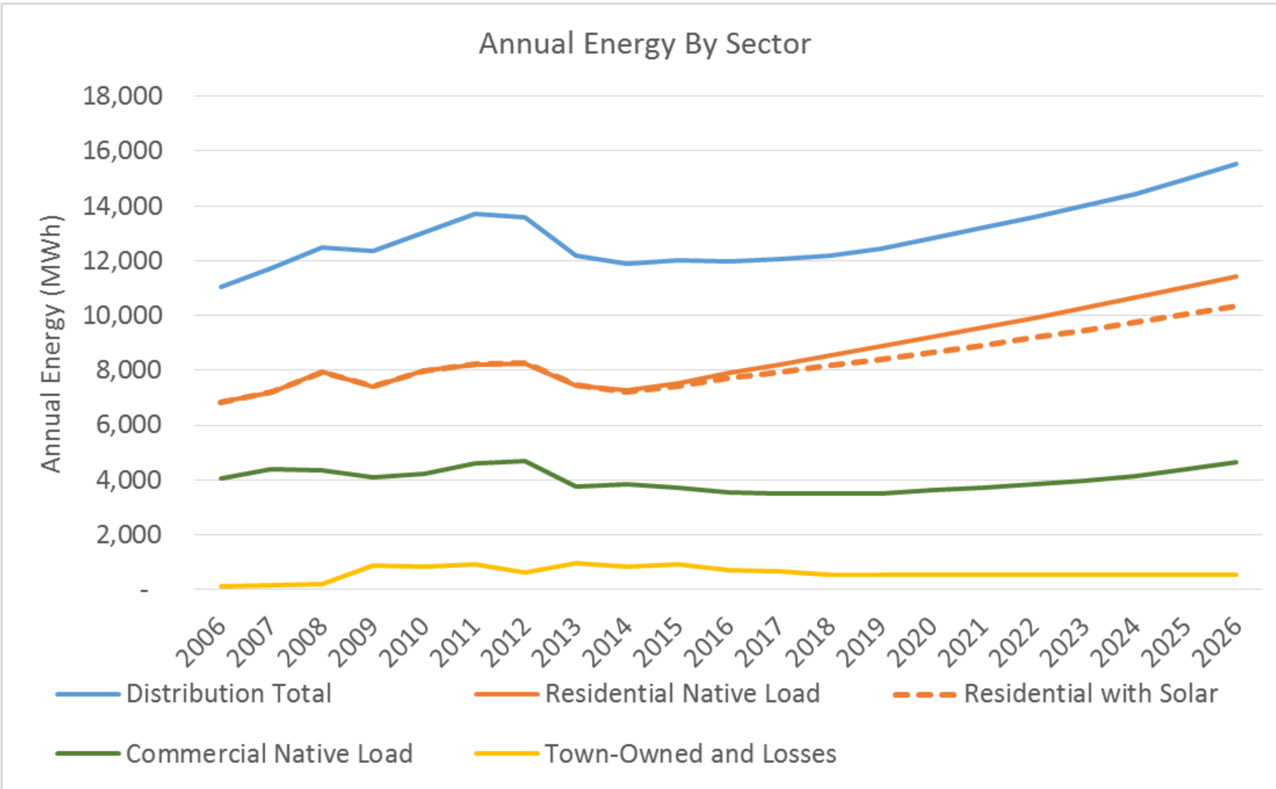
Non-residential retail loads (exclusively secondary commercial accounts), however, are showing a continued decrease in retail electric energy usage. Unlike residential customers, commercial accounts depend on the reliability of the Town's infrastructure (roads, electricity, water and waste water) to remain competitive against similar businesses in Longmont and Boulder. Nevertheless, with the Town's population poised to increase again, there will be a need for additional local service businesses in the near future. Non-residential load in 2016 is on track to approximately equal that of 2005, an 11 year gap to close. Assuming one more year of decline in 2017, estimated at two percent, followed by two years of stabilization, then a pick-up in growth back to the long-term three percent rate, the non-residential load should grow back to its 2012 level of retail electric volume by 2026.

The rapid development of solar Distributed Energy Generation witnessed since 2013 may affect the energy growth by masking some of the residential native load. Although this was true through 2016, the upcoming enforcement of MEAN's Schedule M agreement will result in a reduction of the compensation for excess solar generation from Net Metering rates to avoided generation energy rate[23]. Nonetheless, the orange dash line in Figure 36 illustrates the effect of

[23] As filed by MEAN with FERC under PURPA rates.

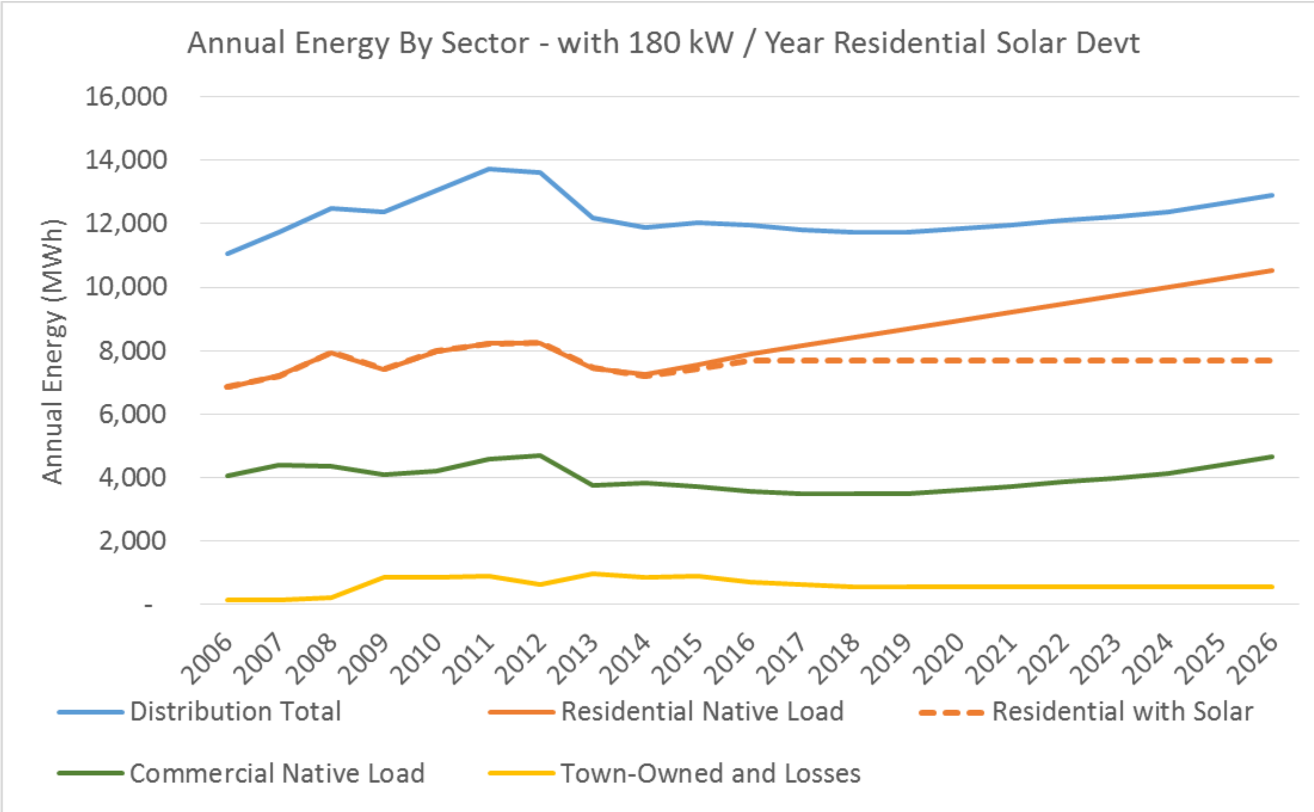
solar development on residential net load, given the assumption that solar rooftop generation would develop at a rate of 60 kW per year, approximately 6 kW per new home annually, for a total capacity of 730 kW in 2026. Under this assumption, the annual residential energy growth rate would lag behind the native load by 0.80 percent on average.

Figure 36: Load Energy Growth Forecast



It would require an annual development of 180 kW of PV solar to stall the minimum three percent load growth forecast as shown in Figure 37. Under this scenario, the installed solar capacity would reach 1,931 kW in 2026.

Figure 37: Forecasted Energy Growth With 180 kW / Year Residential Solar Devt



As a word of caution, excessive solar development is not a sustainable policy as it can collapse the total load during the noon hours of the day; given that capacity and overhead costs still apply, the expectation of a Net-Metering credit from excess solar generation would either create a significant financial burden on retail accounts that do not have solar or, in the extreme, bankrupt the utility.

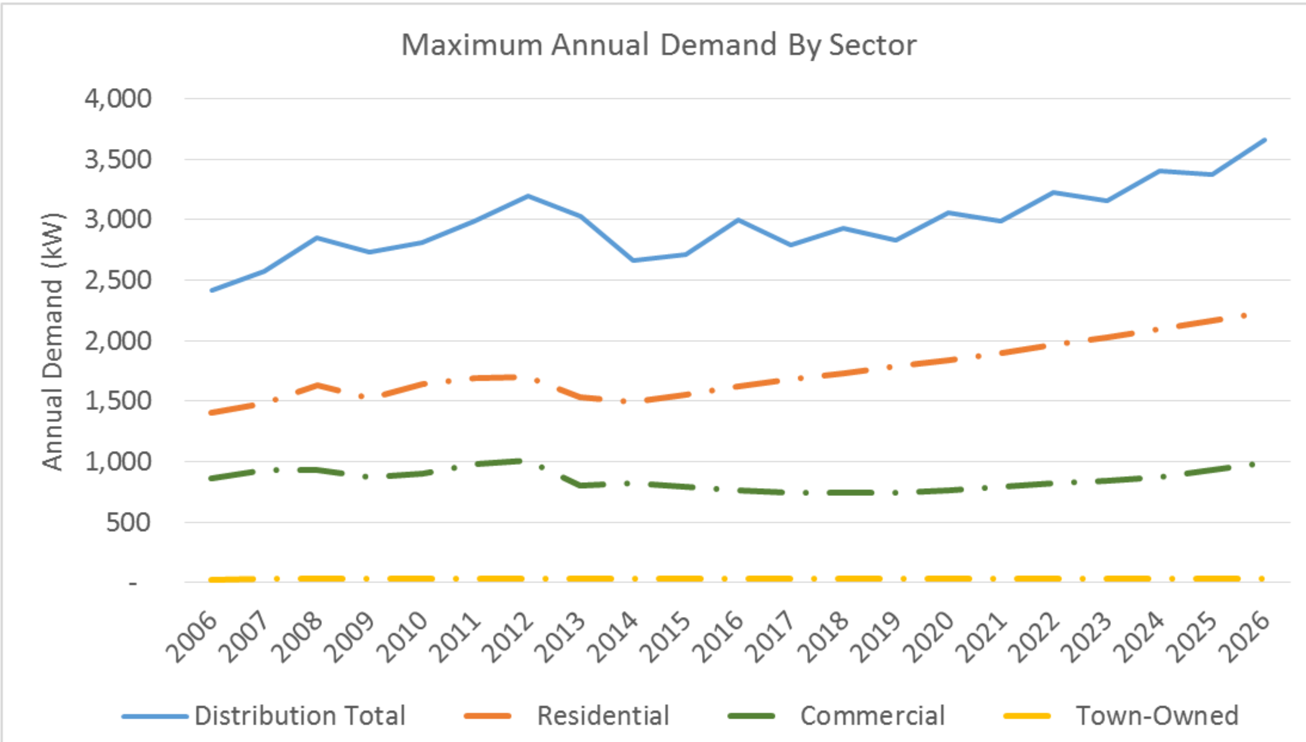
Lastly, the Town-Owned load is likely to remain stable through the years, with a projected modest growth of one percent annually. The reasons for load stability are:

- Upgrade or replacement of Town-Owned facilities will likely involve energy conservation measures.
- The Town is not the County seat, and thus does not require additional campuses.
- The Town's acquisition or development of assets is limited to parks and street lights.

In summary, the Town's total load energy is forecasted to grow at a minimum rate of 1.4 percent in 2017, 2.0 percent in 2018 and 2019, 3.0 percent until 2024 and 3.8 percent until 2026.

Residential load was estimated from proxy hourly profiles to determine the maximum demand for residential and non-residential loads. Applying the average load factor by customer class to the minimum growth energy forecast yields the peak demand forecast shown below in Figure 38 (the 100 kW oscillation in total demand forecast is due to the retail class aggregation forecasting algorithm which alternates summer peaks between July and August).

Figure 38: Load Demand Growth Forecast



While the development of PV solar will affect the energy forecast, it will not change the peak demand under today's technology. Recall that the total system peaks occur in the morning and evening; PV solar, however, will achieve its maximum output levels around noon - in the middle of the solar day. Therefore the forecasted demand will remain unaltered by the inclusion of PV solar in the system, at least at the current and projected levels of solar penetration.

