

1. Power Commission Meeting Materials

Documents:

[PACKET.PDF](#)
[AGENDA.PDF](#)
[UTILITY RATE MAKING CONCEPTS.PDF](#)
[KAYSVILLE CITY ELECTRIC RATE STUDY RESULTS.PDF](#)

2. Meeting Audio & Video

- [MEETING AUDIO](#)
- [MEETING VIDEO](#)



MEETING NOTICE AND AGENDA

Notice is hereby given that the Kaysville City Power Commission will hold a regular meeting on Tuesday, March 7, 2017 starting at 7:00 p.m. in the Council Room of the Kaysville City Municipal Center, 23 East Center Street, Kaysville, UT.

The agenda shall be as follows:

1. Opening Ceremonies.
2. Approval of Minutes.
3. Conference Call with Mark Beauchamp UFS
4. Solar Discussion
5. Rate Study Discussion
6. Mission Statement
7. Other Discussion Items for Upcoming Meetings
8. Call to the Public
9. Adjournment

Kaysville City is dedicated to a policy of non-discrimination in admission to, access to, or operations of its programs, services or activities. If you need special assistance due to a disability, please contact the Kaysville City Offices at (801) 546-1235.

I hereby certify that I posted a copy of the foregoing Notice and Agenda at City Hall and emailed copies to media representatives on March 1, 2017.

Stacie Harward

Stacie Harward
Administrative Assistant
Kaysville City Power Department



**2012
INTEGRATED
RESOURCE PLAN**



2012 INTEGRATED RESOURCE PLAN

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2012 INTEGRATED RESOURCE PLAN

EXECUTIVE SUMMARY

Utah Associated Municipal Power Systems (“UAMPS”), on behalf of its members¹ submits this Integrated Resource Plan (“IRP”) as required by Section 114 of the Energy Policy Act of 1992, Public Law 102-486, subject to completion of the Energy Planning and Management Program in October 1995, 60 FR 54151 (October 20, 1995) and as revised in 65 FR 16789 (March 30, 2000) by the Western Area Power Administration (“WAPA”). This IRP provides guidance to UAMPS’ members in meeting their objective of providing a reliable, least-cost, electrical energy supply portfolio for the next five to ten years. This IRP balances competition, rate structure, environmental effects, reliability, technical evaluation, public input, as to demand and supply-side alternatives. UAMPS submits this IRP in a time of rapidly evolving power supply markets and a volatile regulatory environment. Considering these conditions, UAMPS has assumed, for the purpose of this IRP that public sentiment and regulations will lean toward an emphasis in renewable generation, greenhouse gas (GHG) emission mitigation, demand-side management, efficiency practices and clean supply-side alternatives.

Since its inception in 1980, UAMPS has used integrated resource planning to maintain competitive rates and reliable service. Resource planning is a continuous and dynamic process which can not be frozen in time. Given these dynamics, this IRP only represents conditions as of this date. Many of the issues and assumptions presented will change as members’ needs and available resource options evolve.

Resource objectives for UAMPS include minimizing impacts on rates to members and portfolio integration costs, maintaining system reliability, ensuring flexibility while short-term and long-term needs are met with diversity in resource mix. These objectives will be influenced by several key issues such as Federal and State legislation and policy which will include GHG emissions. Other key issues include regional transmission infrastructure, load growth and the increasing cost of resource development.

In order to maximize efficiency of resource management, UAMPS gathers hourly data for each of its members and analyzes the data in a computer model that provides analysis of key factors. The resulting load forecasts are provided to each member for their review and confirmation. UAMPS aggregates member forecasts to provide a diversified system forecast.

Because UAMPS is not an all-power requirements supplier to its members, UAMPS depends upon the member’s load/resource portfolios to meet load requirements. The diversity of the UAMPS

¹Listed in Exhibit A

membership ranges from winter and summer peakers to those with long resource positions and those that are short resources. UAMPS utilizes surplus member resources to meet deficit member's loads, which are not sufficient to meet all members load. UAMPS meets resource deficits with appropriate supply-side and demand side resources through its projects.

Because of today's evolving power supply markets and a volatile regulatory environment, traditional approaches to power supply are inadequate. Therefore, UAMPS has adopted a demand-side approach to capture efficiencies in both load requirements and resource management. The approach begins with programs aimed at encouraging residential customers to use energy more efficiently by offering cash incentives. Additionally, UAMPS continues to search for cost effective avenues to provide efficiency programs to address the needs of commercial and industrial customers. UAMPS will aggregate these solutions to provide an economy of scale in the implementation. The end result from more efficient energy consumption will be lower energy cost and reduced GHG emissions.

UAMPS recognizes that the demand-side approach will not fully meet members' long-term resource needs. However, in its analysis of supply-side resources, an emphasis will be placed on renewable resources.

SECTION 1 – INTRODUCTION

UAMPS, through its CRSP and Resource Projects, has been charged to address resource planning for the joint benefit of its members. The planning horizon for this IRP is ten years with a focus on the first five years. It is expected that the near-term resource integration issues will impact long-term options. Uncertainty with the development of current UAMPS projects, as well as the uncertainty of future regulations complicates resource planning. However, these uncertainties necessitate thorough planning that estimates the effect of various internal and external factors.

This submittal represents a continuation of UAMPS' ongoing IRP process. This is a public document, available for review at each member's place of business.

1.1 Background on UAMPS Members

UAMPS members' electric systems, for the most part, were established in the first half of the last century. Pursuant to state law each member has the authority to generate, distribute and sell electric power within its geo-political boundaries. Information on each member's system is listed in Exhibit B.

Pursuant to UAMPS organizational agreements UAMPS has undertaken projects on behalf of its members, consistent with its purposes as set forth in its organization agreements. These projects are: 1) Colorado River Storage Project (CRSP), 2) Firm Power Supply, 3) Pool, 4) Craig-Mona, 5) Central-St. George; 6) Hunter, 7) San Juan, 8) Intermountain Power (IPP), 9) Payson (Nebo), 10) Resource, 11) Member Services, 12) Government and Public Affairs, 13) Horse Butte Wind, 14) Natural Gas, and 15) Freedom Project.

Since its creation, UAMPS has sought to develop new electric power supplies for its members through the acquisition of interests in electric generating facilities, demand-side

programs, wholesale market power purchases, and development of transmission access to power supply markets in adjacent states. Through a diversity of power supply resources and a diversity of load, UAMPS and its members are able to benefit from the least cost sources of power. This decreases reliance on any single source of electric power while stabilizing load profiles and increasing the capacity factor of the system.

UAMPS sells the capacity or service provided by each of its projects under contractual agreements with its members. Not all of the members participate in every project that has been undertaken. To the extent that UAMPS has issued bonds to finance the capital costs of a project (i.e. the Central-St. George; Craig-Mona (retired); Hunter (retired), Payson and San Juan), such bonds constitute special obligations of UAMPS and are secured solely by payments made to UAMPS by those members participating in the financing of the project.

The members serve residential, commercial, small industrial and several large industrial customers. The governing body of each member regulates electric service and rates to its customers. Rates of the members generally are comparable to the rates of neighboring utilities. The members maintain rates for electric service, sufficient to provide operating revenues, which include operating and maintenance expenses, debt service, renewals and replacements and distribution expansions.

1.2 **Resource Planning Objectives**

UAMPS' fundamental goal is to provide a reliable, cost-effective, electric power supply portfolio to its members. Objectives of this IRP, based on this goal, are:

- Minimize impacts on rates to members
- Minimize portfolio integration costs
- Maintain system reliability
- Ensure flexibility
- Ensure short-term and long-term needs are met
- Maintain diversity in resource mix

UAMPS will have to balance all these objectives to reach our goal. Demand side and supply side options, in various combinations, will compete for selection into UAMPS' resource portfolio. In order to evaluate resources to be included in UAMPS' portfolio the following selection criteria will be used.

1.2.1. **Financial**

The analysis of the impact on UAMPS' rates includes such factors as purchase costs, operating costs, financing costs, and other costs or revenues that may be unique to a specific resource.

1.2.2. **Operational**

All resources will be evaluated according to how well they meet UAMPS' and its members' load needs.

1.2.3. **Reliability**

Reliability is essentially a measure of how each resource meets its performance objective. For supply side resources, reliability measures the availability of the resource to operate. For demand side resources, reliability measures the reduction in demand over time.

1.2.4. **Environmental**

All resources must meet local, State and Federal environmental requirements. UAMPS expects environmental requirements to be the key factor in evaluating any project. Each resource will be judged and ranked according to their ability to meet environmental requirements.

1.2.5. **Flexibility**

Flexibility is a measure of how well a resource can adapt to changing requirements. For example, some supply side resources can be obtained only in discrete sizes so a purchase contract may be more appropriate to match exactly the needs of the requestor.

1.2.6. **Short-Term and Long-Term**

By its very nature, an electric utility has both short-term and long-term obligations to its customers. Both considerations are important when evaluating alternatives.

1.2.7. **Diversity**

Diversity in type and location of resources balances the risk during disruptive periods plus opens up additional market availability.

1.3 **Key IRP Issues**

In the process of developing this IRP several key and unique issues, both internal and external to UAMPS and its members, were considered. These issues, in no specific order, are:

1.3.1. Future regulatory uncertainty regarding GHG emissions.

1.3.2. The Energy Policy Act of 2005. The “Act” includes key requirements that will affect UAMPS and its members operations and planning. These provisions include sustainable resource development, specifically clean coal technologies, renewable energy and nuclear power. The Act encourages increased and efficient hydroelectric production and relicensing processes, the implementation of metering options including time of use and net metering and the establishment of mandatory reliability standards.

- 1.3.3. Additional load growth during the ten year planning period.
- 1.3.4. The existing regional transmission infrastructure.
- 1.3.5. The increasing revenue requirements needed to cover the costs of providing energy, including decommissioning costs associated with existing resources.
- 1.3.6. State and Federal laws and policies, including but not limited to, the Clean Air Act, the Clean Water Act, the Endangered Species Act, the marketing criteria of the Salt Lake Integrated Projects (SLIP), the Federal Power Act and the National Energy Policy Act.
- 1.3.7. UAMPS is a project-based, wholesale electric service entity. The members purchase cost-based wholesale electric services from UAMPS via project contracts. The members are solely responsible to meet their load requirements either through UAMPS or from any other source. Therefore, the UAMPS' IRP is based on members' input and aggregated in order to best optimize the utilization of all resources.
- 1.3.8. UAMPS, through its Resource Project, reviews all resource options available including demand side and renewable resources.

SECTION 2 - LOAD FORECASTING

2.1 Forecasting Process

UAMPS prepares its forecasts, through proprietary computer modeling, by analyzing the individual historical hourly meter readings of its members, adjusted and normalized for system outages, data outliers, other unexplainable data points and average weather temperatures and data sources. Individual member forecasts are aggregated into a UAMPS system load. UAMPS identifies growth trends from the historical data and validates them with known load events and other factors that would influence load profile or growth rate. Individual members are involved throughout the process so that their local knowledge and load assumptions are incorporated into the forecasting process. The computer model allows for sensitivity analysis by adjusting the data and other model inputs. Assumptions can be modified independently for energy usage and peak demand based on high load and low load energy needs and various other scenarios that may arise in the forecast period. The member's aggregated forecasts are presented to the members and the UAMPS Board of Directors for approval.

2.2. Data Sources

Data sets used for analysis and assumptions are obtained from a variety of sources. Historical hourly load data from group and individual meter points is obtained and maintained by UAMPS. Demographic information is provided by the State of Utah Office of

Planning and Budget, economic development agencies and local Chambers of Commerce. Long-term forecasts of economic data as well as price escalators are obtained from the Annual Economic Report to the Governor of Utah and various regional and national sources. Analysis of raw data, assumptions and data presentation is performed by UAMPS.

SECTION 3 - LOADS AND RESOURCES

3.1 Load and Resource Analysis

UAMPS' current resource portfolio includes: a long-term hydroelectric Power Purchase Agreement (PPA) with Western Area Power Administration (WAPA), two (2) long-term power purchase agreements from two different wind resources, a medium-term market purchase, partial ownership in two coal-fired power plants, total ownership of a combined-cycle, gas-fired power plant, and several short-term market-based power purchases. Also, UAMPS incorporates power purchases that some members procured outside of UAMPS. Additionally, members make available to UAMPS their power purchase agreements in Units 1 and 2 of the Intermountain Power Project (IPP). UAMPS members also make available their own diesel and gas-fired generating units, small hydroelectric projects, demand-side programs, renewable and other distributed generation resources. Each of these resources is forecasted into the future, based on the contractual terms and the scheduled or estimated availability of such resource. A cumulative stack of projected resources is then compared to the anticipated load and energy requirement for each UAMPS member for the forecasted period. Potential new resources are analyzed by the economic impact to member rates, the load needs of UAMPS' members, and how well they integrate into the existing resource portfolio.

3.2 Load Characteristics

UAMPS' load is an aggregated composite of all the individual members. The diversity of the group provides a composite load characteristic that is the sum of the members energy needs but is less than the sum of the members' peaks. This load profile is less volatile and more predictable than that of any one individual member.

Several of UAMPS' members faced exceptional high load growth during recent times of economic prosperity, most notably the members in Utah within Utah and Washington Counties. However, due to the recession following 2008, load growth has stalled in the last several years. UAMPS' weighted load growth, while somewhat tempered by the slower growth of some of the smaller, rural members, was once growing at a rate exceeding historical averages. Again, this has been slowed by economic factors and it is expected to fall to the lower or middle range of historical average. However, Utah and the West in general is somewhat insulated from severe economic shocks due to several factors, not limited to a young, highly educated workforce, more competitive wages, relatively low energy rates, lower regulatory and other operating costs, strong emigration from other states and generally, robust economic development in the high-tech, energy and manufacturing industries. Load growth is expected to increase in residential and commercial growth stemming from a relatively better economy, national and regional migration into members'

cities, building trends that incorporate large homes, central air conditioning and increasing home electronics and appliances purchases.

3.3 **Load and Resource Mix**

UAMPS identifies three categories of load and resource characteristics: base, intermediate and peaking. Obtaining the correct resource to serve each of these three characteristics provides a least-cost resource portfolio.

Base load is that amount of total load that is in demand 100% of the time. A base load resource is ideal to meet this characteristic.

A base load unit is designed to yield maximum operating efficiency at continuous operation for periods of 20 or more years. This optimization is normally accomplished by a considerable initial capital investment in order to yield lower relative operational expenses. Examples are hydroelectric facilities, coal and gas-fired generation, geothermal resources, wind and demand side programs.

Intermediate load is that portion of the load profile that is greater than base load up to the average peak. Intermediate load is generally present from the early morning to the late evening or approximately 50% of the time.

An intermediate load unit is designed to start up and shut down on a regular basis, generally daily or seasonally to operate between a minimum and maximum load while in operation to follow the load curve. Examples are combined cycle natural gas-fired generation, solar generation and demand side programs.

Peak load is that portion of the load profile this is greater than average peak amounts. Peak load is present in the early morning and the late evening for relatively short durations or approximately 20% or less of the time.

A peaking unit is designed to come on line and be shut down in a short time frame to accommodate short duration electric demand. Examples are natural gas combustion turbines, reciprocating engines fueled by natural gas, diesel or residual fuel oil, and demand side programs.

3.4 **Resource Needs of UAMPS**

UAMPS' resource availability to load requirement has been negative on average resulting in the need to rely on short-term power purchases. UAMPS has a forecasted future resource need, primarily due to member system growth and replacement of expiring long-term power supply contracts. Proposed criteria for screening demand and supply side alternatives were established in section 1.2 of this IRP.

UAMPS and its members are currently investigating a vast number of resource options under the umbrella of its Resource Project. These options vary widely, but are mostly renewable in nature and include small hydroelectric, wind generation, geothermal power, waste-heat capture technologies, solar energy, and include energy efficiency and demand side management programs. Larger, base to intermediate resources are almost exclusively gas-fired technologies. Political uncertainty, carbon legislation and aggressive regulatory mandates have made new coal generation difficult to consider. There is a desire to investigate new, small nuclear technologies; however, more political certainty would be beneficial. UAMPS will consider all power resources, provided they meet established criteria; generally being safe, low-cost, and reliable in nature.

SECTION 4 - RESOURCE ASSESSMENT

The following sections describe current resource positions as well as potential resource possibilities.