B. Power Purchase Forecast

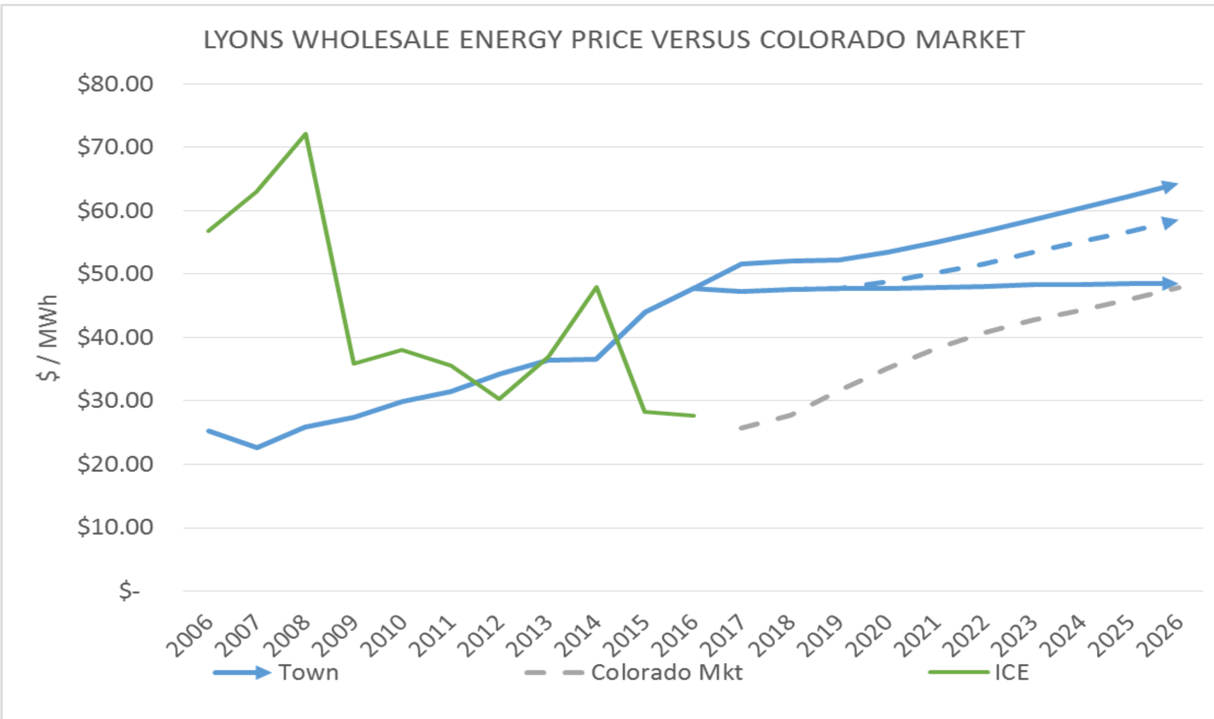
By nature, the procurement of energy will follow the total load, net of Distributed Generation, while capacity procurement will follow the "gross total load". Recall that PV Solar is not yet able to economically provide capacity.

1. <u>Energy Cost Forecast</u>

Based on history, the Town benefits from competitively priced wholesale energy supplied by WAPA-RMR and MEAN. Some of the energy procurement may be reduced by the development of pre-2017 Solar generation, which is grand-fathered under the Town's Net-Metering tariff. Excess solar generation from post-2016 development will be purchased by MEAN at the avoided generation rate but the Town will remain obligated to purchase all its energy from MEAN as per the Schedule M tariff.

The wholesale energy rate, blended between WAPA-RMR and MEAN, is forecast to decrease slightly in 2017 due to the 2016 reduction in Drought Adders from WAPA and reduction in Support Energy price from MEAN. With a portfolio of resources dominated by coal, nuclear and hydropower, Lyon's energy cost should be hedged against natural gas price swings.

Figure 39: Energy Cost Forecast ($/MWh)



The long term forecasting of energy pricing is particularly challenging because it is currently driven by federal regulations such as EPA's Clean Power Plan, developments in carbon Cap-And-Trade markets, and the uncertainty of tax incentives for renewable energy generation.

Historically, the Town's energy price was competitive against the Colorado wholesale market until 2015. Looking beyond 2017:

- On the low side, illustrated in Figure 39 above with the lower of the two solid blue lines, it appears reasonable to expect the Town's energy price, largely driven by MEAN, to remain stable until 2026, while forecasted wholesale market prices catch up with MEAN.
- On the high side (the higher solid blue line), MEAN could resume its pre-2015 price growth in 2018; this forecast alternative would place MEAN's energy too far above wholesale market projections to be realistic and avoid losing Schedule M members.
- A third option (the blue dotted line), recognizes the 2016 reduction in MEAN's Support Energy price, the 2017 reduction in WAPA's Drought Adder and a 4.20 percent average

increase in MEAN's energy price, for a total average increase of 3.00 percent per year starting in 2021.

Based on the third option above, Lyons's energy procurement cost is forecasted to increase at an annual average rate of 5.1 percent between 2016 and 2026, driven by increases in both total load and MEAN's energy prices.

2. Capacity Cost Forecast

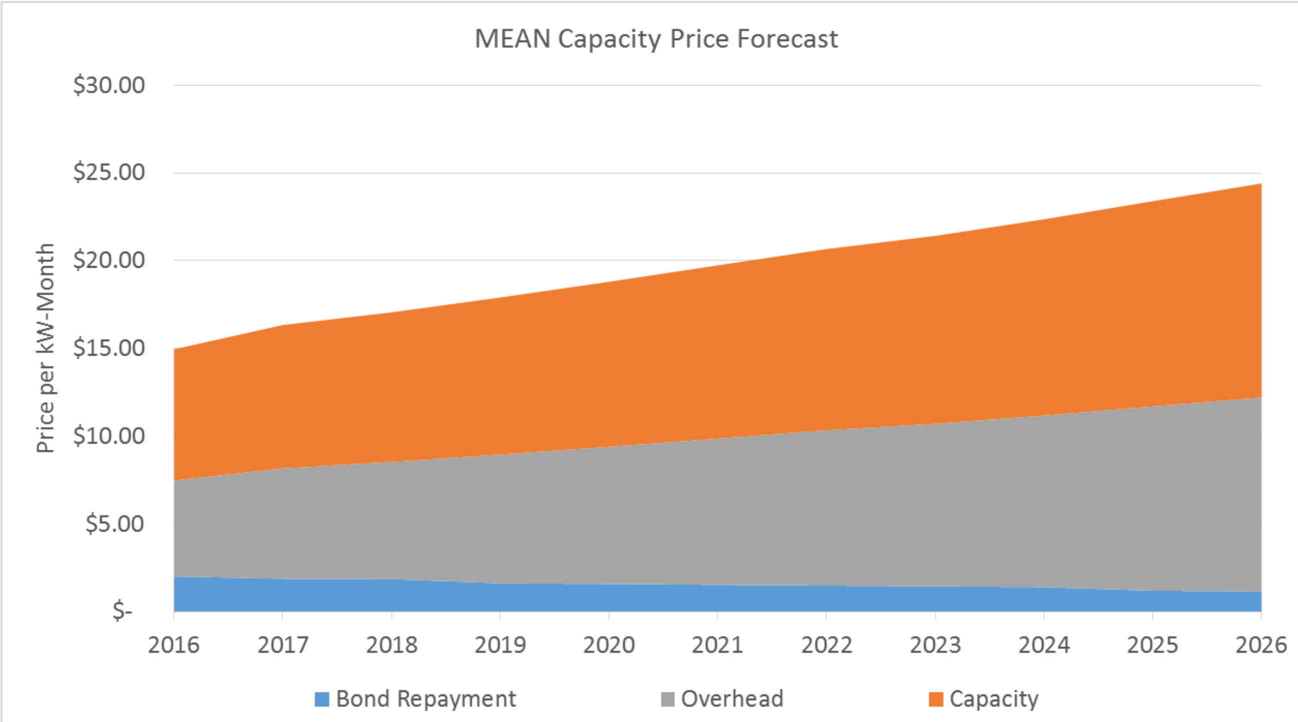
Forecasted capacity costs remain near zero in Colorado for the foreseeable future due to excess generation capacity. The announced retirement of the Dave Johnston Units 1 through 4 in Wyoming will result in a capacity reduction of 818 MW for the eastern WECC market in 2027.

Until then, MEAN will continue collecting its capacity payments under the fixed monthly Cost Recovery Charge for the foreseeable future. It is reasonable to assume that MEAN capacity price will be driven by the debt service repayment commitment on MEAN's 2013 and 2016 series bonds and the operation overhead costs. The MEAN capacity price forecast is based on the following assumptions:

- The Town's load continues representing 0.50 percent of MEAN sales and is allocated that percentage of the bonds repayment.
- The Town does not partake in other projects financed by MEAN in the future.
- MEAN's costs for capacity commodity increase at a 7 percent annual average.
- MEAN's operations overhead costs increase at an 8 percent annual average.

Based on the above assumptions, MEAN's capacity price is forecasted to increase by 9.2 percent in 2017, followed by an average annual price increase of 4.6 percent. Figure 40 shows the forecasted capacity price, broken down by components.

Figure 40: MEAN Capacity Price Forecast

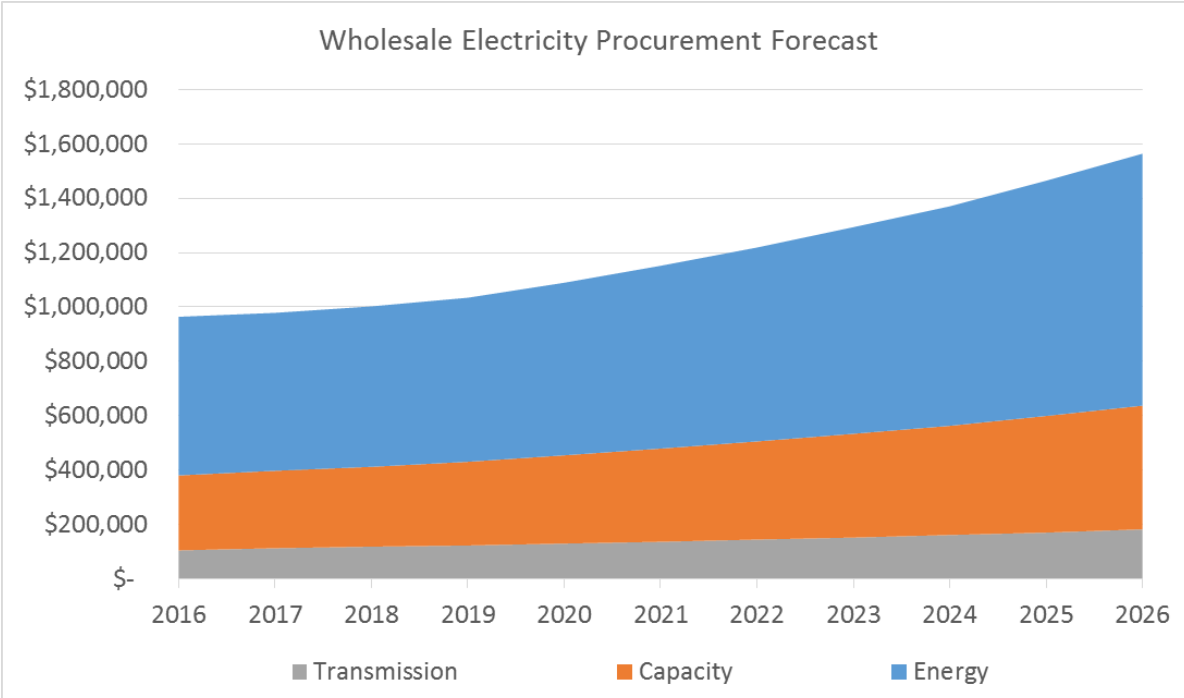


WAPA will reduce its capacity drought adder in 2017. Its capacity price is largely based on fixed Operation and Maintenance for its hydropower plants, with a planned increase of 4.00 percent per year.

3. Town's Cost of Wholesale Electricity

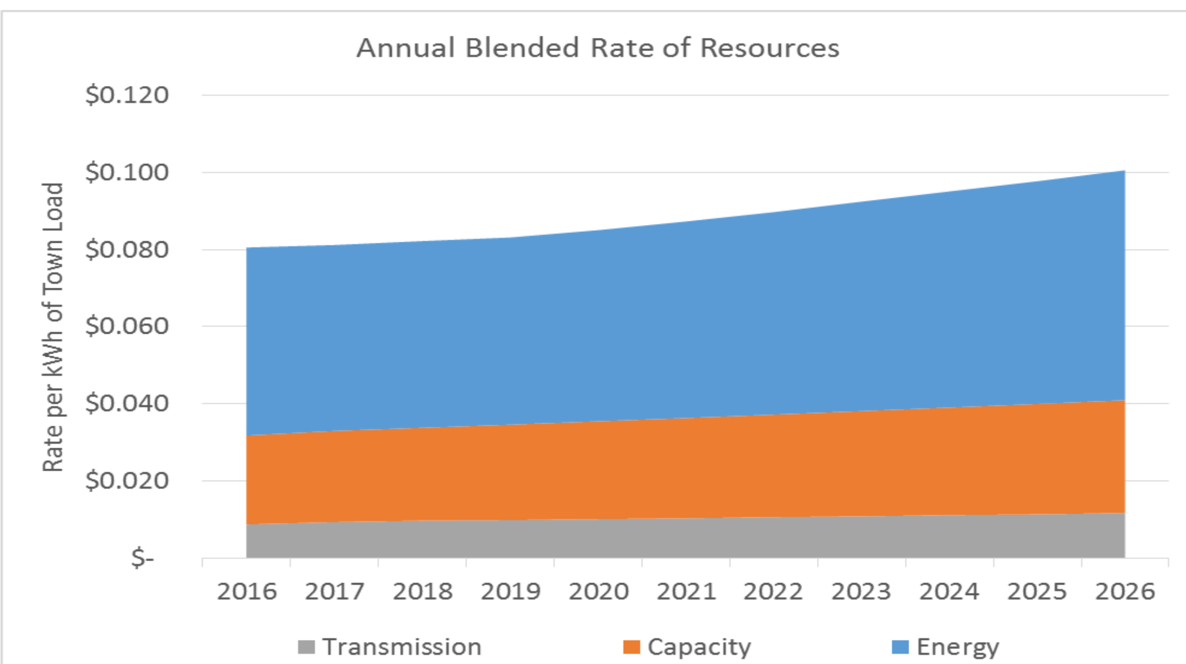
The Town's forecasted wholesale energy cost is based on the energy, capacity and transmission cost forecasts. Figure 41 reflects a "business as usual" budget forecast with an overall average annual increase of 4.85 percent. The budget is driven by the load growth forecast, compounding the price increases, to yield a gradually steeper budget increase.

Figure 41: Electricity Procurement Cost Forecast



However, when applying the forecasted electric cost to the Town's total retail load, the blended price increase remains below 3 percent per year, averaging 2.42 percent annually between 2017 and 2026.

Figure 42: Blended Electricity Rate Forecast



4. Town's Cost of Electrical Service

Based on the above estimates of price increases and load forecasts, the utility's cost of providing electric service to the Town is expected to increase until 2024, when the 2003 bond will be fully repaid. Figure 43 shows the budget forecast on a revenue basis. Sale of power is driven by the larger of a 1.25 DSCR or a $50,000 annual revenue margin.

Figure 43: Revenue and Cumulative Costs - Revenue Basis

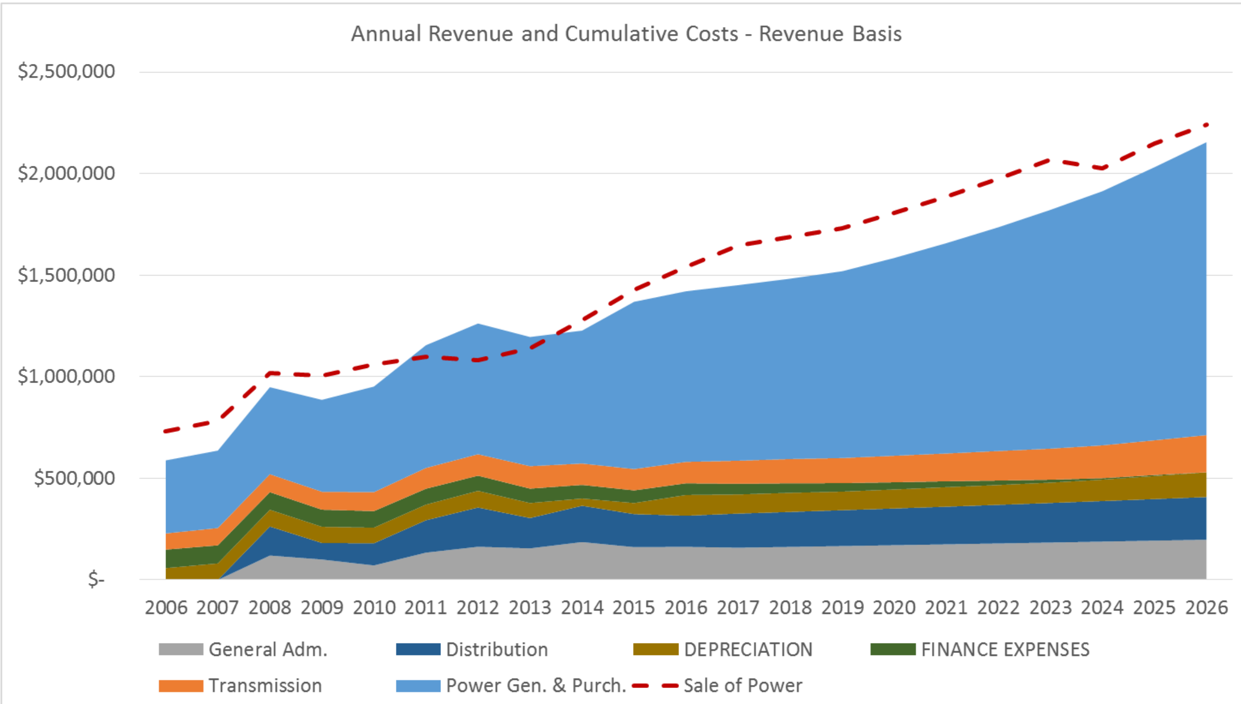
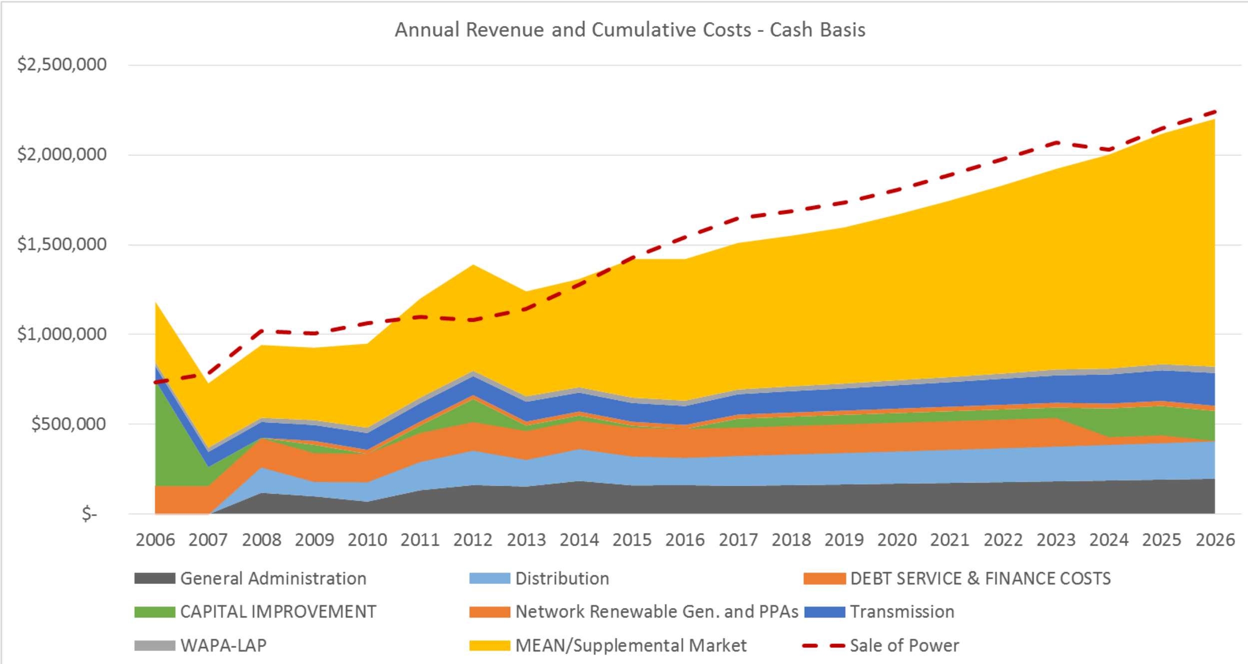


Figure 44 shows the same but on a cash basis.

Figure 44: Cumulative Costs Forecast - Cash Basis



Under the assumed growth forecast, blended rates are showing to stabilize after 2018.

Figure 45: Blended Electric Rates

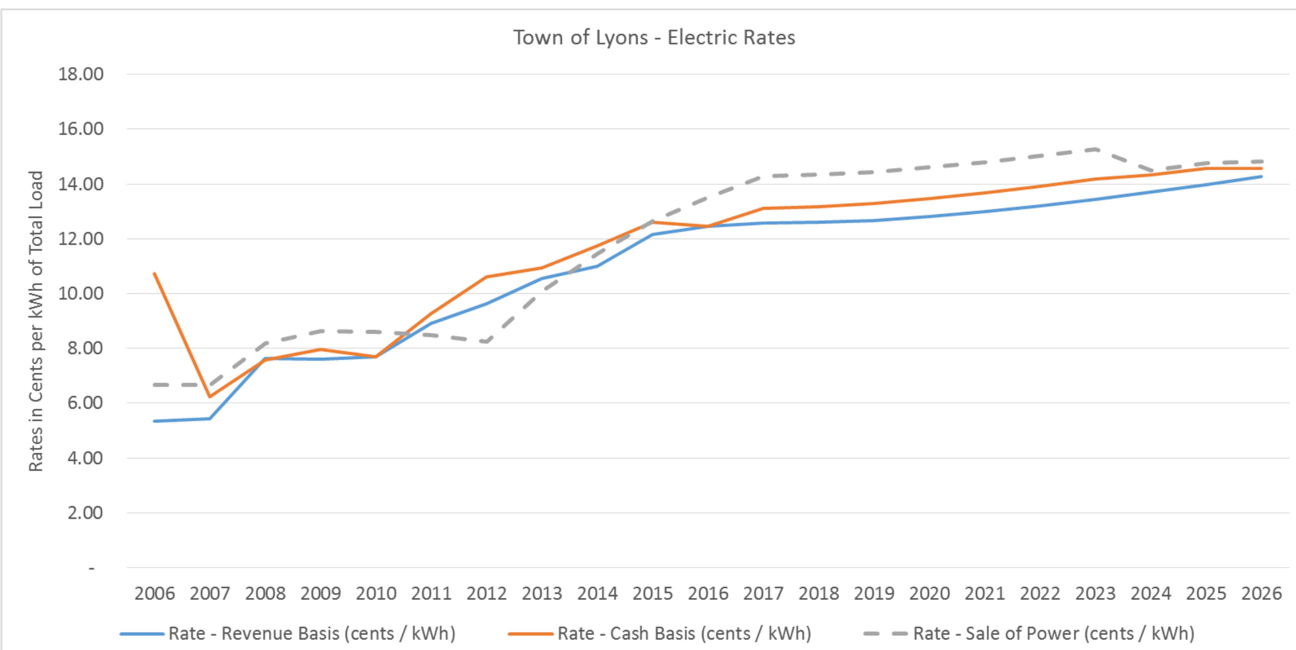


Figure 45 above shows three forms of blended rate. On a cash basis, the rate is calculated as the annual total of expenses, debt service repayment and capital improvement budget over the annual load in kWh. The revenue basis rate is derived from operating expenses, similar to the cash basis, but substituting depreciation and finance expenses in place of capital expenditures and debt repayment. On a sale of power basis, the rate is further constrained by a minimum 1.25 Debt Service Coverage Ratio and/or a $50,000 minimum revenue margin. Tables 8 and 9 below show that the Town's electricity price increase is driven by energy and capacity purchases from supplemental market procurement. Other cost factors remain constant under the load growth assumption.

Table 8: Breakdown of Electricity Price - Revenue Basis (Cents / kWh)

	POWER GEN & PURCH	TRANSM.	GENERAL ADMIN	DISTRIBUTION	CUMULATIVE DEPREC.	FINANCE EXPENSE	NET INCOME	TOTAL
2006	3.27	0.73	-	-	0.53	0.83	1.34	**5.35**
2007	3.26	0.73	-	-	0.69	0.76	1.24	**5.45**
2008	3.45	0.71	0.97	1.15	0.66	0.70	0.57	**7.64**
2009	3.89	0.76	0.86	0.70	0.68	0.72	1.03	**7.62**
2010	4.21	0.76	0.58	0.88	0.62	0.66	0.89	**7.71**
2011	4.66	0.79	1.04	1.23	0.59	0.60	(0.43)	**8.91**
2012	4.91	0.81	1.25	1.47	0.63	0.57	(1.38)	**9.64**
2013	5.61	0.97	1.37	1.32	0.65	0.63	3.00	**10.55**
2014	5.86	0.94	1.67	1.60	0.32	0.60	0.47	**10.99**
2015	7.31	0.93	1.43	1.44	0.48	0.55	0.51	**12.15**
2016	7.35	0.92	1.43	1.35	0.90	0.51	1.07	**12.45**
2017	7.51	0.98	1.37	1.45	0.81	0.45	1.70	**12.59**
2018	7.56	1.02	1.38	1.46	0.79	0.40	1.74	**12.61**
2019	7.66	1.03	1.39	1.47	0.76	0.35	1.78	**12.66**
2020	7.88	1.06	1.38	1.46	0.75	0.29	1.79	**12.81**
2021	8.12	1.08	1.37	1.45	0.75	0.23	1.81	**13.00**
2022	8.39	1.11	1.36	1.44	0.74	0.17	1.82	**13.21**
2023	8.68	1.13	1.35	1.43	0.74	0.11	1.83	**13.44**
2024	8.96	1.16	1.35	1.43	0.75	0.05	0.81	**13.70**
2025	9.25	1.18	1.33	1.40	0.78	0.03	0.80	**13.97**
2026	9.55	1.22	1.31	1.39	0.80	0.00	0.57	**14.27**