4.1 **Member Owned Resources**

In the near-term UAMPS is nominally surplus base-load capacity from IPP Units 1 and 2. UAMPS administers these member's Power Sales Contracts and exercises certain rights and provisions available through the Excess Power Sales Agreement. Under the agreement available surplus is sold to four (4) California cities with specific provisions to "call back" capacity to serve members load for both short-term and long-term periods. UAMPS intends to exercise these rights to this surplus power to meet the growth of its members.

Independent of UAMPS, some of its members proactively pursue the development of their own resources and projects. The primary purpose of generation projects internal to a UAMPS' members system is reliability, and not necessarily economic cost. Peak load needs in the summer, voltage support, transmission system requirements and other reliability needs specific to the area are some of the needs that member-owned generation can help meet. Member-owned generation is directly interconnected to the member-owned distributions system and can meet the reliability needs for their own system or for their customers such as hospitals, government facilities or certain industries that need the assurance of reliable electric power. Member-owned generation is typically small hydro between 100 kW and 2,000 kW and small thermal facilities that include gas and diesel reciprocating engines and small gas turbines between 650 kW and 13,500 kW.

Several UAMPS members have evaluated larger gas projects to meet needs specific to their individual system. Specifically, UAMPS members in the Washington County load pocket have installed gas-fired generation to meet the load growth rate. Also, given their relative location in Southwest Utah, they have load factors and load profiles that are extremely “peaky” due to the heavy use of air conditioning in the summertime.

Small renewable projects, such as small hydro, solar and especially landfill gas, are typically tied to resources locally available to a specific member. Many UAMPS members have several of these resources, not limited to small rivers, local landfills, specific canyon winds or solar sources. Projects associated with these resource options are generally financed and developed at the member’s local level.

4.2 **Long-Term Power Purchase Contracts**

UAMPS receives two seasonal allocations of hydroelectric capacity and associated energy from WAPA. Through the Firm Power Supply Project UAMPS provides long-term market purchases and other PPAs, most notably a wind-powered PPA.

Through the recently developed Horse Butte Wind Project, UAMPS solely managed the construction and has entered into a long-term PPA for 100% of the output.

UAMPS has several power purchase contracts. In the short-term, there is competitively priced power available for purchase with various terms and structures. Suppliers are eager to enter into market sales for these various terms and structures. Market conditions, given the state of the economy on loads and load growth, along with the supply of relatively cheap natural gas, generally support market buyers.

4.3 **UAMPS Ownership**

UAMPS has ownership in the coal-fired Hunter and San Juan projects and the gas-fired Payson Project power plant.

4.4 **Natural Gas Generation**

The Payson Project in Payson, Utah, a gas-fired combustion turbine with a duct-fired heat recovery steam generator (“HRSG”) and a dual-pressure steam turbine, to provide a nominal combined cycle generating capacity of 140.5 MW was completed and operating commercially as of May of 2004. The gas turbines and duct burners are fueled solely by natural gas. It is designed to be operated as either a base load, intermediate or peaking unit although the economics change for each configuration.

Because of the rapid growth by this project’s participants and evolving ownership structure, and the economics of the power market, the Payson Project is operating closer to intermediate/base load plant, running most of the time during the daytime hours.

As a significant source of clean and reliable power, UAMPS will continue to investigate the use of natural gas-fired power as a potential resource to meet its future needs.

4.5 **Coal Generation**

UAMPS has ownership interests in two coal-fired power plants, Hunter #2 and San Juan #4. Also, twenty-three UAMPS members have power purchase agreements in Units 1 and 2 of the IPP Project of which UAMPS administers on their behalf. The development of the third unit mentioned in the prior IRP submittal was abandoned during the last IRP period.

UAMPS will continue to investigate the latest, most acceptable “clean coal” technologies that will benefit its members by means of reliability and low cost, provided there is economic and regulatory certainty associated with those technologies.

4.6 **Wind Energy**

As a result of the last IRP process, UAMPS has investigated and acquired a second wind resource through a PPA with the Horse Butte Wind Project. UAMPS solely developed the project wind generation facilities. Due to the nature of the financing of the Project, UAMPS sold the asset to a partner and then entered into a PPA for the total output of the project. Provided the project meets or exceeds certain operational and economic parameters, UAMPS will have the option to purchase the project in 5 years with additional economic benefits to its members.

UAMPS also has a long-term PPA with Iberdrola Renewables for about 10% of the output of the Pleasant Valley Wind Plant located near Evanston, Wyoming.

Wind has an important role in power generation and UAMPS is working to integrate wind resources with operational and cost attributes that compliment UAMPS' resource mix.

4.7 **Geothermal**

UAMPS investigates proposed geothermal resources when offered by developers. While the relative cost is still the most likely barrier to development, it is a resource option that several members have shown a preference in pursuing.

4.8 **Demand Side Programs**

Demand side programs are an important part of UAMPS' resource mix. While these programs cannot fulfill the entire long-term need of an additional resource, successful implementation of these programs can often times be sufficient to meet short-term load growth and some peaking needs. UAMPS launched three demand side programs aimed at residential customers in June 2009. The Home Energy Savings Program offers incentives for

Energy Star appliances. The Cool Cash Program aims to reduce summer peak load by offering customers incentives for high efficiency central air conditioning equipment and evaporative coolers. The See Ya Later, Refrigerator Program pays customers incentives for recycling refrigerators and freezers. Demand side programs are described in more detail in Section 5.

4.9 **Other Considerations for New Resources or Purchases**

4.9.1 **Transmission**

If UAMPS were to acquire more resources, additional transmission capacity may be required across constrained transmission paths.

UAMPS has been participating in various forums in the Western interconnection region over the last ten years to develop a reliable transmission grid. Currently, UAMPS is participating as a founding member of the Northern Tier Transmission Group ("NTTG") with PacifiCorp, Idaho Power Company, Northwestern, Portland General Electric and Deseret Power. The purpose of NTTG is to administer regional transmission planning and construction with all stakeholders, including transmission owners, transmission customers, and State and Federal regulatory entities. UAMPS envisions that NTTG will provide a forum to incorporate all of the Load and Resource forecasts and plans within its footprint and neighboring regional planning organizations and develop a comprehensive, least cost transmission plan that satisfies to the extent possible all stakeholders needs. There already have been major transmission projects announced by NTTG which will have a major impact on the resource planning of UAMPS and others.

4.9.2 **Environmental**

UAMPS complies with all State and Federal regulations and statutes. UAMPS is taking into consideration the impact that possible new regulation of greenhouse gases in its analysis of new resource options.

SECTION 5 – DEMAND SIDE MANAGEMENT PROGRAMS

5.1 **Demand Side Management Overview**

With the increase of wholesale power prices, UAMPS sees an opportunity to reduce its exposure to the market through an effective Demand Side Management (DSM) program. DSM not only puts off the need to enter into supply side options, but it will add a number of environmental benefits including reduced air emissions, water usage and land use. Reducing energy consumption through efficiency and conservation will reserve and extend the life of limited energy resources and mitigate future costs associated with transmission and generation infrastructure.

UAMPS has long believed that DSM was best undertaken by its members however, evolving conditions in the energy markets and developing CO2 debate have cause UAMPS to propose a group based DSM program. To this end, UAMPS has made DSM a priority by exploring and encouraging all potential demand side programs.

In the past, each individual member of UAMPS has determined their individual demand side endeavors that best work for the size and scale of their individual system. Individual member programs are generally a function of the relative size and the distinct load characteristics that determine the effectiveness of different programs. The size and composition of the customer base or local weather patterns may make some demand side programs more effective than others.

UAMPS makes Demand Side Management Programs available to its members through its Resource Project. UAMPS feels that there is the ability to leverage the organizational structure and experience to help all members regardless of size implement and maximize DSM programs across the entire membership and make a measurable impact on aggregate loads.

5.2 **UAMPS Demand Side Activities**

UAMPS continues to work with its membership, environmental consultants, state agencies, and other stakeholders to define and implement the most effective DSM programs to its membership.

UAMPS developed comprehensive residential demand side programs modeled after Rocky Mountain Power's Home Energy Savings Program, Cool Cash, and "See Ya Later, Refrigerator" programs. Launched in June 2009, residential customers of participating UAMPS' member utilities are eligible to receive cash incentives and long-term energy and cost savings.

Home Energy Savings Program: Customers can receive incentives ranging from \$20 to \$75 by purchasing ENERGY STAR clothes washers, refrigerators, dishwashers, room air conditioners, lighting fixtures, and ceiling fans, as well as qualifying electric water heaters from participating retailers. The incentives will be available regardless of who installs the product.

Cool Cash: Cool Cash encourages installation of evaporative cooling systems, and/or the proper sizing and installation of high efficiency central air conditioning equipment. Customers who choose the evaporative cooling option can buy new or replacement evaporative coolers from any source they prefer but the equipment must meet specific efficiency standards. Customers may install the evaporative cooler themselves, and do not need to purchase professional installation services. Customer incentives for evaporative coolers range from \$100 to \$1,000 and dealer incentives range from \$25 to \$300. Customers who choose central air conditioning must purchase new, UAMPS-approved equipment. To qualify for the incentive, customers must also work with a participating vendor to ensure the unit(s) are sized and installed correctly. Customer incentives for central air conditioning systems range from \$50 to \$150 and dealer incentives range from \$25 to \$75.

See Ya Later Refrigerator: Older refrigerators use excessive amounts of energy, but hauling them off and properly disposing of them can be difficult. The “See Ya Later, Refrigerator” enables customers to schedule a pick-up of their working refrigerators or freezers. The old appliances are recycled and hazardous materials are disposed of properly and safely. Customers receive a \$30 cash incentive.

UAMPS has also established a collaborative relationship with the State Energy Program of the Office of Energy Development of the State of Utah for the purpose of implementing effective DSM program strategies for its members. The State Energy Office is targeting Federal dollars that are specifically allocated to the acquisition and implementation of DSM programs.

In April 2010, UAMPS received an award under the Energy Conservation Block Grant Program (EECBG), as part of the American Reinvestment and Recovery Act (ARRA), to replace standard High Intensity Discharge (HID) streetlights with Light Emitting Diode (LED) units in fourteen member communities. The project was awarded through the Utah Office of Energy Development and enabled UAMPS members to purchase 2,096 LED street light units. All UAMPS members in the Resource Project who did not receive EECBG Formula Grants were eligible and invited to participate. Additionally, participating UAMPS members pledged to reinvest the energy cost savings in additional LEDs for a period of three years.

The demand side activities currently administered by UAMPS are described in this section. "Exhibit C" of this IRP contains a detailed summary of the members' demand side activities and energy efficiency programs.

5.2.1 **Interruptible Loads**

UAMPS and members with their own generation have developed an interruptible load program. This program allows members to enter into an agreement with industrial customers of 1 MW or larger to become interruptible loads on the UAMPS system. The member must be able to shed the interruptible load within ten minutes of notification by UAMPS based on a firm need for other UAMPS loads or an economic decision by the industrial customer and member.

5.2.2 **Energy Audits**

The Member Services Project makes available an infrared camera and heat trace gun. These tools help the members audit their own system infrastructure and also that of their large industrial, small commercial and, sometimes, residential customers. The members use these items to identify energy losses and inefficiencies within their

system. Once identified, the members can act to mitigate the cause of the problems that leads to energy losses. System improvements help ensure better energy efficiency in their transmission and distribution systems. These upgrades typically yield the high nominal energy savings.

5.2.3 **Power Factor Modification**

UAMPS and its members have analyzed closely and reviewed their power factors and the effect on the loads. Almost every UAMPS member has worked on correcting their power factors and spent significant sums of money on power factor studies, capacitors and other system improvements to increase the power efficiency of their systems. Considerable system improvements have been implemented. For example, the Central-St. George Transmission Project located in Washington County has experienced difficulties dealing with rapid growth. Power factors have been critical in avoiding outages during the summer peak and the Project has committed to install capacitors to improve system reliability. Such power factor improvements and coordination help ensure that system outages are avoided and lower overall cost.

5.2.4 **Load Shedding**

UAMPS has developed in coordination with the members, a load shedding program during excessive system peak periods. Several advertisements and newsletters have been published, encouraging customers to cut down their use of electricity over their system peak. UAMPS also participated in PowerForward, a Utah State government sponsored program to encourage customer awareness regarding voluntary shedding load over critical system times.

UAMPS sees significant additional opportunities in the area of voluntary and economic load reduction measures. UAMPS intends to further promote peak energy demand reduction with residential and large commercial and industrial customers.

SECTION 6 - PUBLIC PARTICIPATION

6.1 **Public Involvement Plan and Schedule**

Public involvement in this IRP development was a part of the process.

- 6.1.1 Most members participated in a joint public hearing held at UAMPS' offices. Some members conducted their own individual public participation process with support from UAMPS on an as-requested basis.
- 6.1.2 Members will be primarily responsible for addressing demand side programs associated with the plan.

6.1.3 The goal of the public participation process is not necessarily to reach consensus, but rather to inform the governing bodies by providing information and balancing input from all affected interests.

6.1.4 Each of the Members' governing board will approve the IRP with the UAMPS Board of Directors making the final decision regarding this IRP.

6.2 **Public Comment Meetings**

Public Hearings were held by each of the Members during the months of November and December of 2012, and January of 2013.

6.3 **Results of Public Comment Meetings**

No specific changes were recommended from any public meeting.

6.4 **Summary**

No comments were received from the public as a result of the public hearings held thus far. However, this IRP attempts to address the concerns received in relation to prior public polling and IRP processes, namely that the public desires to keep rates low and stable, while mitigating negative environmental impacts.

SECTION 7 – ALTERNATIVES AND RECOMMENDATIONS

7.1 **Analysis of Available Alternatives**

UAMPS has identified two categories of alternatives in response to the need of additional resource. The first category is to reduce energy demand. The second category is to acquire an additional resource.

7.1.1 **Reduce Energy Demand**

As described earlier, UAMPS has implemented a number of residential demand side programs specifically targeted to reducing energy demand and peak load to minimize the need for new resources by targeting three areas:

7.1.1.1 **Energy Efficiency**

By continuing to invest in technological measures and practices that improve the rate of energy usage, it is possible to deliver an equivalent or improved level of service with less energy waste.

7.1.1.2 Energy Conservation

Conservation avoids the use of electricity without eliminating its need, usually at the expense of service. Conservation measures generally take the form of appeals to the public to curtail energy usage voluntarily. UAMPS anticipates using education along with other incentives to reduce or avoid demand.

7.1.1.3 Load Management

- Net Metering
- Small wind
- Residential and Commercial Solar
- Other demand-side programs.

7.1.2 **Acquire Additional Resource**

UAMPS has a forecasted need for additional capacity and energy with the 10 year forecast period. This need is a result of number of factors the directly affect UAMPS resource portfolio including but not limited to the following:

- Load growth assumptions in the last IRP period were exceptionally high. Those assumptions will be tempered this period due to lower growth and stagnant economic conditions. Establish DSM and energy efficiency programs have partially mitigated resource needs during the last IRP period. Due to difficult economic conditions during the last IRP period, load growth assumptions have effectively been put off by five years. However, moving forward there is a need to add capacity, although a much more tempered pace.
- Political and regulatory uncertainties of coal and the economic costs associated with clean air compliance of aging coal assets, have forced UAMPS to reevaluate additional coal ownership and also to consider replacing existing coal-fired resources with other sources of power generation.
- UAMPS does foresee rigorous reliability standards that may require more installed system capacity for reliability purposes.

Therefore, UAMPS will likely need to acquire additional system resources to provide energy and capacity. These resources may include any combination of the following:

7.1.2.1 Renewable resources; geothermal or additional wind

Renewable resources meet many of the selection criteria but may not be available in the quantity or quality to reliably meet forecasted load

growth. Preference is given to geothermal because of the reliable nature of generation, but cost a possible barrier. Wind energy is acceptable, but the intermittent nature is may not provide the necessary capacity or energy for load and reliability. Geothermal resources are difficult due to extremely high capital and operating costs. Solar has an attractive generation profile, but despite the precipitous decline in panel costs, cost still is often prohibitively high.

7.1.2.2 Coal-fired power

Low variable cost, fuel availability, reliability and the economy of scale are the primary drivers of coal. UAMPS sees coal as an integral part of meeting future load growth. Future environmental regulation risks appear surmountable with the continual development of “clean” coal technologies. High capital costs are overcome by low fuel costs and the nature of base load operations.