Table 9: Breakdown of Electricity Price - Cash Basis (Cents / kWh)

	WIND	WAPA-LAP	MEAN SUPPL. MKT	TRANSMISSION	GEN. ADMIN	DISTRIBUTION	DEBT SERVICE AND FINANCE COST	CAPITAL IMPROVEMENT	TOTAL
2006	-	0.20	3.06	0.73	-	-	1.43	5.31	**10.74**
2007	-	0.20	3.06	0.73	-	-	1.33	0.90	**6.23**
2008	-	0.19	3.26	0.71	0.97	1.15	1.29	0.02	**7.59**
2009	0.19	0.23	3.46	0.76	0.86	0.70	1.36	0.40	**7.97**
2010	0.18	0.24	3.79	0.76	0.58	0.88	1.27	-	**7.69**
2011	0.17	0.24	4.25	0.79	1.04	1.23	1.23	0.32	**9.26**
2012	0.17	0.23	4.52	0.81	1.25	1.47	1.20	0.98	**10.62**
2013	0.20	0.26	5.15	0.97	1.37	1.32	1.41	0.27	**10.95**
2014	0.20	0.27	5.39	0.94	1.67	1.60	1.40	0.26	**11.73**
2015	0.20	0.26	6.84	0.93	1.43	1.44	1.40	0.10	**12.61**
2016	0.20	0.26	6.89	0.92	1.43	1.35	1.40	-	**12.45**
2017	0.20	0.23	7.08	0.98	1.37	1.45	1.35	0.43	**13.10**
2018	0.20	0.23	7.14	1.02	1.38	1.46	1.33	0.43	**13.18**
2019	0.20	0.22	7.24	1.03	1.39	1.47	1.31	0.44	**13.30**
2020	0.20	0.22	7.46	1.06	1.38	1.46	1.27	0.43	**13.48**
2021	0.20	0.22	7.71	1.08	1.37	1.45	1.24	0.43	**13.69**
2022	0.20	0.22	7.98	1.11	1.36	1.44	1.20	0.43	**13.93**
2023	0.19	0.24	8.24	1.13	1.35	1.43	1.16	0.43	**14.18**
2024	0.19	0.24	8.53	1.16	1.35	1.43	0.30	1.14	**14.33**
2025	0.19	0.23	8.82	1.18	1.33	1.40	0.28	1.12	**14.56**
2026	0.19	0.23	9.13	1.22	1.31	1.39	-	1.11	**14.57**

VII. Observations and Recommendations

A. Minimum Cash Reserve

Minimum cash reserves for the Town's electric utility operations consist of:

- WAPA-RMR credit limit requirement: 5 months of total estimated service charges under the FES Customer's contract for electric service[24].
- 2006 Taxable Bond Debt Service Reserve: 6.27 percent of bond par-value[25].
- 2003 Non-Taxable Bond Debt Service Reserve: 6.27 percent of bond par-value[26].

In addition, the Town's policy adheres to prudent utility practice by maintaining at least three months of cash Operating Reserve, such that the utility can continue to pay its suppliers in the event of a missed retail billing cycle. Table 10 summarizes the minimum recommended and mandatory cash reserve.

Table 10: Minimum Cash Reserve

RESERVE	DESCRIPTION	AMOUNT
2003 NON-TAXABLE BOND DEBT SERVICE RESERVE	Mandatory, restricted cash.	$100,000
2006 TAXABLE BOND DEBT SERVICE RESERVE	Mandatory, restricted cash.	$31,500
	TOTAL RESTRICTED CASH	$131,500
WAPA-RMR 5-MONTH RESERVE[27]	Mandatory. Either placed in trust account with WAPA or included in Operating Reserve	$60,000
LYONS ELECTRIC OPERATING RESERVE	Prudent utility practice – 3 months of operating reserve	$400,000
	MINIMUM NON-RESTRICTED CASH RESERVE	$400,000

The non-restricted cash reserve, when augmented by over-collections, may be used for seasonal rate stabilization. In addition, a multi-year rate stabilization fund could be developed to inoculate retail rates against unexpected costs.

B. 2017 Increase in Sale of Power Revenue

The near term projection of costs suggests that the Town's electric utility will need to increase its revenues by 6.24 percent to meet its 2017 costs. The $96,100 projected increase entails $24,300 for Power Generation and Purchases, $10,700 for utility operations, and $61,100 for

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[24] Western Area Power Administration – Federal Power Customers – Credit Worthiness Procedures, paragraph 3.3.
[25] Estimated from Financial Statements
[26] Idem
[27] Calculated as August – December 2015 costs from WAPA-RMR

Net Revenue Margin. On a cash basis, the Net Revenue Margin would account for a recommended $50,000 Capital Improvement budget.

C. Identification of Deficiencies

The Town's utility shows a history of strength and prudent management. The utility has been steadily recovering from both the disastrous effects of the 2013 flood and the sharp increase in resource costs in 2015. The utility's responses - load stabilization and prudent retail rate increases - have brought the utility's Debt Service Coverage Ratio (DSCR) back above unity in 2015 and above a healthy 1.5 in 2016.

Nevertheless, in the course of this study, EPSIM has identified the following opportunities for improving the utility's robustness.

1. Operations

a) Non-Metered Loads and Losses

As noted earlier, the utility's distribution losses amount to approximately 700 MWh per year, or 5.5 percent of the Town's load. These entail:

- Losses from the substation transformer.
- Losses from distribution transformers.
- Energy consumed by non-metered loads, including street lights and Bohn Park heating.

The estimated cost impact to retail customers of these "losses" averages $65,000 per year. Assuming that half of these losses[28] are from the non-metered Town-owned loads, the electric utility has an opportunity to re-allocate approximately $30,000 annually, currently born by retail customers, by billing these charges to the Town itself. The Town may then use its own guidelines for allocating such costs to its own revenue base.

b) Substation-Level Data Acquisition

EPSIM recommends that the Town arrange to access the Daugherty Substation meter readings directly for the following purposes:

- To facilitate shadow-calculation of invoices from MEAN.
- To better understand distribution losses and parasitic loads in comparison with the aggregated retail load.

[28] Based on known losses at the Daugherty substation transformer and assuming 97 percent efficiency for distribution transformers.

- To better understand the timing of peaks and thereby develop actionable demand reduction plans.

c) *Utility Budget Planning*

Figures 43 and 44 illustrate how the utility's revenues did not meet the cost of services between 2011 and 2013. The Debt Service Coverage Ratio suffered significantly during these years. EPSIM recommends that the Town, if it does not do so already, generates an operation report and reviews its utility's load, revenues and expenditures at least quarterly. Quarterly operations reports will inform the annual budget, retail rate making and cash flow reconciliation processes.

d) *Wholesale Resource Procurement*

The Town receives its energy and capacity resources from WAPA-RMR and MEAN.

WAPA will renew its Base Resource and Firm Delivery contracts in 2024.

- The Town should apply for an allocation increase of Firm Energy and Capacity from WAPA-RMR.
- The Town should attempt to coordinate between WAPA and MEAN, to the extent possible, the shaping and delivery of Base Energy and Capacity during high load hours in order to reduce the procurement of more expensive resources.

Under the MEAN Schedule M contract, the Town agrees to procure all its energy and capacity – beyond WAPA Base Resource and Wind contract – from MEAN.

- The Town should request periodic reports from MEAN, quarterly if not monthly, outlining MEAN's operation costs and revenues, the Town's share and responsibilities, and a 1 to 5 year outlook of MEAN's budget and membership. Such report should be concise and verifiable.
- The Town should engage in a strategy dialog with MEAN to prioritize low-cost resources, identify cost drivers and mitigation opportunities, review opportunities to jointly develop local storage and generation capacity.

The Town should study opportunities for energy storage in order to reduce its peak demand costs. Storage strategies may include:

- Waste Water Plant operation.
- "Smart thermostats" on electric or gas/electric water and space heaters, air conditioning units. Pre-cool/pre-heat commercial and residential spaces.
- Above-ground compressed air storage.
- Small pumped hydropower. For example between the Saint Vrain River and north of 5th Avenue, the 100-foot elevation difference could facilitate a low cost energy storage opportunity.

The Town should consider the cost/benefit of developing local generation for capacity reserve and resiliency. Such developments must be coordinated with MEAN to ensure that they do not violate the Schedule M agreement but, instead, qualify for Capacity Commitment Compensation. Technology opportunities include:

- Micro-turbines, natural gas or biogas fueled.
- In-conduit hydropower, particularly where it can replace pressure-control valves.
- Other hydropower opportunities, if available, including Apple Valley and Button Rock Reservoir.

2. Customers

a) *Retail Metering*

Retail metering is the linchpin in the utility's revenue collection systems. The Town's electric meters may show the following concerns:

- Aging meters may result in a high number of failures. As meters fail, utility staff spends extra time estimating retail invoices, and the cost of unaccounted-for electricity may eventually be borne by other utility customers.
- Energy meters do not allow the utility to measure demand at the retail level, making it difficult, or impossible, to address the utility's rising cost of capacity in an actionable manner.

EPSIM recommends that the Town invest in interval meters[29], with a goal of replacing and upgrading, at least for non-residential accounts, all existing energy meters. New meters can be procured and deployed, starting with the larger accounts, over several years to conform with an annual budget allocation.

As part of the meter upgrade, the Town needs to consider a suitable meter reading methodology and specify the new meters accordingly.

- Manual reading is time and resource intensive.
- Automated Meter Infrastructure (AMI) can be costly and of limited value to the Town, given its compact footprint and relatively small number of accounts.
- Automated Meter Reading (AMR) using a mobile unit still requires driving through each street and downloading the readings to a central database. Yet it seems to be the preferred and most cost-effective approach for public utilities of similar size.

[29] Interval meters should record 15-minute average demand (kW).

b) Limitation in Residential Development – Loss of ECIF Revenue

Since the Town is geographically constrained, the growth of residential accounts will slow down and stop in the next ten to twenty years. This will lead to a potential loss of the ECIF revenue (aka "tap fees"), currently projected to average $135,000 annually.

Arguably, the ECIF is earmarked to cover the new construction and connection costs. However, the distribution assets will require maintenance and upgrades long after installation, especially with the gradual deployment of electric vehicles and the need to increase distribution capacity for night-time charging. The Town may consider shaping its retail rate tariffs so as to make up for the diminishing (forecasted) ECIF revenue.

c) Limitations of Solar Net Metering

The development of distributed solar generation adds an additional rate element in the form of Net-Energy-Metering. Generally, solar generation occurs during the hours when the residences are empty, resulting in most of the generation exceeding the native load. By compensating the excess solar generation at the full retail price, the Town implicitly makes two debatable statements:

- Capacity costs, utility administration expenses and distribution/maintenance expenses do not have enough value to ask the NEM customer to pay for their portion of these costs.

- By receiving energy during the day and returning it after sunset at no additional charge, the community's utility grid could be misconstrued as a de-facto zero-cost, 100 percent efficient energy storage system.

EPSIM recommends that the Town coordinates with MEAN as soon as possible for the purchase of solar generation, in excess of the native loads, according to Schedule M agreement and PURPA rates filed by MEAN.

3. Financial

a) Inter-Fund Transfers, Set-Aside Reserves, Restricted Funds

While the Town maintains separate funds for each "business-type activity", EPSIM recommends that the electric utility maintain its own separate interest earning accounts for:

- Restricted Funds (Debt Service Reserve).

- Operating reserve, including WAPA reserve.

- Capital Improvement - according to a long-term revenue and expenditure schedule.

- (Optional) long-term rate stabilization.

The balance of revenues could either remain in a common account with the other utilities, earmarked to the electric utility, or in a separate checking account.
Also, an alternative to inter-fund transfers might be a regular Payment In Lieu of Taxes to the Town, whereby funds are generated and earmarked to support the local schools or other public beneficiaries.

b) Coordination between capital expenditures and net revenue

In addition to the financial upset caused by the flood of 2013, it appears that the Town over-spent its revenues in 2011 and 2012, both on an accrual basis and on a cash basis. A significant portion of the over-expenditure came from Capital Improvements, $41,000 and $128,000, respectively, in addition to a 20 percent annual increase in administration costs in these two years. Absent the receipt of nearly $400,000 from its insurance, the utility might have experienced financial hardship in 2013 after the flood. These two years resulted in marginal or even negative DSCRs.

EPSIM recommends that the Town weighs carefully any capital expenditure and expense increase against its revenues, both on an accrual and cash basis, in order to:

- Maintain its DSCR above 1.25, which will enhance its credit rating.

- Maintain its non-restricted cash reserve, net of capital expenditures, above a level equal to three months of operations costs.

The Financial Model provided by EPSIM will greatly simplify this analysis and inform any rate increase.

c) Capital Improvement Plan Expenditures

Historically, the Town has roughly matched its depreciation expenses with corresponding investment in Capital Plant & Equipment, except for the substation, as shown in Table 4 above.

Going forward, EPSIM recommends that the Town budget $50,000 annually (in 2017 Dollars) for Capital Improvement projects through 2024, when the 2003 revenue bond will be fully repaid. In 2024, the Town could then increase its annual Capital Improvement budget by an additional $100,000 (in 2024 Dollars). This would provide the Town a total budget of $867,000 by 2026, for a 2017 Net Present Value of $734,000.

To provide for the Capital Improvement expenditures, the Town will need to include a target revenue margin of $50,000 in its annual revenue calculation.

D. Sustainability versus Sale of Utility

The Town's electric utility seems fully recovered from the 2011 – 2013 period. Its DSCR is projected to maintain a healthy level of 1.8 or above for the foreseeable future. Neighboring utilities such as Longmont have shown their support in spite of trying circumstances. At this point, the Town's electric utility is in good shape and appears financially sustainable.

Owning a utility depends on the community's will, interest and perceived value of the enterprise. Selling the utility is a one-way decision, with no recourse, after which the Town's residents and businesses would turn from customers/owners to "rate payers" with no say in the management of the Town's electricity supply.

E. Retail Customers

1. Customer Classes

As of 2016, all the utility's customers are served under secondary voltage service. Customer classes are separated between Residential, Low Income Residential, Non-Residential and Town-Owned. Although meter activation and deactivation may change almost weekly, the Town's make up is summarized in the following Table 11.

Table 11: Approximate Distribution of Retail Classes - 2016

	BY METER	BY ANNUAL ENERGY
RESIDENTIAL	87.7 %	62.2 %
LOW-INCOME RESIDENTIAL	1.8	1.3
NON-RESIDENTIAL	8.5	29.6
TOWN-OWNED	2.0	6.9*

*Includes losses and unaccounted-for energy

The annual effort entailed for retail rate development is kept to a minimum, thanks to the small number of tariffs employed by the utility. The billing limitations of the currently deployed energy meters precludes any form of Time-Of-Use billing. On the other hand, the Town has successfully applied tiered energy rates. The challenge ahead is to address the increasing cost of capacity purchased, without being able to measure retail demand. Declining retail tier rates, such as those employed in current non-residential tariffs, can result in increased demand and lower capacity factor which, in turn, can disproportionately increase the wholesale capacity purchase cost.

The Town may want to add two new retail rates, to separate residential and non-residential solar Distributed Energy Generation accounts.

The blended rate tables for each customer class that follow assume that total costs can be driven by energy consumption, by demand (maximum capacity), or by number of meters, or by some combination of these three metrics. Table 12 below presents the allocations used for this report. The Town Board is welcome to test or refine these assumptions in the Financial Model.

Table 12: Proposed Cost Allocation by Causation

	BY ENERGY	BY DEMAND	BY METER
ENERGY COSTS	100 %	0 %	0%
CAPACITY COSTS	0	100	0
GEN. ADMIN.	50	0	50
DISTRIBUTION	0	50	50
CAPITAL IMP.	0	50	50
TRANSMISSION	0	100	0
DEPR'N & FINANC.	0	50	50

a) Residential and Low-Income Residential

Based on the assumptions discussed above and the corresponding data inputs made to the financial model, the blended cost of the utility's services, per kWh delivered, can be determined for Residential & Low Income customers.

Table 13: Blended Rates From Cost of Services - Residential and LI

RESIDENTIAL & LOW INCOME (CENTS / KWH)

	Energy	**Demand**	**Meter**	**Total**
2006	2.57	5.11	3.89	**11.58**
2007	2.31	3.18	1.08	**6.58**
2008	3.15	3.13	1.89	**8.18**
2009	3.41	3.33	1.84	**8.58**
2010	3.52	3.36	1.44	**8.31**
2011	3.91	3.94	2.21	**10.07**
2012	4.26	4.60	3.02	**11.88**
2013	4.68	4.94	2.44	**12.07**
2014	4.80	4.89	2.59	**12.28**
2015	5.52	5.33	2.34	**13.19**
2016	5.81	5.31	2.45	**13.56**
2017	5.71	5.81	2.68	**14.21**
2018	5.69	5.90	2.66	**14.26**
2019	5.70	5.98	2.64	**14.32**
2020	5.80	6.09	2.62	**14.52**
2021	5.94	6.19	2.61	**14.74**
2022	6.09	6.31	2.59	**14.99**
2023	6.26	6.41	2.58	**15.26**
2024	6.43	6.91	3.05	**16.39**
2025	6.59	7.01	3.05	**16.66**
2026	6.77	7.15	3.04	**16.96**

Residential and low-income residential loads are well known in their behavior and seasonality. In the near-term, demand-reduction can be achieved with policies or incentives to encourage the use of LED light bulbs, replacement of old appliances (refrigerators, electric dryers, electric water heaters), and widespread use of remote-programmable thermostats.

Newer residential homes tend to include air conditioning units. A/C units are typically turned up in the evening hours, adding a load that cannot be met by DG solar. The evening load during summer months directly affects capacity charges. The Town may consider policies to encourage pre-cooling of the residential space or using smart thermostats, to minimize the impact of A/C units during evening peak demand hours.

Low-income (LI) residential customers are an important part of the community's make-up. They are not likely to participate in Distributed Generation or EV in the foreseeable future. On the other hand, Residential-LI customers may be penalized by living in energy inefficient homes with aging appliances. The Town may want to assess the cost impact on other retail customers of the excess energy and demand from such homes, and prioritize energy-efficiency programs for these accounts. Since many, if not most, of these accounts are rental units, these programs/policies will be most effective if targeted to the landlords who are typically responsible for investments in energy-efficiency.

To set a baseline and compare energy efficiency across residential accounts, the Town may consider normalizing the energy readings for Cooling and Heating Degree Days. The results will outline which accounts need help improving their energy efficiencies.

Over the horizon is the increased deployment of Electric Vehicles (EVs), which will increase nighttime residential loads. Although of probabilistic nature like solar generation, EV charging at night, after the evening peaks, could also increase the residential load factor. The Town may want to negotiate low off-peak energy rates with MEAN in exchange for helping the agency improve its base load generation at night. The Town could also consider the gradual impact of residential EV charging, as it may shift the peak demand hours and thereby impact transmission and capacity charges. Lastly, the Town could study the pending necessity for upgrades to its distribution assets and budget early for such possible upgrades.

b) Non-Residential

For the Non-Residential (Commercial) class, the following table summarizes the annual cost of service in terms of blended rates per kWh.

Table 14: Blended Rates From Cost of Services - Non-Residential

COMMERCIAL (CENTS / KWH)				
	Energy	**Demand**	**Meter**	**Total**
2006	2.57	5.25	1.30	**9.13**
2007	2.31	3.27	0.36	**5.94**
2008	3.15	3.26	0.52	**6.93**
2009	3.41	3.45	0.39	**7.25**
2010	3.52	3.48	0.31	**7.31**
2011	3.91	4.10	0.47	**8.49**
2012	4.26	4.78	0.64	**9.67**
2013	4.68	4.99	0.52	**10.19**
2014	4.80	5.15	0.66	**10.61**
2015	5.52	5.55	0.49	**11.56**
2016	5.81	5.55	0.51	**11.86**
2017	5.71	5.84	0.56	**12.11**
2018	5.69	5.92	0.55	**12.16**
2019	5.70	5.99	0.54	**12.24**
2020	5.80	6.09	0.54	**12.44**
2021	5.94	6.17	0.54	**12.65**
2022	6.09	6.28	0.53	**12.90**
2023	6.26	6.36	0.53	**13.16**
2024	6.43	6.84	0.62	**13.89**
2025	6.59	6.92	0.62	**14.13**
2026	6.77	7.03	0.62	**14.42**

Non-Residential accounts include commercial secondary and home office businesses. It is fair to say that each of the 90-plus accounts represents a unique load profile, with significant per-meter energy and demand consumption.

In general, for this class, solar is more likely to meet the native load and somewhat reduce the afternoon peak. The Town should, nevertheless, reconsider its current Net-Metering policy, as suggested above for Residential accounts. EV charging will have a day-time component which, though more volatile than night time charging, could rightfully motivate additional solar deployment. Lastly, commercial accounts are more likely to provide some form of significant (electric or thermal) energy storage.

EPSIM recommends that the Town prioritize the deployment of interval meters on its non-residential accounts and assign staff resource to analyze each load profile, starting with the larger accounts. Some easy and cost-effective means to reduce peak demand are large compressed air tanks and hot water tanks, and/or pre-cooling or pre-heating office space. Policies and rates can be best developed from a baseline of hourly meter data.

c) *Town-Owned*

Town-Owned loads represent seven percent of the whole community's energy consumption. The Town can test and host new energy and demand reduction policy initiatives, thereby benefiting and leading its community prior to extending successful policies across other rate classes. The following table illustrates the blended cost of services to Town-Owned loads.

Table 15: Blended Rates From Cost of Services - Town-Owned

TOWN-OWNED (CENTS / KWH)				
	Energy	**Demand**	**Meter**	**Total**
2006	2.57	5.34	3.69	**11.60**
2007	2.31	3.32	1.08	**6.71**
2008	3.15	3.23	1.96	**8.34**
2009	3.41	3.43	2.22	**9.07**
2010	3.52	3.46	1.75	**8.73**
2011	3.91	4.07	2.72	**10.70**
2012	4.26	4.75	3.72	**12.73**
2013	4.68	5.10	3.01	**12.78**
2014	4.80	5.05	3.07	**12.92**
2015	5.52	5.44	2.84	**13.80**
2016	5.81	5.44	2.94	**14.18**
2017	5.71	5.91	3.19	**14.81**
2018	5.69	5.99	3.13	**14.81**
2019	5.70	6.06	3.06	**14.82**
2020	5.80	6.16	3.00	**14.97**
2021	5.94	6.25	2.95	**15.14**
2022	6.09	6.35	2.90	**15.34**
2023	6.26	6.44	2.85	**15.56**
2024	6.43	6.92	3.33	**16.68**
2025	6.59	7.01	3.29	**16.89**
2026	6.77	7.12	3.24	**17.12**

Further discussion on Town-Owned loads follows in the next section.

2. Municipal Use of Electricity and Its Billing

EPSIM received very little information about the Town-Owned loads, municipal use of electricity and billings. From verbal statements, it seems that several loads are not metered, including street lights and the Bohn Park electric heating.

Based on its experience with various other electric utilities, EPSIM recommends against non-metered loads and municipal exclusion from electric bills[30]. On the other hand, EPSIM also

[30] Town of Raton, NM, allocated all its electric costs to its retail customers, resulting in unchecked municipal consumption and high retail tariffs.

recommends against applying unjustly high tariffs to municipal loads[31]. A reasonable solution would be for the municipal loads to follow the non-residential tariff.

3. Town's Approach to Customer DG

a) *Data Sources*

In August, 2016 the U.S Department of Energy's Lawrence Berkeley National Laboratory published its annual report of pricing trends for Photovoltaic (Solar) Systems in the U.S., entitled "Tracking the Sun IX: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States". The following discussion draws from that report.

b) *Existing Policy:*

As specified in Town of Lyons Ordinance 923, dated February, 2013, the Electric Utility employs a net metering methodology to manage the flow of money with customers who own their own electricity generation. Typically that generation consists of grid-tied solar/photovoltaic systems. A brief summary follows.

Residential:

- Base charge: Unchanged from the utility's standard rate, and billed each month regardless of energy produced by the Customer-Owned Residential Generation (CORG).

- Energy charge: Customers are charged the standard rate for their monthly <u>net</u> energy consumption, regardless of how much energy was produced by their system at any particular time during the month. In effect, this policy pays the Distributed Generator for his/her solar-generated electricity at the standard retail rate per kWh.

- Interconnection: All systems under 10kW in rated capacity are eligible for the standard net-metering pricing. Systems greater than 10kW in rated capacity are subject to approval by the Town. All customers must complete a written application to the Town Administrator and then enter into an Interconnection Agreement with the Town.

Non-Residential:

Similar to the Residential policy, with one exception: The size threshold at which the system must be approved is 25kW.

c) *Factors Driving Policy*

Looking ahead, the principal factors influencing the Town's policy with respect to Distributed Generation will be:

- Pricing trends

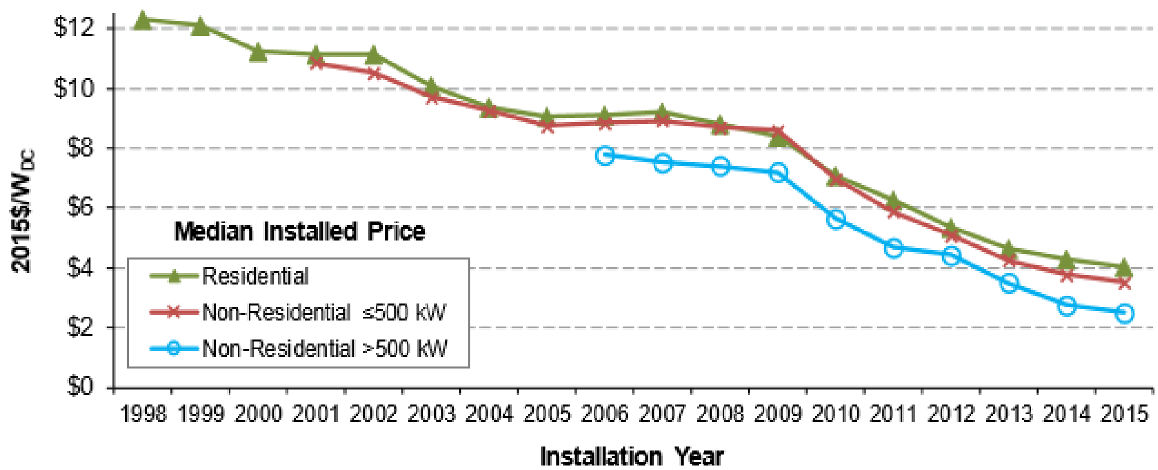
[31] Xcel Energy's street light tariff is inordinately high (over 28 cents per kWh in 2011), for municipally-owned loads running largely during off-peak hours. This tariff could be misconstrued as a hidden tax.