7.1.2.3 Additional gas-fired power

Natural gas generation is an excellent option for meeting intermediate and peak load growth will providing the capacity that is necessary to meet potential reliability standards. Natural gas generation can be built in numerous sizes and configurations based on the organizational needs. Higher fixed costs are often mitigated by lower variable cost and the operational flexibility of the plants. Relatively low forecasted gas prices due to exploration and drilling technologies and the availability of long-term, low-cost fuel supply make gas-fired generation an attractive resource.

7.1.3.4 Market-based Power Purchases

Power purchases are good option to meet short-term needs but usually lack operating flexibility. Market power purchases are usually an excellent way to meet short-term base load needs and to bridge needs until a long-term solution is in place.

7.2 Recommendations

The following recommendations intend to fit within the objectives of providing a reliable, least-cost, electrical energy supply portfolio for the next five to ten years. Each recommendation outlines the general directions that UAMPS should follow in order to meet these objectives. Accordingly, each recommendation provides guidance to UAMPS and its members and should be followed up with additional detailed analysis and planning before the recommendations can be fully implemented.

7.2.1 **Recommendation 1 – Demand Side Programs**

UAMPS and its members should implement a comprehensive Demand Side Management Plan. The plan should take into account cost-effective measures that will reduce the growth of member peak demand, encourage efficient use of electricity resources while keeping rates low, maintaining reliability and enhancing services to the Members' customers. The intent of this program is to reduce demand and act as additional resources to meet the Members immediate needs to serve existing system loads.

UAMPS' members have already taken the first step by directing UAMPS to focus on demand-side management. UAMPS' members have recently put in place DSM programs which effectively encourage energy efficiency, promote conservation and effectively reduce energy demand.

UAMPS' members are encouraged to exercise the broad authority they possess to the extent they can, to educate, implement, and enforce any DSM program recommended by UAMPS.

7.2.2 **Recommendation 2 – Additional Resources**

UAMPS should pursue the development of additional resources with an emphasis on renewable resources in the form of wind geothermal and landfill gas power. Specific qualitative and quantitative criteria should be established and adopted by the resource committee for evaluating additional renewable resources. UAMPS should also pursue options for acquiring additional base, intermediate and peaking resources for future energy and reliability needs.

UAMPS will encourage the development of renewable thermal generation to incorporate as a base load resource in its portfolio. UAMPS will also continue to pursue the development of additional wind generation to the extent it meets selection criteria.

Members will continue to review renewable resource alternatives within their service area. At this time, small hydroelectric, biogas, and solar energy technologies appear to have good potential.

In view of the growth and the associated increase of peak loads, along with the potential needs of capacity for reliability purposes, UAMPS should consider additional gas-fired resources. Additional gas-fired generation will help meet forecasted intermediate and peaking needs for its members. These resources would also provide the capacity that potentially may be needed to meet reliability standards that may be imposed on UAMPS.

UAMPS will continue to evaluate new base load resources to meet the long-term shortfall in resources.

The intent of additional base, intermediate and peaking resource acquisitions is to meet the member's long-term needs associated with forecasted system load growth. The timing of decisions on specific resources will be determined by the UAMPS Board of Directors

7.3 **Conclusion**

This IRP was completed to present an approach for ensuring continued cost effective, reliable and environmentally sensitive service to UAMPS and its members and to gather additional public input on the planning process. This IRP was presented to the members. UAMPS and its members plan to continue this joint planning process and will likely build upon and update this IRP on an annual basis.

KAYSVILLE CITY

KAYSVILLE CITY POWER AND LIGHT DEMAND SIDE MANAGEMENT PROGRAM

Kaysville City Power and Light has implemented some new plans to help manage the demand put on our system. In Kaysville we are purchasing, installing and utilizing excellent equipment including low loss transformers in all residential and commercial applications. Infrared cameras are run 2-3 weeks per year in order to help find, identify and repair problems areas in which line loss or inefficiencies could create an issue. Capacitor banks are also visible around town near the end of lines where they are needed to help keep the power factor up in an efficient range. Recently Kaysville City Power and Light completed a new substation including a 10.4 m W transformer to further balance our load throughout town.

Kaysville City Power and Light has a system that is constantly improving. An extensive tree trimming plan is being executed. This program helps limit the number of outages as well as shortening the length of time customers are out of power. The older part of Kaysville's system is 4KV; this part of town is undergoing a continual rebuild to upgrade the system to 12KV. Studies are also being performed throughout the system to help break up and balance circuits, also preventing line loss and overloading. Kaysville is replacing a 7,500KVA 4160 Volt Substation Transformer with a 10,000KVA 12,000 Volt Substation Transformer as part of ongoing voltage upgrades to improve line losses and voltage and reliability.

In order to encourage Kaysville residential customers to conserve energy in the future a rate adjustment has been adopted. The first 1000 Kwh the customer is charge \$.090/kwh. All additional power used is \$.1085/kwh. Kaysville has a bi-annual newsletter specifically for Power and Water conservation, the newsletter offers tips and suggestions for our customers in order to help them conserve energy and save money.

Kaysville City currently participates in the UAMPS Smart Energy programs:

- Home energy savings program – cash back for purchasing qualifying appliances
- Cool Cash – Incentive to install efficient evaporative or central air cooling systems
- See “ya” later refrigerator – Incentive to replace inefficient refrigerators or freezers

Kaysville City also signed up with Enerlyte to publish energy efficiency and energy conservation data on all utility bills comparing usage to those in the community with similar demographics encouraging conservation.

Kaysville City Power and Light's demand side management program is an ever evolving work in progress. New ideas are welcomed and rewarded. Kaysville is a dynamic utility, focused on forward movement and always open to conservation programs

RECEIVED

JAN 16 2013

**KAYSVILLE CITY
PUBLIC HEARING NOTICE**

U.A.M.P.S.

Kaysville City hereby gives notice to their customers that Kaysville City is taking written comments on the Utah Associated Municipal Power Systems ("UAMPS") Integrated Resource Plan ("IRP"). A Public Hearing will be held January 3, 2013 at 1:00 p.m. at the UAMPS office at 155 North 400 West, Suite 480, Salt Lake City, Utah. Persons interested in providing input should submit written comment at or before the Public Hearing to Bruce Rigby at Kaysville City Corporation, 23 East Center Street, Kaysville, Utah 84037. The IRP is available at the Kaysville City offices for review on Thursday, December 20, 2012.

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PUBLIC HEARING NOTICE**

Kaysville City hereby gives notice to their customers that Kaysville City is taking written comments on the Utah Associated Municipal Power Systems ("UAMPS") Integrated Resource Plan ("IRP"). A Public Hearing will be held January 3, 2013 at 1:00 p.m. at the UAMPS office at 155 North 400 West, Suite 480, Salt Lake City, Utah. Persons interested in providing input should submit written comment at or before the Public Hearing to Bruce Rigby at Kaysville City Corporation, 23 East Center Street, Kaysville, Utah 84037. The IRP is available at the Kaysville City offices for review on Thursday, December 20, 2012.

C-8804 12/13

**A RESOLUTION APPROVING THE
UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS
INTEGRATED RESOURCE PLAN**

WHEREAS, Kaysville City is a Member of Utah Associated Municipal Power Systems ("UAMPS") pursuant to the provisions of the Amended and Restated Agreement for Joint and Cooperative Action;

WHEREAS, UAMPS and Western Area Power Administration ("Western") have entered into Contract No. 87-SLC-0039, as amended (the "Integrated Contract") that provides for *inter alia*, the submittal by UAMPS of an Integrated Resource Plan (the "IRP");

WHEREAS, UAMPS and Kaysville City, along with other Members of UAMPS with allocations of CRSP power and energy, have formed the CRSP Project of UAMPS (the "CRSP Project") through the CRSP PROJECT POWER SUPPLY AGREEMENT BETWEEN UAMPS AND Kaysville City to provide for the coordinated management of the Integrated Contract, for the benefit of the Members;

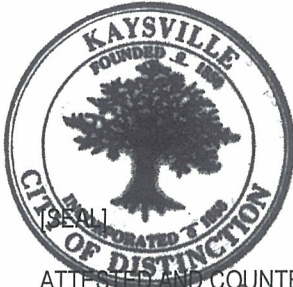
WHEREAS, UAMPS pursuant to the direction of the Members of the CRSP Project requested and was approved for a filing status of an IRP Cooperative in order to file one joint IRP on behalf of the Members of the CRSP Project; and

WHEREAS, Western requires the participation and approval of each participant in the IRP Cooperative.

NOW, THEREFORE, BE IT RESOLVED by the [City Council, Town Council or Board of Directors] of Kaysville City as follows:

1. Kaysville City, as a Member of the CRSP Project of UAMPS, has participated fully in the development of the UAMPS' IRP through exchange of information, multiple review of draft documents and holding meetings for public participation.
2. Kaysville City has reviewed the final UAMPS IRP and finds that the data and conclusions accurately represent the planning needed under the requirements of the Western IRP Program.
3. Kaysville City approves the UAMPS IRP for submittal to the UAMPS Board of Directors and Western.

ADOPTED AND APPROVED this 5 day of February, 2013.



ATTESTED AND COUNTERSIGN

Juda Ross
City Recorder

Kaysville City

[Signature]
Mayor

After you have looked at the Rate Study and the Avoided cost Alternatives, please watch the presentations that were given to the City Council by UFS (The company that did both of these study's)

You can find them on the Kaysville City web site under Mayor& City Council, Agenda & minutes. Then go to the dates. Rate study April 21st 2016 & Avoided Cost Alternatives (Solar discussion) October 20th, 2016 and watch the videos. After everyone has had a chance to look at them, I suggest that you talk to each other and put together a condensed list of questions for UFS and we will have them on the phone to answer questions at our next meeting.

Electric meters by class as of January 2017

	# of meters
Residential	8538
Commercial single phase	425
Commercial 3 phase	316
Industrial	1
City owned	62
Net Meters	130
Total	9472

Percentage of Carbon free resources by month

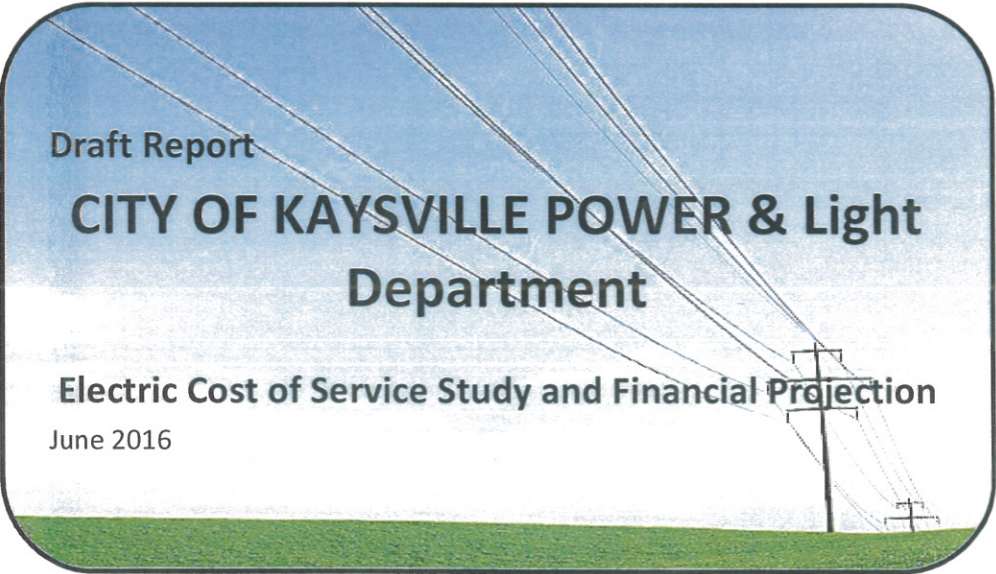
January	22%
February	27%
March	27%
April	23%
May	19%
June	15%
July	15%
August	13%
September	19%
October	35%
November	29%
December	29%
Average	23%

Carbon free resources included

Horse Butte wind project
Pleasant valley wind
Colorado River storage project (Hydro)
Veyo (Heat recovery)

8 Resources

	Fuel source	Average % of Load (KWH)	Average cost KWH	Life of plant or contract
IPP	Coal	Taking 0 % at this time.		Repowering to natural gas by 2027
CRSP	Hydro	7%	3.1¢	Contract-2024 Preparing new 40 year contracts
Hunter II	Coal	32%	4.¢	We have a % of ownership and depends on EPA and other factors
San Juan	Coal	4%	9.5¢	Bonds paid off in 2023
PV Wind	Wind	4%	6.9¢	Contract-2028
Nebo	Natural Gas	41%	7.9¢	We have % of ownership. Depends on condition and long term maintenance Bonds paid off in 2026
HB Wind	Wind	12%	7.9¢	Life-30 plus years. Came online in Septmber of 2012. Bonds paid off in 2032
Veyo	Heat Recovery	new resource		Life 30 plus years. Bonds paid off in 2041
	Total	100%	6.55¢	



Draft Report

CITY OF KAYSVILLE POWER & Light Department

Electric Cost of Service Study and Financial Projection

June 2016



Utility Financial Solutions, LLC

**Specializing in Cost of Service,
Rate Design, and Financial Analysis**

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June 2016

Mr. Bruce Rigby
Resource Manager
City of Kaysville Power & Light Department
23 East Center
Kaysville, UT 84037

Dear Mr. Rigby;

We are pleased to present the Draft Report for the electric cost of service study and financial projection for the City of Kaysville Power & Light Department (Power & Light). This report was prepared to provide the Power & Light with a comprehensive examination of its existing rate structure by an outside party.

The specific purposes of this rate study are:

- Determine electric utility's revenue requirements for fiscal year 2017
- Identify cross-subsidies that may exist between rate classes
- Recommend rate adjustments needed to meet targeted revenue requirements
- Identify the appropriate monthly customer charge for each customer class

This report includes results of the electric cost of service study and financial projection and recommendations on future rate designs.

This report is intended for information and use by the utility and management for the purposes stated above and is not intended to be used by anyone except the specified parties.

Sincerely,

A handwritten signature in black ink, which appears to read "Mark Beauchamp", is written over a horizontal line.

Utility Financial Solutions, LLC
Mark Beauchamp
CPA, MBA, CMA
185 Sun Meadow Ct
Holland, MI 49424

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1. Introduction

This report was prepared to provide the City of Kaysville Power & Light Department (Power & Light) with an electric cost of service study and financial projection and a comprehensive examination of its existing rate structure by an outside party. The specific purposes of the study are identified below:

- 1) **Determine electric utility's revenue requirements for fiscal year 2017.** Power & Light's revenue requirements were projected for the period from 2017 – 2021 and included adjustments for the following:
 - a. Projected power costs
 - b. Projected changes in staffing levels
 - c. Capital improvement plan projected over next five years
- 2) **Identify cross-subsidies that may exist between rate classes.** Cross-subsidies exist when certain customer classes subsidize the electric costs of other customers. The rate study identifies if cross-subsidies exist and practical ways to reduce the subsidies. The cost of service study was completed using 2017 projected revenues and expenses. The financial projections are for the period from 2017 – 2021.
- 3) **Recommend rate adjustments needed to meet targeted revenue requirements.** The primary purpose of this study is to identify appropriate revenue requirements and the rate adjustments needed to meet targeted revenue requirements. The report includes a long-term rate track for Power & Light to help ensure the financial stability of the utility in future years.
- 4) **Unbundled electric rates.** The cost of providing electricity to customers consists of a number of components, including power generation, distribution, customer services, transmission, and transfers to the general fund. Electric unbundling identifies the cost of each component to assist the utility in preparing for electric restructuring and understanding its cost structure.
- 5) **Identify the appropriate monthly customer charge for each customer class.** The monthly customer charge consists of fixed costs to service customers that do not vary based on the amount of electricity used.

2. Cost of Service Summary

Utility Rate Process

Power & Light retained Utility Financial Solutions to review utility rates and cost of service and make recommendations on the appropriate course of action. This report includes results of the electric cost of service and unbundling study and recommendations on future rate designs.

Utility Revenue Requirements

To determine revenue requirements, the revenues and expenses for Fiscal Years 2013, 2014 and 2015, 2016 budget were analyzed, with adjustments made to reflect projected operating characteristics. ***The projected financial statements are for cost of service purposes only.***

Table 1 is the projected financial statement for the Electric Department from 2017-2021. The 2017 rate of return calculation established an operating income target of \$980K (See Table 5).