- Grid stability
- MEAN policies
- Town's policies with respect to carbon intensity, sustainability, and local sourcing.

Pricing Trends

The costs of installing solar in both residential and small non-residential locations have been steadily declining for the last 15+ years. On average, national installed prices are down close to a third just since 2011, from approximately $6/W to $4/W.

Figure 46: Average National Solar Installed Costs, by Year



Source: Barbose and Darghouth, Lawrence Berkeley National Laboratories, entitled "Tracking the Sun IX: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States - August 2016"

The recent reductions in installed system costs are due largely to lower non-module costs, including inverters, mounting hardware, installer margins, and local permitting procedures. Solar module prices, which represent approximately 80% of system cost, have remained mostly flat since 2012.

As the number of solar systems installed each year (nationally) grows, solar prices can be expected to continue to fall in the near future, and the Town can anticipate increasing interest in Customer-Owned Generation.

Grid Stability

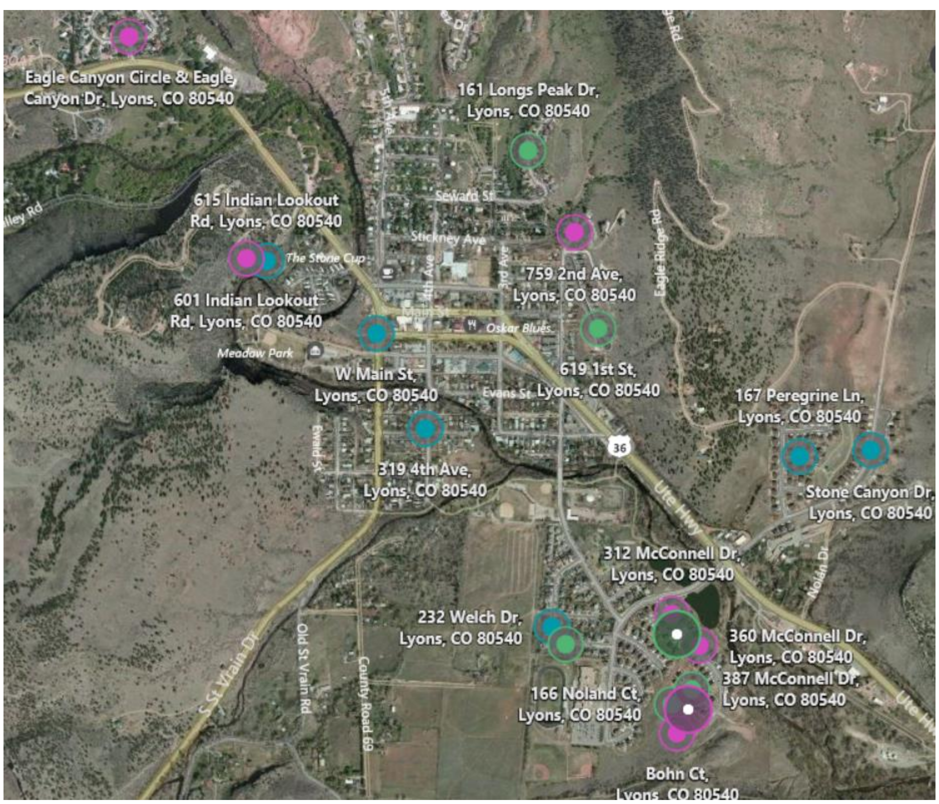
A generally-accepted principle held by the utility industry is that the grid can accommodate the variability of energy generation from solar and wind sources without much change in infrastructure and management processes as long as the variable sources constitute less than 15% of the system's total capacity. Some studies place this limit as high as 30% penetration. Based on the reported capacity of the 25 solar systems currently listed in the Town's reports, these systems have a total installed nameplate capacity of 142 kW (average = 5.7 kW), which can produce approximately 6.7% of the

Town's average electrical load at mid-day in the summer (when output is at its peak). Using publicly available insolation data for the region, these solar systems are estimated to produce an amount of energy equivalent to approximately 0.9% of the Town's annual energy requirement in 2017.

Looking into the future, the extreme possibility exists of every one of the 900 residential customers owning a solar system, in which case the peak output from these distributed energy generators would be approximately 5.1 MW – well above the current system peak of 2.7 MW. The Town will want to look at the design of its distribution grid long before this level of penetration becomes possible. Unless substantial behind-the-meter storage is installed in the bulk of these homes, this penetration will still require capacity from non-solar sources to support the energy requirements of these homes when daylight is not available.

As more distributed generation systems are added to the Town's distribution network it will be important to monitor the extent to which the local circuits can accommodate the added capacity. Based on the addresses of the first 22 out of the total 25 customers with rooftop solar systems, it appears that concentration can be expected in the new developments in and around Lyons Valley Park. Otherwise, the installed base of solar is well distributed across the town's geography, and thus its distribution network. See the map below.

Figure 44: Geographical Distributed of Customer-Owned Solar



Note: The addresses on the map above are very close to, but not exactly, the addresses in the list of existing customers.

Another emerging trend in consumer electrical demand is the small, but growing, use of electrical vehicles (EVs) for transportation, primarily by retail consumers. At their present level of technology, most EVs are being purchased with home-based charging systems, and consumers are charging their EV batteries at home in the evening or overnight, having driven them during the day to and from work or around town. Assuming an average vehicle battery size of 22 kWh[32], an average EV range of 100 miles per charge, an average daily round-trip commute of 50 miles, and a pattern of six round-trips per week (five weekday and one weekend trip), the "typical" EV owner will require approximately 66 kWh per week, or 286 kWh per month, to keep their EV running. This will be an incremental load which the Town will be expected to accommodate. Just a small increase each year of 5 to 10 new EVs can therefore result in additional system loads of as much as 17,160 to 34,320 kWh per year.

Also importantly, as EV penetration increases, so too will the need for the local distribution grid to handle the power requirements of EV home charging. Many home-based Electric Vehicle Supply Equipment (EVSE) units today are designed to pull as much as 20 to 30 amps at 240 volts, or approximately 7 kilowatts, when charging at the more-efficient "Level 2" setting. Any sizeable concentration of EVs in a neighborhood may tax any local transformers that are already at or near their allotted capacity. Should a portion of EV home charging occur on or around the Town's "natural" peaks in the early evening the added load could cause the Town's coincidental peaks and resulting demand charges to rise. At a cost of $15 per kilowatt, just 10 cars charging at Level 2 could potentially increase the Town's demand costs by $1,050 per month. This is not a huge amount, of course, but it is a cost that could grow significantly over time, as EVs gain acceptance in the transportation market.

Finally, there may be interest in the Town of Lyons to install one or more EVSE's on Main Street and/or Broadway as a means of encouraging more of the drivers on their way to/from Estes Park and Rocky Mountain National Park to stop and shop in Lyons. Assuming half-time use of two EVSEs – one on Main Street and one on Broadway - for 12 hours per day in the months of May through November, this could result in an incremental increase in the Town's energy load of approximately 2,520 kWh per month, at a cost to the Town of about $120 per month for the energy consumed[33] and $0 to $105 per month in demand charges, depending on the impact of the EVSE use on coincident peak loads. The Town would then need to develop a policy around who pays these costs and how they are collected.

MEAN Policies

The 2015 FERC[34] Delta-Montrose Decision has clearly stated that Distributed Generation, including PV solar, is governed under the Public Utility Regulatory Policy Act of 1978 (PURPA) and regulated by FERC. Hence the all-requirement purchase price of rooftop solar generation is governed by FERC, not the state or the local utility. Distribution utilities, including MEAN, are subject to PURPA (and FERC), even if not subject to the Federal Power Act. Accordingly MEAN

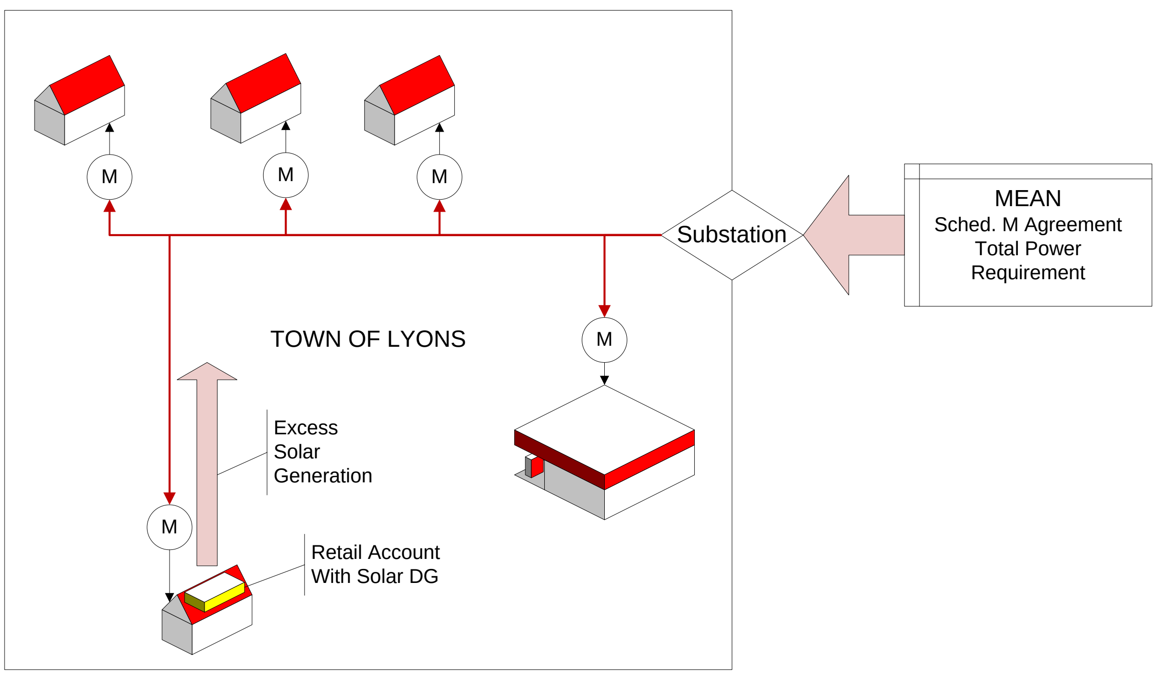
[32] Based on 25 kWh batteries for Nissan Leaf, 20 kWh battery for Chevrolet Volt.
[33] Assumes Level-2 charging, 7 kW load per EV, average energy cost of $0.0477 per kWh, and demand charge of $15 per kW-month
[34] Federal Energy Regulatory Commission

regularly files with FERC the updated definition of applicable avoided cost rate to compensate distributed generation.

MEAN has recently required that a production meter be installed on the solar owner's inverter to monitor the solar production independent of the native load. This requirement follows from Section 3.01(a) of the MEAN Service Schedule M, which states that "MEAN shall sell and deliver to the City [Lyons] and the City shall take from MEAN and pay MEAN for all electric power and energy required by the City for the operation of its electric system, less its WAPA Allocation".

Under the Total Requirements Service, the production meter is to be monitored directly by MEAN, at the Town's cost. MEAN will credit the Town, at the avoided cost filed with FERC, for the net production at the site, i.e., the amount of generation minus the native load. The sale of energy by MEAN to the Town is not diminished by local solar generation. See Figure 47 below. As a result of the MEAN policy, the Town would be in a revenue-neutral position if it passes along to its solar customers the same credit for over-generation that MEAN credits the Town, i.e., the avoided cost rate that MEAN filed with FERC, and the same costs that MEAN charges the Town (such as meter-reading fees). Any additional credits provided to the solar customer, such as those resulting from a net-metering arrangement that credits solar customers, at the retail rate, for excess solar energy generated, are added costs borne by the Town. In this case, the net cost to the Town would be the number of excess kilowatthours produced at the solar site times the difference between the going retail rate and MEAN's avoided cost rate.

Figure 47: Electric Supply and Distribution Schematics



Town of Lyons' sustainability policies

The Town's Environmental Sustainability Plan, updated in 2014, has two goals with respect to the Town's Energy supplies:

- Increase the use of clean energy and transition away from fossil fuels.

- Improve energy and water efficiency of the community's residential, commercial, and institutional building stock

Distributed Generation directly supports the first of these goals and the Sustainability Plan's Case Study presents the Town's net-metering policy as an example of how the Town can "transition… the local energy supply toward renewable energy sources". Additional initiatives are either underway or under consideration for expanding Distributed Generation.

d) Future Policy Recommendations:

The factors above point the Town in the direction of encouraging and supporting increased penetration of the Town's electrical distribution with Distributed Generation sources. This must, of course, be done in a way that is both economically and technically responsible. Accordingly, we recommend consideration of the following:

- Review the Town's net metering policy in light of the MEAN policies discussed above. At low levels of solar penetration the impact on the Town's finances will be small, but net negative. At higher penetration levels, however, the costs can raise concerns about the extent to which non-solar customers are being charged higher rates to cover the Town's costs of supporting solar customers. A review of the current state of the Net Energy Metering (NEM) policies in force around the country will reveal much debate on this topic, with some jurisdictions restricting the availability of NEM to early adopters of solar, and then capping the number of NEM participants, based on a pre-determined percentage of system capacity. At higher levels of penetration, the Town may consider its options for funding the added costs of a NEM policy. Other jurisdictions, however, are electing to maintain their NEM policy without caps, given local public support for clean energy initiatives. The funding of such policies is clearly a matter for the Town to consider.