Operating income for 2017 is projected at \$(1M) and decreases to \$(2.4M) in 2021. Operating income is one target that helps to determine if rate adjustments are needed. The following pages review cash flow and debt coverage ratio which are also important indicators.

Table 1 – Financial Statements (without rate adjustments)

Description	Projected 2017	Projected 2018	Projected 2019	Projected 2020	Projected 2021
Operating Revenues:					
Electric Sales					
Charges for Services (Net of Uncollectables)	12,250,988	12,434,753	12,621,275	12,810,594	13,002,753
Other Revenue	100,000	102,500	105,063	107,689	110,381
Operating Revenue	\$ 12,350,988	\$ 12,537,253	\$ 12,726,337	\$ 12,918,283	\$ 13,113,134
Total Operating Revenues	\$ 12,350,988	\$ 12,537,253	\$ 12,726,337	\$ 12,918,283	\$ 13,113,134

Description	Projected 2017	Projected 2018	Projected 2019	Projected 2020	Projected 2021
Operating Expenses:					
Purchases					
Purchased Power (Cost of Sales and Service)	\$ 10,128,002	\$ 10,536,920	\$ 10,962,349	\$ 11,404,953	\$ 11,865,428
Total Power Supply	\$ 10,128,002	\$ 10,536,920	\$ 10,962,349	\$ 11,404,953	\$ 11,865,428
Total Power Supply Expense	\$ 10,128,002	\$ 10,536,920	\$ 10,962,349	\$ 11,404,953	\$ 11,865,428
Other Operating Expenses (Revenues)					
Personnel Services	\$ 1,279,394	\$ 1,311,379	\$ 1,344,164	\$ 1,377,768	\$ 1,412,212
Contractual Services	559,743	573,736	588,079	602,781	617,851
Administrative Charges from General Fund	173,353	177,687	182,129	186,682	191,349
Interfund Services	136,581	139,996	143,496	147,083	150,760
Supplies, Maintenance, Misc Operating	723,103	741,181	759,710	778,703	798,171
Energy Sales and Use Tax Charge	768,252	787,458	807,144	827,323	848,006
Removed Taxes (Not Included in Sales)	(768,252)	(787,458)	(807,144)	(827,323)	(848,006)
Depreciation Expense	1,089,375	1,166,648	1,219,678	1,242,406	1,265,133
Total Other Operating Expenses	\$ 3,961,550	\$ 4,110,627	\$ 4,237,257	\$ 4,335,423	\$ 4,435,476
Total Operating Expenses	\$ 14,089,552	\$ 14,647,547	\$ 15,199,605	\$ 15,740,377	\$ 16,300,905
Operating Income	\$ (1,738,564)	\$ (2,110,294)	\$ (2,473,268)	\$ (2,822,094)	\$ (3,187,771)

Description	Projected 2017	Projected 2018	Projected 2019	Projected 2020	Projected 2021
Other Income & Expense					
Revenue/(Loss) on Disposal of Capital Assets	\$ 3,066	\$ 3,082	\$ 3,097	\$ 3,113	\$ 3,128
Interest and Other Income	37,014	21,441	6,845	646	-
Impact Fees	27,475	27,613	27,751	27,889	28,029
Connection Fees	105,318	105,845	106,374	106,906	107,440
Extension Fees	607,755	610,794	613,848	616,917	620,002
Non Operating Income/Expense	\$ 786,458	\$ 774,631	\$ 763,802	\$ 761,388	\$ 764,545
Net Income	\$ (952,106)	\$ (1,335,663)	\$ (1,709,466)	\$ (2,060,706)	\$ (2,423,226)
Adjusted Operating Income	\$ (998,015)	\$ (1,366,043)	\$ (1,725,296)	\$ (2,070,382)	\$ (2,432,300)

Projected Cash Flow

Table 2 is the projected cash flow for 2017-2021, including projections of capital improvements as provided by the Power & Light. Changes in the capital improvement plan can greatly affect the cash balance and recommended minimum cash reserve target. The cash balance for 2017 is projected at \$4.2M and \$(3.35M) in 2021. The recommended minimum cash reserve level for 2017 is \$3.25M and \$3M for 2021.

Table 2 – Projected Cash Flows (without rate adjustments)

Description	Projected 2017	Projected 2018	Projected 2019	Projected 2020	Projected 2021
Projected Cash Flows					
Net Income	\$ (952,106)	\$ (1,335,663)	\$ (1,709,466)	\$ (2,060,706)	\$ (2,423,226)
Depreciation Expense/Amortization	1,089,375	1,166,648	1,219,678	1,242,406	1,265,133
Cash Available from Operations	\$ 137,269	\$ (169,015)	\$ (489,788)	\$ (818,301)	\$ (1,158,093)
Estimated Annual Capital Additions	\$ 2,350,000	\$ 2,750,000	\$ 750,000	\$ 750,000	\$ 750,000
Net Cash From Operations	\$ (2,212,731)	\$ (2,919,015)	\$ (1,239,788)	\$ (1,568,301)	\$ (1,908,093)
Beginning Cash Balance	\$ 6,500,833	\$ 4,288,102	\$ 1,369,087	\$ 129,299	\$ (1,439,001)
Ending Cash Balance	\$ 4,288,102	\$ 1,369,087	\$ 129,299	\$ (1,439,001)	\$ (3,347,094)
Total Cash Available	\$ 4,288,102	\$ 1,369,087	\$ 129,299	\$ (1,439,001)	\$ (3,347,094)
Recommended Minimum	\$ 3,253,895	\$ 3,065,123	\$ 2,778,385	\$ 2,893,759	\$ 3,011,326

Minimum Cash Reserve

Table 3 details the minimum level of cash reserves required to help ensure timely replacement of assets and to provide financial stability of the utility. The methodology used to establish this target is based on certain assumptions related to a percentage of operating expense, historical investment, capital improvements, and debt service to be kept in cash reserves. Based on these assumptions, Power & Light should maintain a minimum of \$3.25M in cash reserves for 2017 and \$3M in 2021.

Table 3 – Minimum Cash Reserves (without rate adjustments)

Description	Projected 2017	Projected 2018	Projected 2019	Projected 2020	Projected 2021
Minimum Cash Reserve Allocation					
Operation & Maintenance Less Depreciation Expense	12.3%	12.3%	12.3%	12.3%	12.3%
Purchase Power Expense	11.0%	11.0%	11.0%	11.0%	11.0%
Historical Rate Base	1%	1%	1%	1%	1%
Five Year Capital Improvements - Net of bond proceeds	20%	20%	20%	20%	20%
Calculated Minimum Cash Level					
Operation & Maintenance Less Depreciation Expense	\$ 354,104	\$ 362,956	\$ 372,030	\$ 381,331	\$ 390,864
Purchase Power Expense	1,111,481	1,156,357	1,203,045	1,251,618	1,302,152
Historical Rate Base	318,310	345,810	353,310	360,810	368,310
Five Year Capital Improvements - Net of bond proceeds	1,470,000	1,200,000	850,000	900,000	950,000
Minimum Cash Reserve Levels	\$ 3,253,895	\$ 3,065,123	\$ 2,778,385	\$ 2,893,759	\$ 3,011,326
Projected Cash Reserves	\$ 4,288,102	\$ 1,369,087	\$ 129,299	\$ (1,439,001)	\$ (3,347,094)

Projected cash balances fall below the recommended minimums during the projection period.

Debt Coverage Ratio

This section is for reference as the utility currently has no external debt. Table 4 is the projected debt coverage ratios with capital additions as provided by Power & Light. The coverage required in bond ordinances is typically 1.15 – 1.20, however the minimum recommended debt coverage ratio is established at 1.35 – 1.40 for projection purposes a 0.20 premium to ordinance. Maintaining a higher debt coverage ratio is good business practice and helps to achieve the following:

- Helps to ensure adequate funds are available to meet debt service payments in years when sales are low due to temperature fluctuations.

- Obtain higher bond rating, if revenue bonds are sold in the future, to lower interest cost.

Table 4 – Projected Debt Coverage Ratios (without rate adjustments)

Description	Projected 2017	Projected 2018	Projected 2019	Projected 2020	Projected 2021
Debt Coverage Ratio					
Net Income	\$ (952,106)	\$ (1,335,663)	\$ (1,709,466)	\$ (2,060,706)	\$ (2,423,226)
Add Depreciation/Amortization Expense	1,089,375	1,166,648	1,219,678	1,242,406	1,265,133
Add Interest Expense	-	-	-	-	-
Cash Available for Debt Service	\$ 137,269	\$ (169,015)	\$ (489,788)	\$ (818,301)	\$ (1,158,093)
Debt Principal and Interest	\$ -	\$ -	\$ -	\$ -	\$ -
Projected Debt Coverage Ratio (Covenants)	-	-	-	-	-
Minimum Debt Coverage Ratio	1.4	1.4	1.4	1.4	1.4

Rate of Return

The optimal target for setting rates is the establishment of a target operating income to help ensure the following:

- Funding of interest expense on the outstanding principal on debt. Interest expense is below the operating income line and needs to be recouped through the operating income balance.
- Funding of the inflationary increase on the assets invested in the system. The inflation on the replacement of assets invested in the utility should be recouped through the Operating Income.
- Funding of depreciation expense.
- Adequate rate of return on investment to help ensure current customers are paying their fair share of the use of the infrastructure and not deferring the charge to future generations.

As improvements are made to the system, the optimal operating income target will increase unless annual depreciation expense is greater than yearly capital improvements. The revenue requirements for the study are set on the utility basis. Table 5 identifies the utility basis target established for 2017 is \$980K and increases to \$1.14M in 2021.

Table 5 – Rate of Return Calculation

Description	Projected 2017	Projected 2018	Projected 2019	Projected 2020	Projected 2021
Target Operating Income Determinants					
Net Book Value/Working Capital	\$ 18,742,893	\$ 20,326,245	\$ 19,856,566	\$ 19,364,161	\$ 18,849,027
System Equity	\$ 18,742,893	\$ 20,326,245	\$ 19,856,566	\$ 19,364,161	\$ 18,849,027
Target Operating Income Allocation					
System Equity	5.26%	5.27%	5.52%	5.78%	6.06%
Target Operating Income					
System Equity	\$ 986,760	\$ 1,072,010	\$ 1,095,260	\$ 1,118,510	\$ 1,141,760
Target Operating Income	\$ 986,760	\$ 1,072,010	\$ 1,095,260	\$ 1,118,510	\$ 1,141,760
Projected Operating Income	\$ (998,015)	\$ (1,366,043)	\$ (1,725,296)	\$ (2,070,382)	\$ (2,432,300)
Rate of Return in %	5.3%	5.3%	5.5%	5.8%	6.1%

Recommended Rate Track

The study identifies increasing current revenues in 2017, and increase annually thereafter to maintain minimum cash targets and movement toward target operating income. Table 6 is a summary of the financial results detailing the recommended revenue adjustments required to meet target operating income.

Table 6 – Recommended Revenue Adjustments

Fiscal Year	Projected Rate Adjustments	Projected Expenses	Projected Revenues	Adjusted Operating Income	Target Operating Income	Projected Cash Balances	Recommended Minimum Cash
2017	4.4%	\$ 14,089,552	\$ 12,890,032	\$ (458,972)	\$ 986,760	\$ 4,827,146	\$ 3,253,895
2018	4.4%	14,647,547	13,655,585	(247,711)	1,072,010	3,029,158	3,065,123
2019	4.4%	15,199,605	14,466,725	15,092	1,095,260	3,538,058	2,778,385
2020	2.2%	15,740,377	15,005,472	16,808	1,118,510	4,073,991	2,893,759
2021	2.2%	16,300,905	15,564,299	18,865	1,141,760	4,637,433	3,011,326

Cost of Service Summary Results

A cost of service study was completed to determine the cost of providing service to each class of customers and to assist in design of electric rates for customers. A cost of service study consists of the following general steps:

- 1) Determine utility revenue requirement for test year 2017
- 2) Classify utility expenses into common cost pools
- 3) Allocate costs to customer classes based on the classes' contribution to utility expenses
- 4) Compare revenues received from each class to the cost of service

The cost of service summary is included as Table 7 which compares the projected cost to serve each class with the revenue received from each class. The "% change" column is the revenue adjustment necessary to meet projected cost of service requirements. The cost of service summary uses the current rates including any adjustment factors.

Table 7 – Cost of Service Summary

Customer Class	Cost of Service	Projected Revenues	% Change
Residential	\$ 8,912,364	\$ 8,210,895	8.5%
Commercial	4,973,222	3,765,593	32.1%
Industrial	190,332	124,755	52.6%
Area Lights	14,425	13,308	8.4%
Street Lights	145,421	136,437	6.6%
Total	\$ 14,235,764	\$ 12,250,988	16.2%

Cost of Service Results

Table 8 shows the average cost of service per kWh and compares the cost to the average revenue per kWh for each customer class.

Table 8 – Average Cost per kWh vs. Average Revenue per kWh

Customer Class	Cost of Service \$/kWh	Projected Revenues \$/kWh
Residential	\$ 0.1023	\$ 0.0943
Commercial	0.1082	0.0820
Industrial	0.1035	0.0679
Area Lights	0.1695	0.1563
Street Lights	0.2933	0.2752

Cost differences result from usage patterns of customers and how efficiently each class of customer use facilities based on load data provided by Power & Light.

Distribution Costs

Separation of distribution cost helps identify distribution charges for each customer class and the fixed monthly customer charge. Distribution rates include separation of the following costs:

- Operation and maintenance of distribution & transmission system
- Contributions to general fund
- Customer service
- Customer accounting
- Meter reading
- Billing
- Meter operation & maintenance
- Administrative expenses

The distribution rates consist of two components:

- Monthly customer charge to recover the costs of meter reading, billing, customer service, and a portion of maintenance and operations of the distribution system.
- Distribution rate based on billing parameter, (kW or kWh) to recover the cost to operate and maintain the distribution system. Table 9 identifies the cost-based distribution rates for customer classes.

Table 9 – Distribution Costs by Customer Class (COS)

Customer Class	Monthly Customer		Distribution	
	Charge		Rate	Billing Basis
Residential	\$ 13.05	\$	0.0159	kWh
Commercial	53.62		4.4955	kW
Industrial	139.20		4.2798	kW

Power Supply Costs

Table 10 identifies the average cost of providing power supply to customers of Power & Light.

Table 10 – Power Supply Costs by Customer Class

Customer Class	Demand		Billing Basis	Energy		Billing Basis
Residential	\$ 0.0261		kWh	\$ 0.0452		kWh
Commercial	9.99		KW	0.0449		kWh
Industrial	9.51		KW	0.0441		kWh

Combined Cost Summary

Table 11 identifies the cost of service rates for each customer class. Charging these rates would directly match the cost of providing service to customers identified in this study.

Table 11 – Total Costs by Customer Class

Customer Class	Current Customer		COS Customer		Demand	Energy
	Charge		Charge			
Residential	\$ -	\$	13.05	\$ -	\$	0.0873
Commercial	-		53.62	\$ 14.49		0.0449
Industrial	-		139.20	\$ 13.79		0.0441

3. Functionalization of Costs

Delivery of electricity consists of many components that bring electricity from the power supply facilities to the communities and eventually into customer facilities. The facilities consist of four major components: transmission, distribution, customer-related services, and administration. Following are general descriptions of each of these facilities and the sub-breakdowns within each category.

Transmission

The transmission system is comprised of four types of subsystems that operate together:

- 1) Backbone and inter-tie transmission facilities are the network of high voltage facilities through which a utility's major production sources are integrated.
- 2) Generation set-up facilities are the substations through which power is transformed from a utility's generation voltages to its various transmission voltages.
- 3) Sub-transmission plant consists of lower voltage facilities to transfer electric energy from convenient points on a utility's backbone system to its distribution system.
- 4) Radial transmission facilities are those that are not networked with other transmission lines but are used to serve specific loads directly.