- While continuing the existing net-metering policy, consider next-generation alternatives to the means by which Distributed Generators are compensated for the energy produced by their systems. While net metering effectively pays DGs a retail rate for DG energy, that rate may not necessarily reflect the true value of the clean energy source to the utility and its local customer base. In addition, the DG retail-rate energy has the effect of offsetting energy from other wholesale sources, which generally enter the distribution system at a lower rate. As a result, assuming these costs are eventually spread over the lower number of kilowatthours billed, non-DG customers end up paying a slightly higher overall cost for the energy consumed by the total Town system. To avoid this "subsidization" effect, two utilities are moving beyond net metering and employing a Value of Solar Tariff (VOST). VOST rates are determined by studying and quantifying additional benefits of the DG energy, such as avoided capacity requirements, avoided line losses, environmental benefits, etc.

- Consider requiring the use of smart inverters for future systems. These are inverters with digital architecture, communication capability, and software that manages the flows of energy across the solar/grid interface. As DG penetration increases, such inverters will be necessary to monitor and manage the impact of DG-sourced energy on the local grid. Manufacturers of inverters, solar installers, and local utilities are already moving in this direction, in recognition of the ever-increasingly complex impact DG energy has on grid operations and stability.

- Encourage carve-outs for low-income households in any community solar/solar garden installations proposed in the Town. One unfortunate outcome of today's government-backed incentives for Distributed Generation is that the people who are best suited to take advantage of those incentives are owners of larger single-family homes. Lower-income households can either not afford the upfront investments, or do not own the property where they live. Providers of community solar systems are increasingly working with local utilities and municipalities to find ways for lower-income households to take advantage of renewable energy incentives.

- Given the prevalent use of electric hot water heaters in Lyons, the Town may want to consider a program to take advantage of the energy storage and cost reduction potential offered by those hot water heaters. The program would entail offering incentives to customers to allow the Town to install a remotely-controlled switch on their hot water heaters. This switch would allow the Town to remotely turn off customers' electric water heaters for a short amount of time, perhaps 15 to 60 minutes per incident, in times when the Town's overall electricity loads are expected to peak. This would reduce the Town's peak load and potentially reduce the demand charges that would result from the higher peaks. The impact on customers would be small, since the heat in the water heaters will largely be retained across the period when the heating elements are intermittently turned off. Further analysis would be required to determine participation thresholds, incentive amounts, and other elements of the program's design.

- Another program possibility is similar to the one described above. In this program the switch would be installed on building thermostats and the storage vessel would be individual buildings. The "switch" could be configured to turn down participants' thermostats temporarily, as opposed to turning them off completely. As above, the felt impact of demand reduction on customers would be small, or negligible. Again, further analysis would be required to design the program so that it benefits both the customer and the utility.

- Opportunity lies in the substantial energy savings that may be achieved by replacing customers' incandescent and halogen light bulbs with more efficient LED bulbs. LED bulbs use 75% to 80% less energy than the incandescent bulbs they replace and they last up to 25 times longer. The Town may want to consider a program whereby customers receive rebates on bulb purchases, or product discounts, with the subsidy coming from a separate energy reduction fund established by the Town. The benefit to the Town, in this case, is reduction in lighting loads; more likely these will result in peak reductions in the mornings of winter, spring and fall months, and the evenings of winter months. Some analysis will be required to compare program costs with the benefits of load reduction.

- Seek opportunities to develop local renewable generation with capacity value. Specifically, the Town may have opportunities to develop in-conduit hydropower generation[35], jointly with Longmont and/or MEAN, at Apple-Valley and Button-Rock Reservoir. It is unlikely that a small or micro hydropower plant can compete against the cost of energy from MEAN or WAPA, but the benefit may come from reduction in peak loads and corresponding capacity payments under MEAN's Capacity Commitment Compensation.

- Seek opportunities for energy storage coupled with variable generation, thereby adding capacity value to the variable sources.

- Leverage the energy storage opportunity at the waste water treatment plant.

- Leverage the Town's topology to facilitate pumped storage.

- Consider creating a fund to be used in support of clean-energy initiatives, such as NEM policies or credits for energy efficiency investments. The City of Boulder, for instance, has voted to impose a Climate Action Plan tax on every kilowatthour consumed by its residents. It is not exactly a carbon tax, but serves much the same purpose.

F. Additional Recommendations

1. Debt Service Early Repayment

The Town is presently repaying two 20-year debts: a 2003 non-taxable bond at 4.76 percent, and a 2006 taxable loan at 5.40 percent. Assuming no early repayment penalties exist in the terms of these debt obligations, the Town could repay its debt one year ahead of schedule by using its Debt Service Reserve to make the last principal and interest payment. For the 2003 Non-Taxable Bond, this would reduce the 2022 payment from $110,644 to $11,000 and save $5,775 in interest. For the 2006 Taxable Bond, the 2025 payment would be reduced from $41,492 to $10,100 and the interest saving would be $2,100.

The Town may consider a strategy to become completely debt-free in January 2023 by paying early the $112,153 balance for the taxable bond and the $110,000 balance for the non-taxable bond. The total $222,153 would be met by the aggregate $131,162 in Debt Service Reserve and a payment of $91,000; interest savings would amount to $18,000.

Table 16 shows the schedule for early repayment of both debts.

[35] Per CFR 18 4-90, in-conduit hydropower generation may be exempt from FERC licensing and dam safety regulations.

Table 16: Early Debt Repayment Schedule

January of:	2019	2020	2021	2022	2023	2024
Debt Service Reserve ($000s)	$ 131	$ 131	$ 131	$ 131	$ 131	$ 31
P&I Balance (BOY) ($000s)	$ 737	$ 618	$ 493	$ 361	$ 222	$ 77
Add'l Payment ($000s)	$ 605	$ 487	$ 362	$ 230	$ 91	$ 45
Interest savings ($000s)	$ (135)	$ (96)	$ (63)	$ (37)	$ (18)	$ (6)

2. Distribution feeders sub-metering

By installing non-revenue grade sub-meters on the distribution feeders, the utility would be able to:

- Improve preventive maintenance, by monitoring distribution transformers more closely.
- Better understand aggregated retail load behavior by geographic sectors.
- Better understand power flows, which will become increasingly important as new Distributed Generation serves a growing portion of the Town's load.
- Lay groundwork to perform daily and long-term load forecasting.

3. Multiple points of interconnection

The Town is entirely served by the Daugherty substation via a 5.5-mile-long single primary circuit. Although the substation and the Town feeder were isolated from the flood's impact, EPSIM recommends one or more of the following:

- Build a redundant circuit in a loop configuration between the substation and the Town.
- Build a substation on the west side of Lyons, fed by a back-up generator such as a local hydropower plant or gas turbine.

VIII. CONCLUSION

EPSIM Corporation has completed the enclosed Cost of Services Study for the electric utility owned by the Town of Lyons, based on data and documents provided by the Town, the Western Area Power Administration's Rocky Mountain Region (WAPA-RMR), and the Municipal Energy Agency of Nebraska (MEAN). The study entails a ten-year historical review of the utility's operations and finances, a ten year forecast of cost of services, and a set of recommendations.

The Town's utility has been tried by three consecutive events: revenue under-collection and load loss in 2012, the flood of 2013, and 2014 market regulation changes in the Southwest Power Pool Regional Transmission Organization. Despite the series of financial, physical and regulatory storms, the Town's utility has shown endurance and prompt recovery, thanks to the quality of its operations management and to strategic alliances with WAPA-RMR, MEAN and the City of Longmont. Projections for 2016 indicate that the electric utility has fully recovered and is back on a path to healthy growth and rate control. The electric utility appears sustainable.

Nevertheless, EPSIM would like to make the following recommendations which do not require any capital expense:

- Increase 2017 Revenues by 6.96 percent over 2016 revenues.
- Set separate accounts for the utility's restricted funds and for operating reserves.
- Review and update, on a quarterly basis, all costs, revenues, loads, and cash flow, reconciling each against budget.
- Reconsider Distributed Generation policies, particularly as it pertains to installed capacity allowance and Net-Metering rates.
- Bill the Town for electricity used by Town-owned properties.
- Include an annual Capital Improvement budget in the utility's fiscal plans.
- Start considering the impact of Electric Vehicles on the distribution assets capacity, on the Town's peak demand and on the cost/revenue forecast.

A second set of recommendations would require some capital investment:

- Access the meter data at the Daugherty substation to analyze demand peaks, shadow-calculate wholesale invoices, and track distribution losses.
- Replace the existing retail meters with interval meters.

The above recommendations should be considered by the Town as part of its 2017 operations objectives. Additional suggestions are included in the body of the report above.

Appendix A: Financial Model Documentation and Assumptions

I. Data Sources

From Town of Lyons:

PDF file “Lyons Electric General Ledger Sheets 2013 to July 2016.pdf”, received on 9/2/2016. Additional data for January 2008 to December 2012 included in PDF file “General Ledger Electric Lyons.pdf”, received on 10/21/2016.

Provides monthly financial results for Lyons Electric utility for January 2008 through September 2016.

Provides revenue by customer category and breakdown of expenses for three categories (allocated, administration, and maintenance), plus capital outlays.

Provides annual depreciation charges at aggregated utility level.

PDF files of Audited Financials for 2008 through 2014.

Provides Independent Auditor’s total financial results for Town of Lyons government and high-level Revenues, Expenditures, and Changes in Fund Balances for the Electric Fund.

PDF file “Asset Depreciation Report – Electric.pdf”, received on 10/21/2016.

Provides a listing of all capital assets and information on operational date, purchase price, expected life, and salvage value of 43 individual assets. Also known as the “Asset Keeper” report.

PDF file “Revenue Bond.pdf”, received on 10/21/2016.

Provides details on the “Debt Service Schedule” associated with the $1.48 million Revenue Bond issued in 2003 for the purchase of the Daugherty substation.

PDF file “Questions from EPSIM Sept19 2016 – Issued Oct21 2016.pdf”, received on 10/21/2016.

Answers to questions posed earlier to Town personnel by EPSIM staff.

II. Data Analysis: 2008 to 2016

The reported financials were transferred to the EPSIM Financial Model, preserving the four outlay categories

- Allocated expenses. These were detailed in the reports for 2011 through 2013, but then aggregated for 2008 through 2010 and 2014 through 2016. The account identifiers were preserved, and then grouped with other Administration expenses below.

- Administration expenses. Detailed accounts followed those itemized in the reports.
- Maintenance expense. Detailed accounts followed those itemized in the reports.
- Capital purchases. There is only one account for these outlays.

End-of-year adjustments in the December 2013-2015 General Ledgers were added to or subtracted from actual December amounts. This has a minor impact on monthly averages, but in general the adjustments are not large enough to significantly impact those averages.

In some instances, allocations in the "02-44-8002 - EF's Share Alloc Exp's from GF" account appeared as large entries in June or December of some years, with zero values in the previous five or eleven months. In such instances, the amount was averaged and spread over the previous periods to reflect the determination that the entries were "lumpy" posting of expenses that were naturally occurring regularly every month.

Also, historical monthly income/revenue accounts were transferred from the General Ledger reports to the EPSIM Financial Model, to allow comparison with modeled results later in our process. In some cases, differences were noted between the year-end totals as presented in the General Ledger sheets and the totals presented in the Audited Financial Statements. Where available, the General Ledger totals were used (2008 through September 2016). When any differences were seen they were noted, then with defaults made to the General Ledger amounts.

For 2008 through 2016 revenues, administrative expenses, and distribution/maintenance expenses used the monthly amounts reported in the General Ledger reports.

Representative monthly averages for each account were calculated based on General Ledger amounts reported for 2008 through September 2016. These form the basis for future forecasted expenses. Operating expenses are then forecasted into future years as if they occur evenly across each month of the year (no seasonal patterns).

Historical capital expenditures and asset levels were based on the "Asset Keeper" report of capital assets, using the detailed amounts for initial purchase price, operational start date, estimated useful life, and salvage value, to derive asset depreciation amounts over both historical and forecasted periods, using straight-line depreciation methods.

The 2003 Revenue Bond ($1,480,000, 20 years, 4.76%) was modeled as a non-taxable bond with fixed semi-annual interest payments and annual principal payments as outlined in the Debt Service Schedule. The 2006 Revenue Note ($412,000, 20 years, 5.4%) was modeled as a taxable bond with twenty equal annual payments of interest plus principal, based on a standard loan amortization schedule.

Forecasted revenues and expenses begin with October 2016. Forecasted monthly expense amounts are based on the monthly averages calculated above, adjusted for inflation, which are then forecasted to increase at the annual rate of inflation as specified in the initial model parameters.