Operation of the transmission system also consists of providing certain services that ensure a stable supply of power. These services are typically referred to as ancillary services. The Federal Energy Regulatory Commission (FERC) has defined six ancillary service charges for the use of transmission facilities. For Power & Light, these charges will be passed-through charges by the control area operator. Ancillary services consist of the following:

- **Mandatory Ancillary Service Charges:**
 - Reactive Supply and Voltage Control
 - Regulation and Frequency Response Service
 - Energy Imbalance Charges
 - Operating Reserves Spinning
 - Operating Reserves Supplemental
 - Reactive Power Supply

Terminology of Cost of Service

FUNCTIONALIZATION – Cost data arranged by functional category (e.g. power supply, transmission, distribution)

CLASSIFICATION – Assignment of functionalized costs to cost components (e.g. demand, energy and customer related).

ALLOCATION – Allocating classified costs to each class of service based on each class's contribution to that specific cost component.

DEMAND COSTS – Costs that vary with the maximum or peak usage. Measured in kilowatts (kW)

ENERGY COSTS – Costs that vary over an extended period of time. Measured in kilowatt-hours (kWh)

CUSTOMER COSTS – Costs that vary with the number of customers on the system, e.g. metering costs.

DIRECT ASSIGNMENT – Costs identified as belonging to a specific customer or group of customers.

Power losses from use of transmission system

Distribution

The distribution facilities connect the customer with the transmission grid to provide the customer with access to the electrical power that has been generated and transmitted. The distribution plant includes substations, primary and secondary conductors, poles, and line transformers that are jointly used and in the public right-of-way.

Substations typically separate the distribution plant from the transmission system. The substation power transformer “steps down” the voltage to a level that is more practical to install on and under city streets.

Distribution circuits are divided into primary and secondary voltages with the primary voltages usually ranging between 35 kV and 4 kV and the secondary below 4 kV.

Distribution Customer Types

Sub-transmission customers are served directly from the substation feeder and bypass both the secondary and primary distribution lines. The charges for this type of customer should reflect the cost of the substation and not include the cost of primary or secondary line charges.

Primary customers are typically referred to as customers who have purchased, owned, and maintained their own transformers that convert the voltage to the secondary voltage level. The rates for these customers should reflect the cost of substations and the cost of primary distribution lines and not include the cost of secondary line extensions.

Secondary customers have the services provided by the utilities directly into their facilities. The utility provides the customer with the transformer and the connection on the customers’ facilities.

Customer-Related Services

Certain administrative-type services are necessary to ensure customers are provided service connections and disconnections in a timely manner and the facilities are in place to read meters and bill for customer usages. These services typically consist of the following components:

- Customer Services – The cost of providing personnel to assist customers with questions and dispatch personnel to connect and disconnect meters.
- Billing and Collections – The cost of billing and collections personnel, postage, and supplies.
- Meter Reading – The cost of reading customers’ meters.
- Meter Operation and Maintenance – The cost of installing and maintaining customer meters.

Administrative Services

These costs are sometimes referred to as overhead costs and relate to functions that cannot be directly-attributed to any service. These costs are spread to the other services through an allocator such as labor, expenses, or total rate base. These costs may consist of City Commission expenses, property insurance, and wages for higher level management of the utility.

System Losses

As energy moves through each component of the transmission and distribution system, some of the power is lost and cannot be sold to customers. Losses vary based on time of day and season. Typically, as system usage increases or ambient temperature increases, the percentages of losses that occur also increase. These losses are recovered from distribution customers through an analysis of the peak losses that occur in the system. The average system losses and unaccounted for energy for Power & Light are approximately 6%. (Typical municipal system losses are approximately 5.4%)

4. Unbundling Process

The cost of power supply, distribution, and customer services are identified as part of the unbundling process and are the first step in determining unbundled charges to customers. The total revenue requirements of \$14.2M are separated into three categories identified in Table 12.

Table 12 – Breakdown of Power & Light Cost Structure

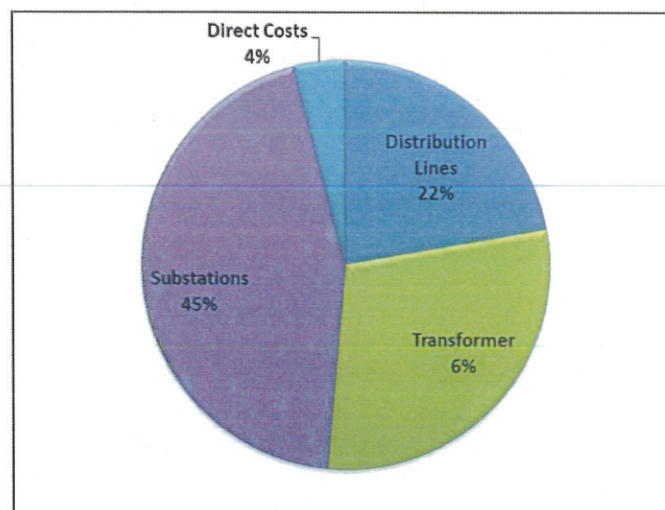
Expense Type	Amount	Percentage
Power Supply	\$ 10,128,002	71.1%
Distribution/Transmission	3,267,846	23.0%
Customer Service	839,916	5.9%
Total	\$ 14,235,764	100.0%

Power & Light is projected to expend 71.1% of its total costs toward power supply. Distribution/transmission-related costs are 23%; and customer service 5.9%. These components are broken down into each of the subcomponents and are identified in the following sections.

Distribution Breakdown

Distribution rates consist of a number of different components. Total distribution-related costs of \$3.26M for 2017 are broken down into the main components including substations, transformers, transmission, and distribution lines. Figure 1 shows the breakdown of distribution components identified in the study.

Figure 1 – Breakdown of Distribution Costs

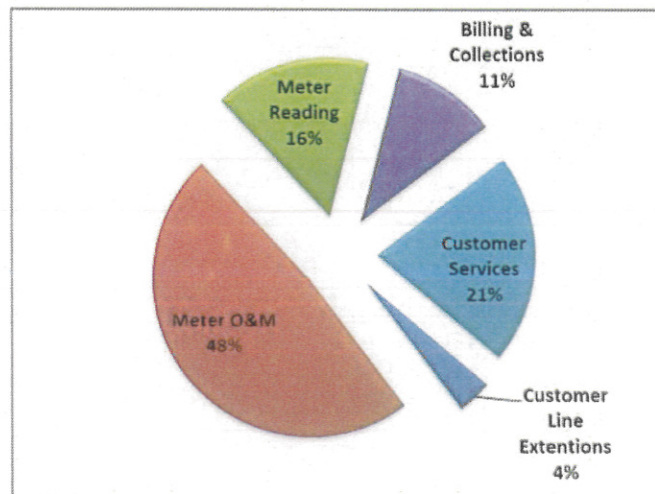


Each of these components is allocated to customer groups based on certain factors established in the study. These factors are based on the efficiency of each customer class and the time of day or the season the electricity is used. Other factors are also considered, such as the length of line extensions to reach certain customer classes.

Customer-Related Cost Breakdown

Power & Light total expenses for customer-related costs are \$840K for 2017. The cost is broken down into the components identified in Figure 2.

Figure 2 – Breakdown of Customer Costs



Power Supply Cost Breakdown

Power supply costs for 2017 were made up of purchased power and fuel and internal generation expenses.

5. Significant Assumptions

This section outlines the procedures used to develop the cost of service and unbundling study for Power & Light and the related significant assumptions.

Forecasted Operating Expenses

Forecasted expenses were based on 2013, 2014 and 2015, 2016 budget adjusted for power supply costs and inflation. The table below is a summary of the expenses used in the analysis; the projected operating expenses include an adjustment for any city contributions.

Table 13 – Projected Operating Expenses for 2017– 2021

Description	Projected 2017	Projected 2018	Projected 2019	Projected 2020	Projected 2021
Operating Expenses:					
Purchases					
Purchased Power (Cost of Sales and Service)	\$ 10,128,002	\$ 10,536,920	\$ 10,962,349	\$ 11,404,953	\$ 11,865,428
Total Power Supply	\$ 10,128,002	\$ 10,536,920	\$ 10,962,349	\$ 11,404,953	\$ 11,865,428
Total Power Supply Expense	\$ 10,128,002	\$ 10,536,920	\$ 10,962,349	\$ 11,404,953	\$ 11,865,428
Other Operating Expenses (Revenues)					
Personnel Services	\$ 1,279,394	\$ 1,311,379	\$ 1,344,164	\$ 1,377,768	\$ 1,412,212
Contractual Services	559,743	573,736	588,079	602,781	617,851
Administrative Charges from General Fund	173,353	177,687	182,129	186,682	191,349
Interfund Services	136,581	139,996	143,496	147,083	150,760
Supplies, Maintenance, Misc Operating	723,103	741,181	759,710	778,703	798,171
Energy Sales and Use Tax Charge	768,252	787,458	807,144	827,323	848,006
Removed Taxes (Not Included in Sales)	(768,252)	(787,458)	(807,144)	(827,323)	(848,006)
Depreciation Expense	1,089,375	1,166,648	1,219,678	1,242,406	1,265,133
Total Other Operating Expenses	\$ 3,961,550	\$ 4,110,627	\$ 4,237,257	\$ 4,335,423	\$ 4,435,476
Total Operating Expenses	\$ 14,089,552	\$ 14,647,547	\$ 15,199,605	\$ 15,740,377	\$ 16,300,905

Power supply costs from 2017 – 2021 are based on Power & Light's current charges adjusted for system growth factors and inflation.

Load Data

Load data is one of the most critical components of a cost of service study. Information from the billing statistics were used to determine the usage patterns of each customer class after reconciling revenues with financial statements to ensure a good basis for development of the study.

Annual Projection Assumptions

The kWh sales forecast is based on FY2015 actual adjusted for growth. Table 14 details growth, inflation of expenses, changes in purchase power costs and interest earned on investments.

Table 14 – Projection Annual Escalation Factors 2017– 2021

Fiscal Year	Inflation	Growth	Purchase	Investment
			Power Change	Income
2017	2.5%	1.5%	2.5%	0.5%
2018	2.5%	1.5%	2.5%	0.5%
2019	2.5%	1.5%	2.5%	0.5%
2020	2.5%	1.5%	2.5%	0.5%
2021	2.5%	1.5%	2.5%	0.5%

System Loss Factors

Losses occurring from the transmission and distribution of electricity can vary from year to year depending upon weather and system loading.

Revenue Forecast

The revenue forecast was based on FY2015 usages adjusted for growth rate assumptions.

6. Recommendations and Additional Information

We recommend that the utility move toward cost of service for each customer class.

The study indicates rate adjustments are needed to meet debt coverage, minimum cash and operating income targets. To ensure the utility meets financial targets and remains financially stable, the rate track identified in may be considered:

Table 15 – Recommended Rate Adjustments 2017– 2021

Fiscal Year	Projected Rate Adjustments	Projected Expenses	Projected Revenues	Adjusted Operating Income	Target Operating Income	Projected Cash Balances	Recommended Minimum Cash
2017	4.4%	\$ 14,089,552	\$ 12,890,032	\$ (458,972)	\$ 986,760	\$ 4,827,146	\$ 3,253,895
2018	4.4%	14,647,547	13,655,585	(247,711)	1,072,010	3,029,158	3,065,123
2019	4.4%	15,199,605	14,466,725	15,092	1,095,260	3,538,058	2,778,385
2020	2.2%	15,740,377	15,005,472	16,808	1,118,510	4,073,991	2,893,759
2021	2.2%	16,300,905	15,564,299	18,865	1,141,760	4,637,433	3,011,326

The cost of service study identified some customer classes are subsidizing other customer classes. Power & Light should consider movements toward cost of service using a bandwidth of plus or minus 2%. Using the 11.7% rate adjustment, this would result in no customer class given a rate increase greater than 13.7% and the lowest increase would be 9.7%. Table 16 identifies the cost of service charges compared with the projected current revenues for each class. Classes that indicate a lower % change than the total percentage change are providing subsidy to other customer classes, conversely customer classes with a higher % change than the total percentage are receiving subsidy.

Table 16 – Cost of Service Summary Results

Customer Class	Cost of Service	Projected Revenues	% Change
Residential	\$ 8,912,364	\$ 8,210,895	8.5%
Commercial	4,973,222	3,765,593	32.1%
Industrial	190,332	124,755	52.6%
Area Lights	14,425	13,308	8.4%
Street Lights	145,421	136,437	6.6%
Total	\$ 14,235,764	\$ 12,250,988	16.2%

We recommend Power & Light movements in the customer charges to move toward cost of service based customer charges to help ensure fixed distribution charges are collected in the customer charge. Table 17 compares the total cost of service monthly customer charges with the current charges. By charging cost of service rates for the monthly charge Power & Light reduces it risk associated with power usage fluctuations due to weather etc.

Table 17 – Customer Charge Comparison

Customer Class	Current Customer Charge	COS Customer Charge
Residential	\$ -	\$ 13.05
Commercial	-	53.62
Industrial	-	139.20

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Accountant's Compilation Report

Governing Body
City of Kaysville Power & Light Department

The accompanying forecasted statements of revenues and expenses of the City of Kaysville Power & Light Department (utility) were compiled for the year ending June 30, 2017 in accordance with guidelines established by the American Institute of Certified Public Accountants.

The purpose of this report is to assist management in forecasting revenue requirements and determining the cost to service each customer class. This report should not be used for any other purpose.

A compilation is limited to presenting, in the form of a forecast; information represented by management and does not include evaluation of support for any assumptions used in projecting revenue requirements. We have not audited the forecast and, accordingly, do not express an opinion or any other form of assurance on the statements or assumptions accompanying this report.

Differences between forecasted and actual results will occur since some assumptions may not materialize and events and circumstances may occur that were not anticipated. Some of these variations may be material. Utility Financial Solutions has no responsibility to update this report after the date of this report.

This report is intended for information and use by the governing body and management for the purposes stated above. This report is not intended to be used by anyone except the specified parties.

UTILITY FINANCIAL SOLUTIONS

Mark Beauchamp, CPA, CMA, MBA
Holland, MI
June 2016

City of Kaysville
Appendix A
Electric Rate Design

7/5/2016

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Submitted Respectfully by:
Mark Beauchamp, CPA, CMA, MBA
President, Utility Financial Solutions



City of Kaysville

Appendix A

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City of Kaysville

Appendix A

Rate Design Summary

Rate Design with Gradual Introduction of Monthly Facilities Charge

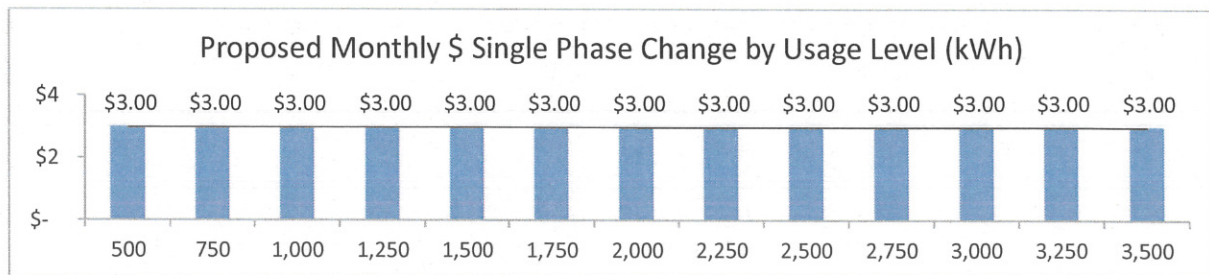
Customer Class	Rate Design		Rate Design		Rate Design	
	2017 Revenues		2018 Revenues		2019 Revenues	
Residential	\$	8,512,647	\$	8,814,399	\$	9,113,244
Commercial	\$	3,999,060	\$	4,247,002	\$	4,510,316
Industrial	\$	132,717	\$	141,235	\$	150,274
Area Lights	\$	13,797	\$	14,286	\$	14,771
Street Lights	\$	141,451	\$	146,466	\$	151,431
Total	\$	12,799,672	\$	13,363,387	\$	13,940,036
Change		4.5%		4.4%		4.3%

City of Kaysville

Appendix A

Residential Rate Design Summary (FY2017)

Current Rates		Proposed Rates (FY2017)	
Monthly Customer Charge:		Monthly Customer Charge:	
Facilities Charge	\$ -	Facilities Charge	\$ 3.00
Energy Charge:		Energy Charge:	
Block 1 (0 kWh - 1,000 kWh)	\$ 0.0907	Block 1 (0 kWh - 1,000 kWh)	\$ 0.0907
Block 2 (Excess)	\$ 0.1095	Block 2 (Excess)	\$ 0.1095
Revenues From Current Rates		Revenues From Proposed Rates	\$ 8,512,647
		Change from Current Revenues	3.7%



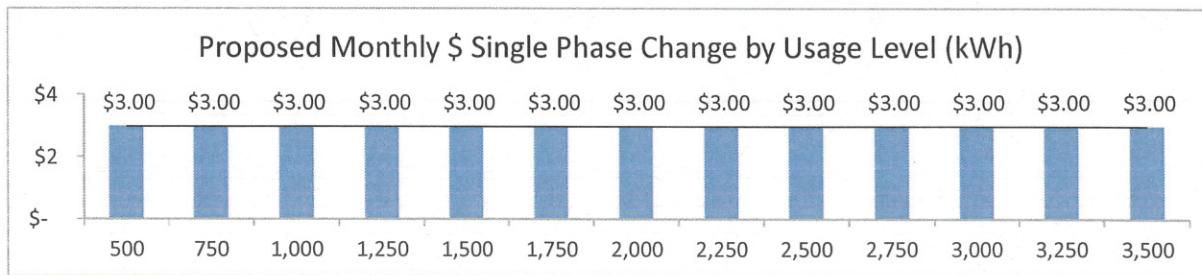
City of Kaysville

Appendix A

Residential Rate Design Summary (FY2018)

Proposed Rates (FY2017)	
Monthly Customer Charge:	
Facilities Charge	\$ 3.00
Energy Charge:	
Block 1 (0 kWh - 1,000 kWh)	\$ 0.0907
Block 2 (Excess)	\$ 0.1095
Revenues From Current Rates	\$ 8,512,647

Proposed Rates (FY2018)	
Monthly Customer Charge:	
Facilities Charge	\$ 6.00
Energy Charge:	
Block 1 (0 kWh - 1,000 kWh)	\$ 0.0907
Block 2 (Excess)	\$ 0.1095
Revenues From Proposed Rates	\$ 8,814,399
Change from Current Revenues	3.5%



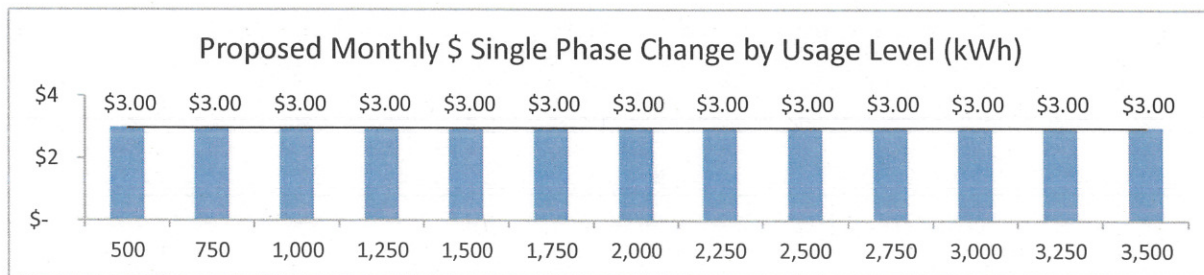
City of Kaysville

Appendix A

Residential Rate Design Summary (FY2019)

Proposed Rates (FY2018)	
Monthly Customer Charge:	
Facilities Charge	\$ 6.00
Energy Charge:	
Block 1 (0 kWh - 1,000 kWh)	\$ 0.0907
Block 2 (Excess)	\$ 0.1095
Revenues From Current Rates	\$ 8,814,399

Proposed Rates (FY2019)	
Monthly Customer Charge:	
Facilities Charge	\$ 9.00
Energy Charge:	
Block 1 (0 kWh - 1,000 kWh)	\$ 0.0907
Block 2 (Excess)	\$ 0.1095
Revenues From Proposed Rates	\$ 9,113,244
Change from Current Revenues	3.4%

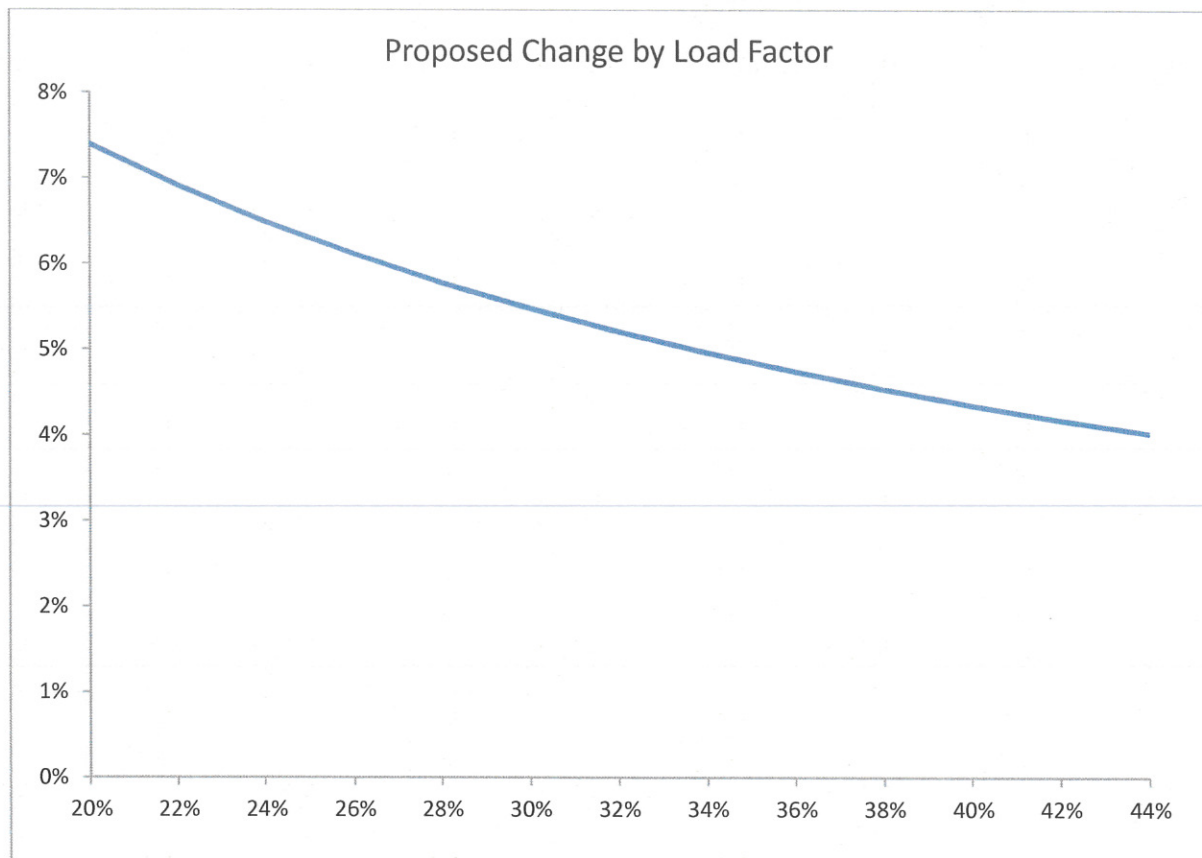


City of Kaysville

Appendix A

Commercial Rate Design Summary (FY2017)

Current Rates			Proposed Rates (FY2017)		
Monthly Customer Charge:			Monthly Customer Charge:		
All Customers	\$	-	All Customers	\$	-
3 Phase	\$	-	3 Phase	\$	-
Facilities Charge (Single Phase)	\$	-	Facilities Charge (Single Phase)	\$	10.00
Facilities Charge (Three Phase)	\$	-	Facilities Charge (Three Phase)	\$	12.50
Energy Charge:			Energy Charge:		
First 1,000 kWh	\$	0.0907	First 1,000 kWh	\$	0.0889
Next 9,000 kWh	\$	0.0655	Next 9,000 kWh	\$	0.0655
All Additional Energy	\$	0.0478	All Additional Energy	\$	0.0486
Demand Charge:			Demand Charge:		
First 8 kW of Demand	\$	-	First 8 kW of Demand	\$	-
All Other Demand	\$	8.06	All Other Demand	\$	9.00
Revenues From Current Rates	\$	3,765,757	Revenues From Proposed Rates	\$	3,999,060
			Change from Current Revenues		6.2%

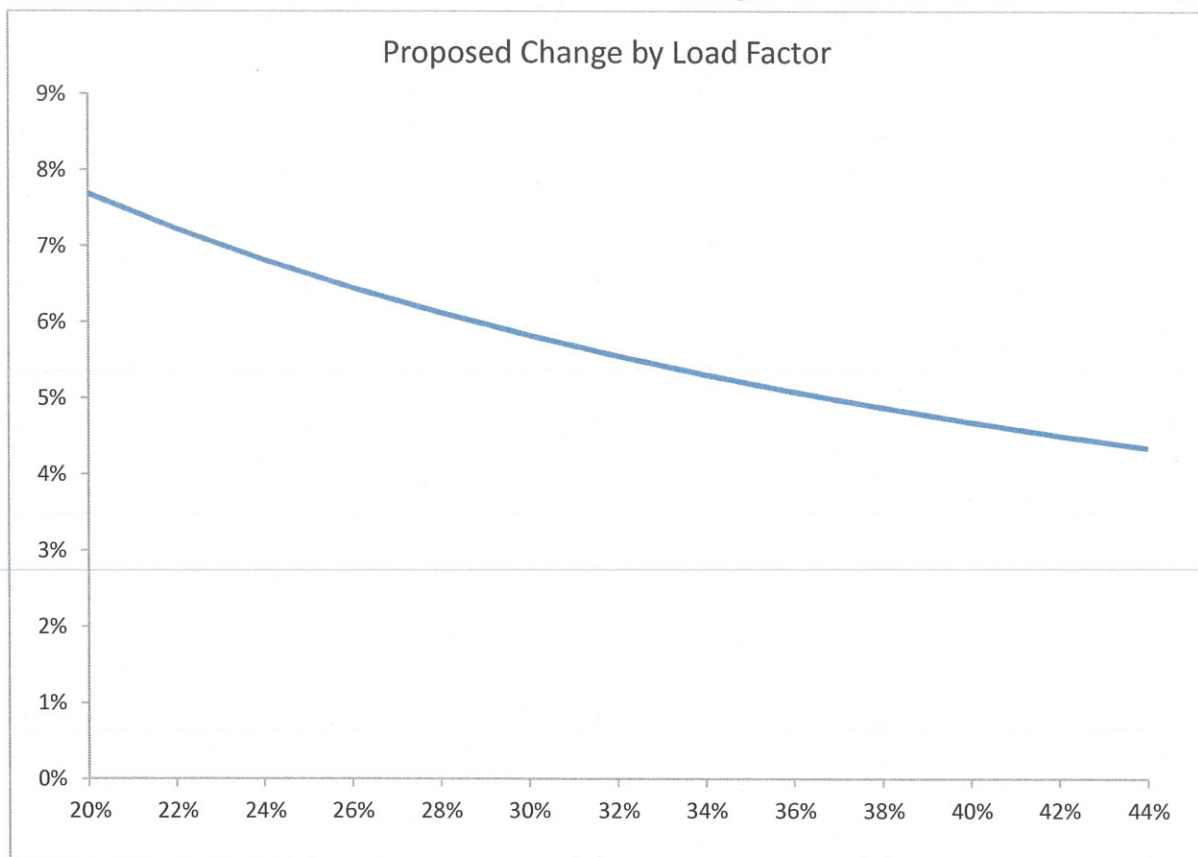


City of Kaysville

Appendix A

Commercial Rate Design Summary (FY2018)

Proposed Rates (FY2017)		Proposed Rates (FY2018)	
Monthly Customer Charge:		Monthly Customer Charge:	
Facilities Charge (Single Phase)	\$ 10.00	Facilities Charge (Single Phase)	\$ 20.00
Facilities Charge (Three Phase)	\$ 12.50	Facilities Charge (Three Phase)	\$ 25.00
Energy Charge:		Energy Charge:	
First 1,000 kWh	\$ 0.0889	First 1,000 kWh	\$ 0.0859
Next 9,000 kWh	\$ 0.0655	Next 9,000 kWh	\$ 0.0655
All Additional Energy	\$ 0.0486	All Additional Energy	\$ 0.0500
Demand Charge:		Demand Charge:	
First 8 kW of Demand	\$ -	First 8 kW of Demand	\$ -
All Other Demand	\$ 9.00	All Other Demand	\$ 10.00
Revenues From Current Rates	\$ 3,999,060	Revenues From Proposed Rates	\$ 4,247,002
		Change from Current Revenues	6.2%

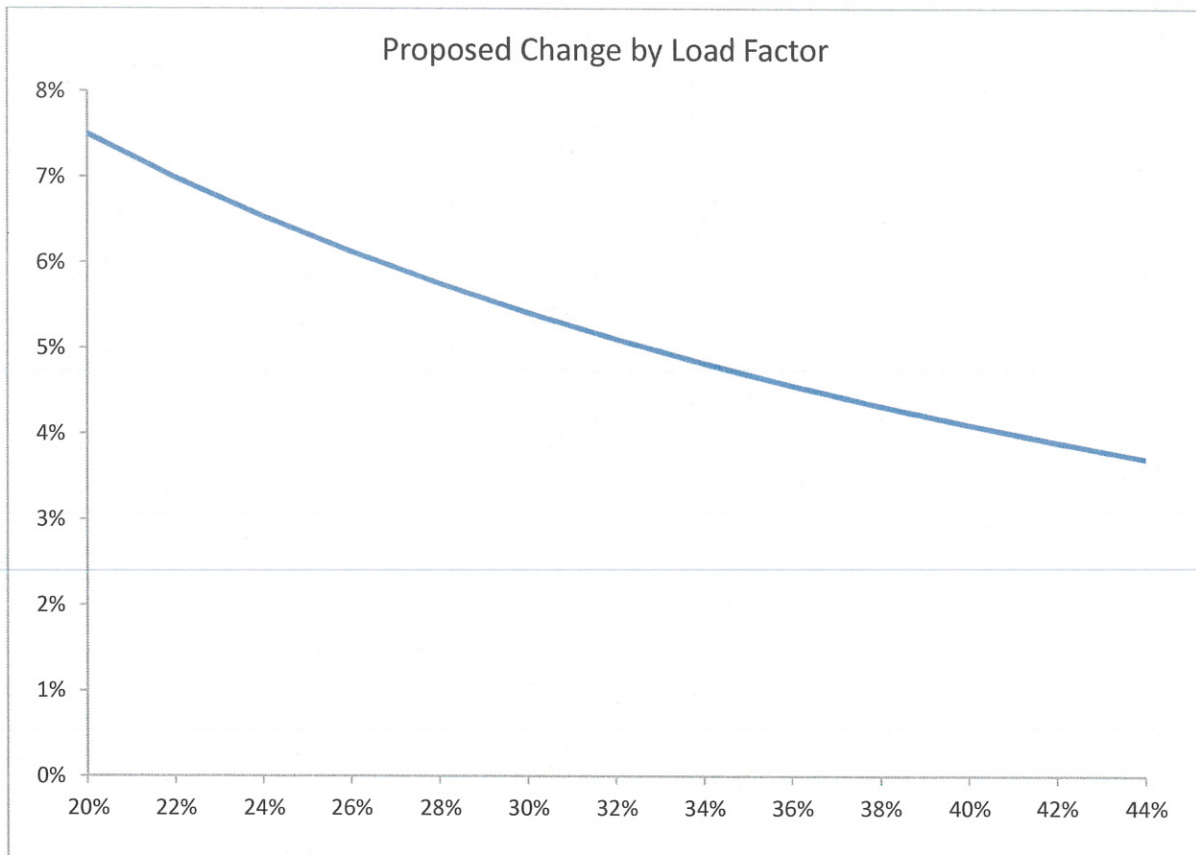


City of Kaysville

Appendix A

Commercial Rate Design Summary (FY2019)