The EPSIM Financial Model requires that some model parameters be specified by the model builder. These can be changed by users of the EPSIM Financial Model. Initial values used for the analysis in this report are as follows:

Parameter	Comments	Initial Value
Report Start Year		2004
Annual inflation rate	Drives increases in forecasted administrative and operating expenses	2.5%
Target Debt Service Coverage Ratio (DSCR)		1.25
Target Revenue Margin	Amount by which revenue forecast will exceed total outlay forecast	$50,000
Public Purpose Program (P^3) Fund	Modeled as percent of operating expenses to accrue to fund	0%
Payment in Lieu of Taxes (PILOT) Fee	Modeled as percent of operating expenses to pay to Town	0%
Working Capital	???	???
Liquid Funds Balance End 2008	Starting point for cumulative funds - to match 2008 Audited Financial Statements	$449,516

The Financial Model builds forecasted financial metrics in several sequential steps:

1. Estimate electrical loads, as hourly maximum and total kilowatthours per month per customer class
2. Estimate power costs based on MEAN/WAPA billing rates, as applied to estimated electrical loads
3. Estimate transmission costs based on WAPA OATT rates, as applied to estimated electrical loads
4. Estimate General Administrative expenses, based on historical averages and specified inflation rates
5. Estimate Distribution/Maintenance expenses, based on historical averages and specified inflation rates
6. Estimate Debt Service payments, based on the payment schedules for each debt instrument
7. Estimate collected revenues, based on the amount required to cover all cash expenses plus the Target Revenue Margin.
8. Calculate the Debt Service Coverage Ratio (DSCR) that results from Step 7 above.
9. Derive Required Revenue as the higher of the following two amounts:
    a. Estimated Collected Revenues from Step 7 above – amount required to cover costs
    b. Minimum Revenue required to produce a DSCR greater than or equal to the Target DSCR as specified in the model parameters.
10. Calculate the blended rate (required revenue per kilowatthour) based on the Required Revenue from Step 9 and the number of kilowatthours from Step 1.

Appendix B: Load Model Documentation

III. Data Sources

From WAPA:

Excel file "Lyons_DGS1201J11_2007 to 2016.xls", received on 9/7/2016

Provides hourly real and reactive energy since the installation of the new meter at the Daugherty Substation.

Readings span 12/13/2007 (HE 1) to 8/31/16 (HE 24). Actual readings start 12/17/2007 at HE 13.

This file is used to define the total energy consumption hourly

From Fort Collins Utility and Xcel's ERP: Hourly residential load profile

From Town of Lyons:

Excel file "MEAN Billing History thru May2016.xls", received on 9/2/2016

Provides breakdown of energy by sector (residential, commercial and Town-owned) for 2006 – 2009.

Provides breakdown of MEAN and WAPA energy supply by month between January 2007 and July 2016.

Provides historical monthly energy from MEAN invoices between 1994 and 2007

IV. Data Analysis: 2008 to 2016

With little hourly data available for 2007, we started the analysis as of 1/1/2008 and ran it through 8/31/2016. For each year, the process is:

- For each hour, separating the Dougherty meter reading between On-Peak and Off-Peak, according to WECC East wholesale tariff.
- Apply the *proxy residential hourly profile* by day of week and week of year against the Daugherty meter reading. Determine the maximum residential demand by matching the resulting annual energies in 2008 and 2009 against the breakdown provided by Lyons.
- *Assume the commercial and Town-owned loads follow a similar hourly pattern* as a first approximation.
- Determine the maximum commercial demand by matching the resulting annual energies in 2008 and 2009 against the breakdown provided by Lyons.
- Deduct the remaining load as being the Town-owned and street lights, compare to the 2008 and 2009 breakdown.
- Based on sunrise/sunset hours each day of the year, determine the street lights schedule and subtract it to further refine the Town-owned load.

The 2008 Town-owned annual energy is somewhat higher than indicated in the breakdown (219 MWh versus 144.8 MWh); however, if we take into account the difference between the Total Consumption and the (Wholesale Purchase minus line loss), the Town-owned energy difference is much smaller, about 18 MWh or a 12.5 percent uncertainty on the Town-owned load. The error could include unaccounted-for street lights but this induces another error in the net Town-owned load.

The year 2009 shows a decrease in residential maximum demand to 1.53 MW and, likewise, a commercial decrease to 0.87 MW. The Town-owned energy with street lights is 859 MWh, which matches the breakdown if we take into account the difference between the Total Consumption and the (Wholesale Purchase minus line loss).

Years 2010 through 2016 do not have a historical breakdown by sector. The maximum demand by sector is estimated by breakdown of the annual energy:

- Residential: 60 to 63 percent of total annual energy
- Commercial: 33 to 35 percent
- Town-owned and unaccounted-for: 3 to 7 percent

V. Data Analysis: 2016 to 2026

The data forecasting beyond August 2016 hinges around the annual load growth by sector. The period 2014 through August 2016 outlines the post-flood recovery trends for residential and commercial.

The year 2016 is derived by comparing the load growth, in aggregate from January through August, between 2015 and 2016 and extrapolating the growth for September through December.

Years 2017 through 2026 require user input for the annual load growth of residential and commercial sectors. The Town load is derived as following half the overall growth from the prior year. The forecasted total energy at the substation is determined for each forward year as the sum of the three sectors. In parallel, forecasted monthly load is calculated by customer group as the prior year's month load times the year's annual growth. On-Peak and off-peak energy is calculated from the month's forecasted load and the historical average (2008 – 2016) share of peak or off-peak energy.

On peak and off peak demands are forecasted at the monthly level from the month's load forecast and the historical average (2008 to 2016) load factor for that month.

VI. MEAN Power and Energy Supply

Following changes in Tariff dated January 29, 2004, effective April 1, 2004:

- Section 4.03: Customer Charge changed from $2,200 to $0 per month

Following changes in Tariff dated January 26, 2006, effective April 1, 2006:

- Section 4.05: Power Factor requirement raised from 90% to 95%
- Section 3.01: Total Metered Energy adjusted for Transmission Losses
- Section 3.01: Added Supplemental Agreement for Wind Generation
- Section 3.05: Definition of City's Monthly WAPA Energy

Following changes in Tariff dated August 15, 2013, effective April 1, 2013:

- Section 6: Capacity Commitment Compensation

Following changes in Tariff dated November 20, 2014, effective February 1, 2015:

- Section 4.03: Added Customer Charges
- Section 5.02: Added Support Energy rate

Following changes in Tariff dated January 22, 2015, effective April 1, 2015:

- Section 3.01: Added Fixed Cost Recovery Charge
- Removed Demand Charges (Base and Incremental)
- Removed Base and Incremental Energy
- Removed Minimum Billing Energy
- Removed SUMMER / WINTER season rates
- Section 3.02: Single charge rate for Supplemental Energy

VII. Customer Load Profiling

EPSIM applied proxy hourly profiles for residential and secondary commercial customer classes. These profiles were compiled and derived from nearby utilities including Public Service Company of Colorado (2011 Electric Resource Plan) and Fort Collins Utility. The hourly proxies assume a consistent customer behavior in the aggregate, year after year; this is more valid for residential than commercial loads.

The proxy coefficients used in the model are hourly percentages of the annual load, applied by hour of day, day of week and week of year. A customer group will have a different behavior on a Wednesday in January than a Sunday in July. The hourly demand derived from these calculations is applied to the native loads, before solar Distributed Generation. A proxy hourly solar profile is applied to derive the customer group's metered – or net – load. There is a limitation to the validity of these proxies and the results are speculative and for information only. The results by customer class could be further refined if the Town could provide monthly energy totals rather than annual totals.

VIII. Weather Normalization of Load

Customers may use appliances differently under various weather conditions. Examples include HVAC units and water heaters. A possible enhancement to the Financial and Load model would be to track monthly Heating and Cooling Degree Days. Dividing a customer group's monthly energy by the applicable heating and cooling degree days will provide a weather-normalized load. The baseline, derived from historical data, can be used for projections and comparative studies. Weather normalization will facilitate alternative scenario analysis such as mild summer load, cold December load etc. It will also allow the Town to review trends in customer classes, such as the development of homes with air conditioning units or electric heat. Lastly, it will allow the Town to compare a single customer against the average and possibly make recommendations on energy efficiency.

Appendix C: Glossary and Acronyms

IX. Glossary

"Active Energy" (also "real energy") means the amount of electrical energy that is actually delivered to the load in an alternating current (AC) system, given the phase differences between voltage and current at any given time. From Wikipedia (https://en.wikipedia.org/wiki/AC_power) – "power in an electric circuit is the rate of flow of energy past a given point of the circuit. In alternating current circuits, energy storage elements such as inductors and capacitors may result in periodic reversals of the direction of energy flow. The portion of power that, averaged over a complete cycle of the AC waveform, results in net transfer of energy in one direction is known as **active power** (sometimes also called real power). The portion of power due to stored energy, which returns to the source in each cycle, is known as **reactive power**."

"Apparent Energy" means the simple product of voltage and current in an alternating current (AC) system, without regard for the presence of reactive energy due to the phase differences between voltage and current at any given time. Apparent energy = Active energy + Reactive energy.

"Billing Period" means the period between two successive meter readings taken for the purpose of billing.

"Capacitive" means a condition in an AC electrical system whereby the current leads the voltage in phase

"Capacity" means the maximum electric output experienced within an electrical system in specific conditions.

"Demand" means the number of kilowatts (kW) which is equal to the number of kilowatt-hours (kWh) delivered at any point during any clock-hour.

"Distribution" means

1) the electrical system at the end of a one-way flow of electricity from generator, through transmission, and through distribution to individual consumers, also
2) all power lines and energy distribution facilities rated below 35kV, or
3) in the Town of Lyons' case, all wires, poles, transformers, meters, and other devices served by the Daugherty substation.

"Drought Adder" means the component within the WAPA rate schedule intended to cover additional costs related to drought condition in the western U.S.
"Energy" means an amount of electricity produced or delivered over a specific period of time.

"Firm Power Requirement" means the maximum clock hour integrated system demand of the City occurring during the current Billing Period, or the 11 preceding months.

“Fully Subscribed” means a condition whereby all power and energy that can be committed and under contract is committed and under contract. That is, no additional power/energy is available for sale.

“Inductive” means a condition in an AC electrical system whereby the current lags the voltage in phase.

“Power Factor” means the ratio of active power to apparent power in an electrical circuit. The higher the power factor the less energy that is lost to AC energy storage elements. Low power factor is caused by inductive loads such as transformers, induction motors, generators and certain lighting ballasts. See (http://www.coned.com/reactivepower/the_cause_of_low_power_factor.pdf)

“Proxy Curve” means a set of data points that define a shape, or profile, of a known quantity, at a given level. A “proxy curve” can then be used to approximate the characteristics of similarly behaving entities at other levels. Essentially, the proxy curve preserves relative values while allowing modification of absolute values

“Reactive Energy” – see “Active Energy” above

“Requirements Purchaser” means a Purchaser that is purchasing its load requirements, including load growth, from MEAN, pursuant to the MEAN contract.

“Subtransmission” means all transmission lines and substation facilities rated at 69 kilovolts (kV) and below.

“Total Requirements Service” means service to a Requirements Purchaser.

“Transmission” means all transmission lines and substation facilities rated above 69 kilovolts (kV).

X. ACRONYMS

CNS:	Cooper Nuclear Station
CROD:	Contract Rate of Delivery
DG:	Distributed Generation
DLF:	Distribution Loss Factor
DSCR:	Debt Service Coverage Ratio
DSR:	Debt Service Reserve
EVSE:	Electric Vehicle Supply Equipment
FERC:	Federal Energy Regulatory Commission
GGS:	NPPD Gerald Gentleman Station
ISO:	Independent System Operator
kVA:	kilo-Volt-Ampere, a unit of apparent power
kVAR:	kilo-Volt-Amps-Reactive, a unit of reactive power
kVARh:	kilo-Volt-Amps-Reactive-hours
kW:	kilowatts
kWh:	kilowatt-hours
kW-Mo	kilowatt-month (maximum kW in a month)
LAP:	Loveland Area Projects
LF:	Load Factor
LGS:	Louisa Generating Station
MEAN:	Municipal Energy Agency of Nebraska
MCP:	Market Clearing Price

MW:	megawatts
MWH:	megawatt-hours
NEM:	Net Energy Metering
NITS:	Network Integrated Transmission Service
NMPP:	Nebraska Municipal Power Pool
NPPD:	Nebraska Public Power District
OATT:	Open Access Transmission Tariff
PILOT:	Payment in Lieu of Taxes
PF:	power factor
PPA:	Power Purchase Agreement
PPGA:	Public Power Generation Agency
PV:	Photovoltaic (solar electric)
RES:	State Renewable Energy Standard
RTO:	Regional Transmission Operator
SPP:	Southwest Power Pool
WAPA:	Western Area Power Administration
WAPA-RMR:	Western Area Power Administration Rocky Mountain Region
WAPA-RMR TSA:	WAPA Transmission Contract 08-RMR-1811
WEC1:	Hastings Whelan Energy Center Unit 1
WEC2:	Whalen Energy Center Unit 2
WECC:	Western Electric Coordinating Council
WREGIS:	Western Renewable Energy Generation Information System
WSEC4:	Walter Scott Energy Center 4
YOY:	year-over-year