Proposed Rates (FY2018)		Proposed Rates (FY2019)	
Monthly Customer Charge:		Monthly Customer Charge:	
Facilities Charge (Single Phase)	\$ 20.00	Facilities Charge (Single Phase)	\$ 30.00
Facilities Charge (Three Phase)	\$ 25.00	Facilities Charge (Three Phase)	\$ 37.50
Energy Charge:		Energy Charge:	
First 1,000 kWh	\$ 0.0859	First 1,000 kWh	\$ 0.0840
Next 9,000 kWh	\$ 0.0655	Next 9,000 kWh	\$ 0.0644
All Additional Energy	\$ 0.0500	All Additional Energy	\$ 0.0525
Demand Charge:		Demand Charge:	
First 8 kW of Demand	\$ -	First 8 kW of Demand	\$ -
All Other Demand	\$ 10.00	All Other Demand	\$ 11.00
Revenues From Current Rates	\$ 4,247,002	Revenues From Proposed Rates	\$ 4,510,316
		Change from Current Revenues	6.2%

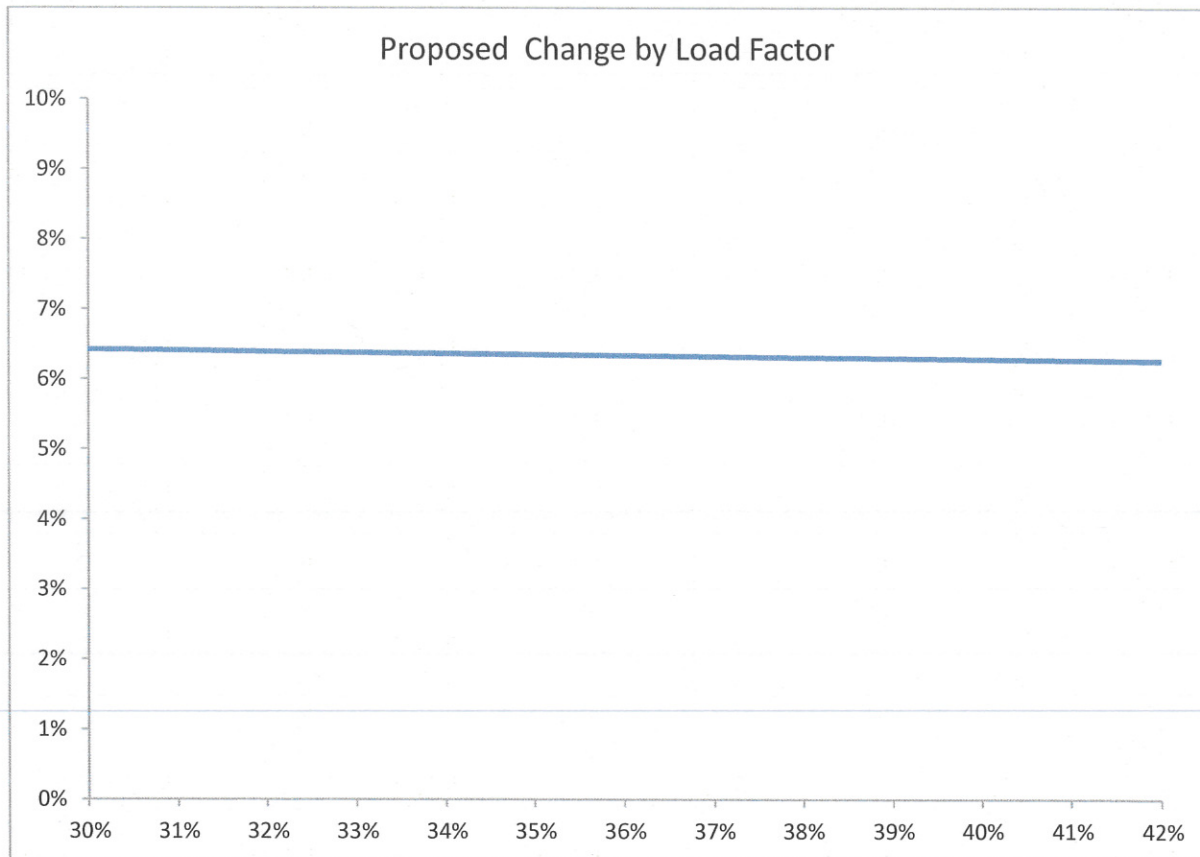


City of Kaysville

Appendix A

Industrial Rate Design Summary (FY2017)

Current Rates		Proposed Rates (FY2017)	
Monthly Customer Charge:		Monthly Customer Charge:	
All Customers	\$ -	All Customers	\$ 50.00
Energy Charge:		Energy Charge:	
All Energy	\$ 0.03829	All Energy	\$ 0.04041
Demand Charge:		Demand Charge:	
All Demand	\$ 7.05	All Demand	\$ 7.50
Revenues From Current Rates	\$ 124,755	Revenues From Proposed Rates	\$ 132,717
		Change from Current Revenues	6.4%



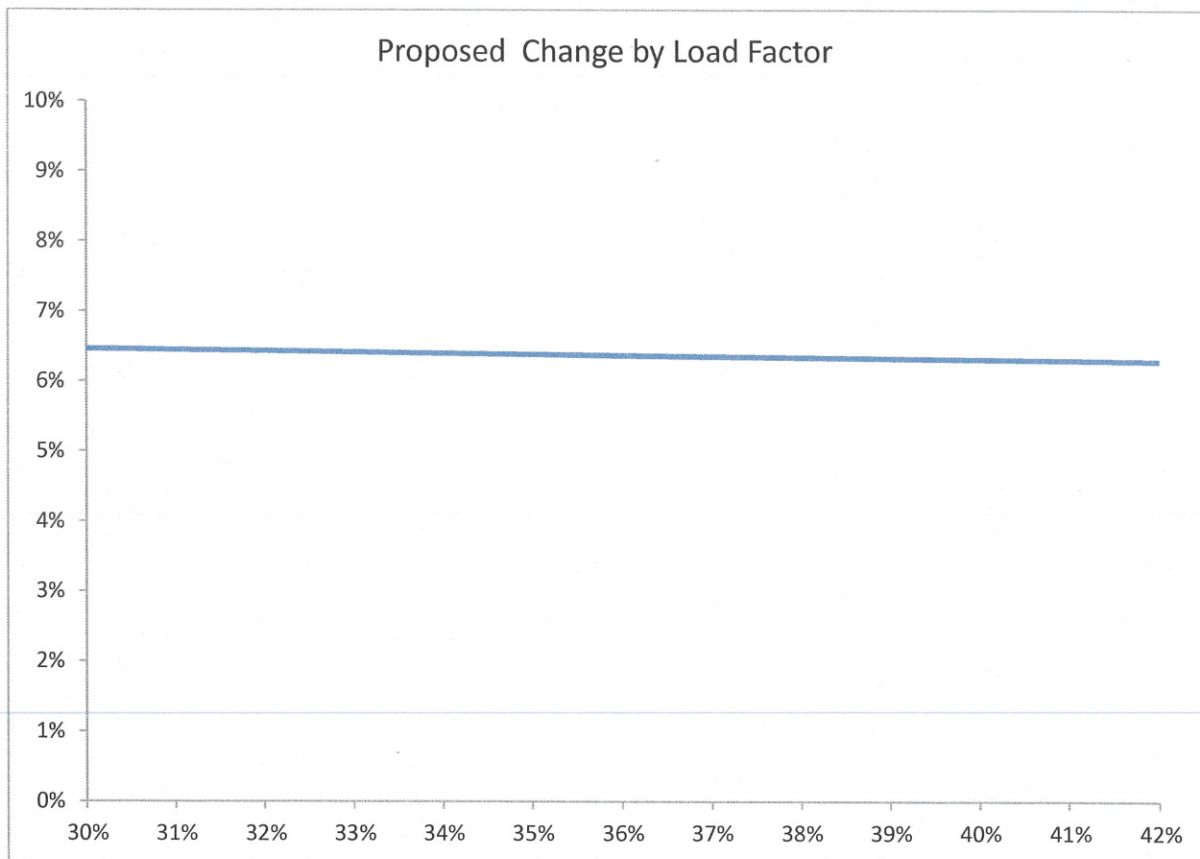
City of Kaysville

Appendix A

Industrial Rate Design Summary (FY2018)

Proposed Rates (FY2017)		
Monthly Customer Charge:		
All Customers	\$	50.00
Energy Charge:		
All Energy	\$	0.04041
Demand Charge:		
All Demand	\$	7.50
Revenues From Current Rates	\$	132,717

Proposed Rates (FY2018)		
Monthly Customer Charge:		
All Customers	\$	100.00
Energy Charge:		
All Energy	\$	0.04262
Demand Charge:		
All Demand	\$	8.00
Revenues From Proposed Rates	\$	141,235
Change from Current Revenues		6.4%

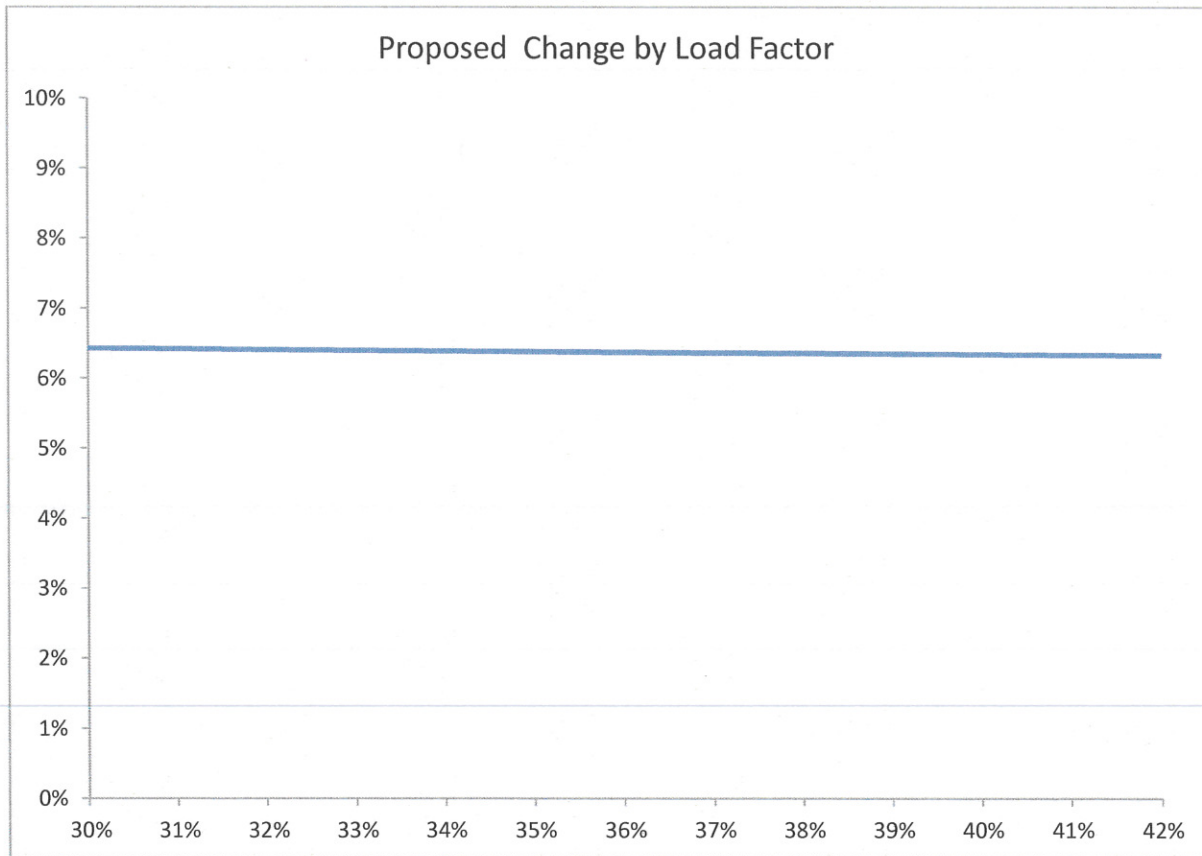


City of Kaysville

Appendix A

Industrial Rate Design Summary (FY2019)

Proposed Rates (FY2018)		Proposed Rates (FY2019)	
Monthly Customer Charge:		Monthly Customer Charge:	
All Customers	\$ 100.00	All Customers	\$ 150.00
Energy Charge:		Energy Charge:	
All Energy	\$ 0.04262	All Energy	\$ 0.04511
Demand Charge:		Demand Charge:	
All Demand	\$ 8.00	All Demand	\$ 8.50
Revenues From Current Rates	\$ 141,235	Revenues From Proposed Rates	\$ 150,274
		Change from Current Revenues	6.4%



Mission Statement

Kaysville City Power and Light mission is to provide reliable electricity with superior customer service at a competitive price to the residents and businesses in Kaysville City.

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[Historical Code](#)

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[Index](#) [Utah Code](#)

[Title 10](#) [Utah Municipal Code](#)

[Chapter 19](#) [Municipal Electric Utility Carbon Emission Reduction Act](#)

[Part 2](#) [Renewable Energy Provisions](#)

[Section 201](#) [Target amount of qualifying electricity -- Renewable energy certificate -- Cost-effectiveness.](#)

10-19-201. Target amount of qualifying electricity -- Renewable energy certificate -- Cost-effectiveness.

- (1) (a) To the extent that it is cost-effective to do so, beginning in 2025 the annual retail electric sales in this state of each municipal electric utility shall consist of qualifying electricity or renewable energy certificates in an amount equal to at least 20% of adjusted retail electric sales.
- (b) The amount under Subsection (1)(a) is computed based upon adjusted retail sales for the calendar year commencing 36 months before the first day of the year for which the target calculated under Subsection (1)(a) applies.
- (c) Notwithstanding Subsections (1)(a) and (b) an increase in the annual target from one year to the next is limited to the greater of:
- (i) 17,500 megawatt-hours; or
 - (ii) 20% of the prior year's amount under Subsections (1)(a) and (b).
- (2) Cost-effectiveness under Subsection (1) is determined using any criteria applicable to the municipal electric utility's acquisition of a significant energy resource established by the municipality's legislative body.
- (3) This section does not require a municipal electric utility to:
- (a) substitute qualifying electricity for electricity from a generation source owned or contractually committed, or from a contractual commitment for a power purchase;
 - (b) enter into any additional electric sales commitment or any other arrangement for the sale or other disposition of electricity that is not already, or would not be, entered into by the municipal electric utility; or
 - (c) acquire qualifying electricity in excess of its adjusted retail electric sales.
- (4) A municipal electrical corporation may combine the following to meet Subsection (1):
- (a) qualifying electricity from a renewable energy source owned by the municipal electric utility;
 - (b) qualifying electricity acquired by the municipal electric utility through trade, power purchase, or other transfer; and
 - (c) a bundled or unbundled renewable energy certificate, including a banked renewable energy certificate.
- (5) To meet Subsection (1), a municipal electric utility may also count:
- (a) qualifying electricity generated or acquired or renewable energy certificates acquired for a program permitting the municipal electric utility's customers to voluntarily contribute to a renewable energy source; and
 - (b) electricity allocated to this state that is produced by a hydroelectric facility becoming operational after December 31, 2007 if the hydroelectric facility is located in any state in which the municipal electric utility, or the interlocal entity with which the municipal electric utility has a contract, provides electric service.

ST. George

Appendix 1

If, in a given monthly billing period, a Customer supplies more electricity to the electric distribution system than SGESD delivers to the Customer, the City will credit the customer for the excess by reducing the Customer's bill for the next monthly billing period.

If a Customer has a kWh credit in the December billing cycle, the City will issue a credit to the Customer account for the kWh credit at the Renewable Power Rate Available. As of July 1, 2015 that rate is \$.04019 per kWh.

Renewable Power Rate Available

As of April 2015, the current average price of energy delivered for our renewables is \$.04019/kWh.

The renewable power rate was calculated from the weighted average cost of power from the hydro facilities from which SGESD receives energy. Additionally, the rate includes the cost of transmission and for scheduling and reserves.

Weighted Average Cost of Renewable Power/kWh	\$	.03308
Current Transmission/kWh	\$	.00544
Current Scheduling and Reserves Rate/kWh	\$	.00167
Renewable Power Rate	\$	.04019

The renewable power rate will be reviewed and adjusted as needed.

A Solar Reliability Charge (SRC) will be applied to a Customer's energy bill monthly based on the inverter's continuous AC name plate rated kW capacity of the solar PV system installed. This charge reflects the cost of SGESD to provide full service to meet the full demand of net metered customers. The Solar Reliability Charge is calculated by dividing the total operational expenses by the total kWh purchased to determine the per kWh cost. The operational per kWh cost will be reviewed and adjusted as needed.

A minimum SRC will be charged for solar installations less than 4 kW.

A \$5.00 credit for systems 4 kW or more will be credited monthly to offset the customer base charge, recognizing the solar PV generation is a local renewable energy source and service other City of St. George utility customers.

For example, a 4 kW continuous nameplate rated system times 158 (estimated generation per month) equals the total kWh solar generation for a month.

kWh solar generation times kWh operational cost less the \$5 recognition credit equals the SRC.

$$\begin{aligned} &4 * 158 \text{ kWh} = 632 \text{ kWh} \\ &632 * \$0.0219 - \$5.00 = \$8.61 \text{ SRC} \end{aligned}$$

For example the Solar Reliability Charge as of July 1, 2015 is listed below:

kW Size	SRC
One kW	\$ 2.25
Two kW	\$ 2.25
Three kW	\$ 2.25
Four kW	\$ 8.61
Five kW	\$12.07
Six kW	\$15.52
Seven kW	\$18.98
Eight kW	\$22.43
Nine kW	\$25.89
Ten kW	\$29.34

Customer will be responsible to pay all fees at the time the building permit is issued. Fees include the cost for review of the application, verification of install and the cost of the meter.

Level 1	
First Review, One site visit for Utility Verification, processing of Net Meter Agreement	\$245
Bi-Directional Meter Upgrade	\$315
Additional Reviews – Billed per Policy 10.87	

Level 2	
First Review, One site visit for Utility Verification, processing of Net Meter Agreement	\$245
Bi-Directional Meter 3 Phase Meter Upgrade	\$415
Additional Reviews – Billed per Policy 10.87	
Cost of any required studies – Estimate to be provided to customer prior to beginning the study	Billed per estimate

The above fees are collected at the time the application is submitted to the SGESD.

Fees for additional services such as multiple reviews or verifications will be billed to the customer after the renewable net metered system is in service.

Fees for studies deemed necessary in this policy will be in compliance with SGESD billing rates set in Policy 10.87.

Some examples of studies that will be conducted at the expense of the customer are:

- Impact Study Fee as proposed in Level 2
- Studies to evaluate proposed interconnection as discussed in Level 2
- Charge for time for additional reviews beyond the first review
- Charge for time for additional Utility Verification beyond the first site visit to verify the system meets the requirements.

Santa Clara City

"EXHIBIT B"

SOLAR RELIABILITY CHARGE & RENEWABLE POWER RATE

Solar Reliability Charge

The Solar Reliability Charge reflects both the Customer solar PV system inverter's continuous AC name plate rated kW capacity, and the cost per kilowatt-hour (kWh) for Santa Clara City to meet the full power demand of net-metered customers. First, the Customer's estimated monthly kWh solar generation is calculated by multiplying the total kW capacity of the Customer's system times 149 kWh (estimated average solar generation per kW capacity per month in Santa Clara). Second, Santa Clara City Utility determines its cost per kWh by dividing its total operation expense by the total kWh it purchases during a given period. The Customer's Solar Reliability Charge is then calculated by multiplying the Customer's estimated monthly kWh solar generation, times the City's cost per kWh. Both the estimated average solar generation per kW capacity per month for Santa Clara, and Santa Clara's per kWh cost will be reviewed annually and adjusted by the City as needed.

For example only:

kW Size	Monthly kWh * Charge	SRC	<i>To find your SRC charge, take the total kW installed and multiply by 149 kWh, to get your total estimated kWh solar generation per month. Then multiply by the City's per kWh cost of \$0.0272. In this example, the Solar Reliability Charge is \$4.05 per kW capacity.</i>
1 kW	1 * 149 = 149 kWh * \$0.0272 =	\$ 4.05	
2 kW	2 * 149 = 298 kWh * \$0.0272 =	\$ 8.10	
3 kW	3 * 149 = 447 kWh * \$0.0272 =	\$12.15	
4 kW	4 * 149 = 596 kWh * \$0.0272 =	\$16.20	
5 kW	5 * 149 = 745 kWh * \$0.0272 =	\$20.25	
6 kW	6 * 149 = 894 kWh * \$0.0272 =	\$24.30	
7 kW	7 * 149 = 1,043 kWh * \$0.0272 =	\$28.35	
8 kW	8 * 149 = 1,192 kWh * \$0.0272 =	\$32.40	

Renewable Power Rate

The renewable power rate is calculated from the weighted average cost of power Santa Clara City receives from its' energy sources. Additionally, the rate includes the cost of transmission, schedule, and reserves and factors in the Solar Reliability Charge. The renewable power rate will be review annually and adjusted by the City as needed.

Santa Clara's Renewable Power Rate is \$.06 per kWh.

**Kaysville City UT
(Kaysville)
Solar Valuation Study
February 16, 2017**

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Submitted Respectfully by:
Mark Beauchamp, CPA, CMA, MBA
President, Utility Financial Solutions, LLC



KAYSVILLE

Executive Summary – Solar Valuation Study

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Executive Summary – Solar Valuation Study

Introduction

This report was prepared to provide guidance on the valuation of solar generation for Kaysville. UFS used a long-run marginal cost valuation considering a natural gas fired turbine generating unit as the next generation resource. A number of customers are installing solar generation to help off-set the cost of electricity and to produce power from carbon-free sources. The purpose of this report is to identify the value of solar for electricity produced by solar generation resources. The study focused on two solar scenarios: Residential and Commercial roof top solar. (All are assumed to be fixed panel systems with no battery storage)

1. Residential roof top solar
2. Commercial roof top solar

As a result of passage of the Public Utility Regulatory Act passed by Congress in 1978, utilities were required to pay an “avoided cost” value for customer-generated electricity. The value was typically set at the marginal price of fuel and ignored the capacity value the customer sited generation provided. In the 1990’s, many states approved net metering policies for Investor Owned Utilities (IOU’s) which credited the customer’s production at the full retail cost of electricity. The methods used in the past typically did not produce a value of customer installed generation that properly reflect the long-term cost savings of the electric utility.

The following items were considered in determining the value of photo voltaic (PV), (solar).

1. Energy savings – The value of producing a kWh of electricity, the marginal energy costs are based on fuel and variable O&M costs of the generator most likely operating as the next generating unit (For Kaysville a natural gas fired turbine generating unit was used in this analysis.
2. Generation capacity savings - The reductions in capacity provided by the distributed generation. This is determined by the cost of capacity times the distributed generations ability to reduce the peak demands of the Utility.
3. Loss savings – As energy is transmitted over the lines of an electric utility losses occur, placing the generation at the customer site reduces the utilities energy losses.
4. Transmission capacity savings – This is the ability of the distributed generating unit to reduce the cost of transmission to transmit energy from the point of production into the utilities local distribution system.
5. Environmental benefits – Reflect the savings from the reductions in carbon that occurs with solar distributed generation units. Currently this is not a direct cost to Kaysville and was not considered in this analysis.
6. Distribution system:
 - a. Transformers, distribution lines, substations – Investments are made to reflect the peak demands of each customer and savings will occur in the long term if the distributed generation can reduce the required sizing on these facilities.
 - b. Sub-transmission lines and substations – The investments in these facilities are to provide facilities to serve the peak demands of the system. Long term savings will occur if the distributed generation can reduce the impacts on the infrastructure designed to handle the peak demands of the system.

KAYSVILLE

Executive Summary – Solar Valuation Study

Summary Results

A summary of the results are listed in the tables below. Kaysville should consider a credit of 5.546 cents per kWh for solar for residential solar and 5.875 cents per kWh for commercial solar. The commercial class has a usage pattern that more closely matches the system peak loads. As a result, you will see that commercial solar has a higher avoided cost credit than residential solar due to the difference in their energy usage patterns. The detail calculations and assumptions used in the analysis are listed in the subsequent sections of this report. Note: Please see Appendix for load and production characteristics. Solar production peaks and commercial load peaks more closely match. As a result the distribution savings are greater for solar – commercial. **This study was conducted using Kaysville and PacifiCorp peak load data.**

No.	Long Run - Residential
1 Production Capacity Savings	0.01682
2 Energy Savings	0.03225
3 Transmission Savings	0.00538
4 Substation and Sub Transmission	0.00057
5 Distribution Savings	0.00044
Total	0.05546

No.	Long Run - Commercial
1 Production Capacity Savings	0.01682
2 Energy Savings	0.03225
3 Transmission Savings	0.00538
4 Substation and Sub Transmission	0.00057
5 Distribution Savings	0.00372
Total	0.05875

KAYSVILLE

Executive Summary – Solar Valuation Study

Assumptions / Project Approach

The long run marginal cost valuation assumed Kaysville would construct a natural gas fired turbine generating unit. The section that follows details the calculations and assumptions used to determine value of distributed generation. This information is equivalent to next generating facility planned by Kaysville.

A natural gas fired turbine generating unit operates as a base load generating unit and the study used the average all in cost on a per kWh basis. The all in costs used in this analysis was \$1,853/kW.

Transmission

Transmission charges were \$2.73 per kW.

Transmission Charges		
Peak Demand	\$	2.73 kW

Distribution

The following were used to identify the distribution savings for customer installed generation. Certain assumptions were made on a customer peak demand before and after the installation of solar. It was assumed there would be a 7% reduction in a customer's peak demand with the installation of an average solar unit.

Solar					
Distribution Cost	Rate	Factor	Adjusted		Avoided Cost
			Rate		
Distribution	0.00405	93%	0.0038		0.00028
Transformer	0.00230	93%	0.0021		0.00016
Avoided Cost		0.00635			0.00044

KAYSVILLE

Executive Summary – Solar Valuation Study

The solar production was projected from NREL (National Renewable Energy Laboratory) historical irradiance data. The table below identifies the solar production would have an annual capacity factor of 15.91%. The generation was compared with the system data from Kaysville and PacifiCorp to identify the potential reduction in the system peaks. This study used a sample solar install from NREL. The average annual kWh solar production / KW of solar should be consistent across other fixed panel installations in the Kaysville service area. As a result, 1,394 kWh average production can be applied to residential roof top as well as commercial roof top installations.

Table of projected solar production compared with Kaysville system data

2015	Average Snow Days - Salt Lake City							Theoretical Capacity factor	Non Snow Days factor	kWH Produced reduced by Snow Days	Capacity factor reduced by Snow Days
	UT	kW Unit	Days	Hours	kWH						
					Possible k	Produced					
1		8.5	1	31	744	744	73	9.83%	72.58%	53	7.13%
2		6.2	1	28	672	672	92	13.68%	77.86%	72	10.65%
3		4.2	1	31	744	744	123	16.53%	86.45%	106	14.29%
4		2.4	1	30	720	720	137	19.04%	92.00%	126	17.52%
5		0.2	1	31	744	744	169	22.74%	99.35%	168	22.60%
6		0	1	30	720	720	162	22.54%	100.00%	162	22.54%
7		0	1	31	744	744	170	22.85%	100.00%	170	22.85%
8		0	1	31	744	744	164	22.11%	100.00%	164	22.11%
9		0	1	30	720	720	141	19.62%	100.00%	141	19.62%
10		0.9	1	31	744	744	120	16.15%	97.10%	117	15.68%
11		4.2	1	30	720	720	81	11.25%	86.00%	70	9.68%
12		8.2	1	31	744	744	60	8.09%	73.55%	44	5.95%
		34.8		365	8760	8,760	1,493.76	17.05%	90.47%	1,394	15.91%

Solar savings and avoided cost

The solar savings considers savings in production capacity, transmission, energy, substation and sub transmission as well as distribution. This total is divided by the units produced to come up with an avoided cost per kWh. The average annual solar avoided cost is 5.546 cents per kWh for solar for residential solar and 5.875 cents per kWh for commercial solar. The respective avoided cost numbers assume a "buy all sell all" approach to metering and billing. If using a more traditional "net metering" scenario please see "residential net metering scenario" or "net billing scenario" on the following pages.

KAYSVILLE

Executive Summary – Solar Valuation Study

Avoided cost solar residential

Month	Solar - Residential						Avoided Cost per kWh	
	Production Capacity Savings	Transmission Savings	Energy Savings	Substation and Sub Transmission	Distribution Savings	Total Savings		
1	\$ -	\$ 0.01	\$ 1.71	\$ -	\$ 0.02	\$ 1.74	\$	0.03286
2	\$ -	\$ 0.03	\$ 2.31	\$ -	\$ 0.03	\$ 2.37	\$	0.03305
3	\$ -	\$ 0.14	\$ 3.43	\$ -	\$ 0.05	\$ 3.62	\$	0.03405
4	\$ -	\$ 0.35	\$ 4.07	\$ -	\$ 0.06	\$ 4.47	\$	0.03544
5	\$ 2.94	\$ 1.73	\$ 5.42	\$ 0.099379	\$ 0.07	\$ 10.26	\$	0.06104
6	\$ 5.98	\$ 1.59	\$ 5.23	\$ 0.202354	\$ 0.07	\$ 13.07	\$	0.08055
7	\$ 6.79	\$ 1.69	\$ 5.48	\$ 0.230023	\$ 0.07	\$ 14.27	\$	0.08395
8	\$ 5.71	\$ 1.50	\$ 5.30	\$ 0.193156	\$ 0.07	\$ 12.78	\$	0.07769
9	\$ 2.04	\$ 0.33	\$ 4.56	\$ 0.068979	\$ 0.06	\$ 7.06	\$	0.04997
10	\$ -	\$ 0.13	\$ 3.76	\$ -	\$ 0.05	\$ 3.94	\$	0.03379
11	\$ -	\$ -	\$ 2.25	\$ -	\$ 0.03	\$ 2.28	\$	0.03269
12	\$ -	\$ -	\$ 1.43	\$ -	\$ 0.02	\$ 1.45	\$	0.03269
Total	\$ 23.45	\$ 7.50	\$ 44.96	\$ 0.79	\$ 0.61	\$ 77.31	\$	0.05546

Summary avoided cost solar Residential

No.	Long Run - Residential
1	Production Capacity Savings 0.01682
2	Energy Savings 0.03225
3	Transmission Savings 0.00538
4	Substation and Sub Transmission 0.00057
5	Distribution Savings 0.00044
Total	0.05546

KAYSVILLE

Executive Summary – Solar Valuation Study

Avoided cost solar commercial

Solar - Commercial									
Month	Production Capacity Savings	Transmission Savings	Energy Savings	Substation and Sub Transmission	Distribution Savings	Total Savings	Avoided Cost per kWh		
1	\$ -	\$ 0.01	\$ 1.71	\$ -	\$ 0.20	\$ 1.92	\$	0.03614	
2	\$ -	\$ 0.03	\$ 2.31	\$ -	\$ 0.27	\$ 2.60	\$	0.03634	
3	\$ -	\$ 0.14	\$ 3.43	\$ -	\$ 0.40	\$ 3.97	\$	0.03734	
4	\$ -	\$ 0.35	\$ 4.07	\$ -	\$ 0.47	\$ 4.89	\$	0.03873	
5	\$ 2.94	\$ 1.73	\$ 5.42	\$ 0.099379	\$ 0.63	\$ 10.81	\$	0.06432	
6	\$ 5.98	\$ 1.59	\$ 5.23	\$ 0.202354	\$ 0.60	\$ 13.61	\$	0.08384	
7	\$ 6.79	\$ 1.69	\$ 5.48	\$ 0.230023	\$ 0.63	\$ 14.83	\$	0.08723	
8	\$ 5.71	\$ 1.50	\$ 5.30	\$ 0.193156	\$ 0.61	\$ 13.32	\$	0.08098	
9	\$ 2.04	\$ 0.33	\$ 4.56	\$ 0.068979	\$ 0.53	\$ 7.52	\$	0.05325	
10	\$ -	\$ 0.13	\$ 3.76	\$ -	\$ 0.43	\$ 4.33	\$	0.03708	
11	\$ -	\$ -	\$ 2.25	\$ -	\$ 0.26	\$ 2.51	\$	0.03597	
12	\$ -	\$ -	\$ 1.43	\$ -	\$ 0.16	\$ 1.59	\$	0.03597	
Total	\$ 23.45	\$ 7.50	\$ 44.96	\$ 0.79	\$ 5.19	\$ 81.89	\$	0.05875	

Summary avoided cost solar Commercial

No.	Long Run - Commercial	
1	Production Capacity Savings	0.01682
2	Energy Savings	0.03225
3	Transmission Savings	0.00538
4	Substation and Sub Transmission	0.00057
5	Distribution Savings	0.00372
Total		0.05875

KAYSVILLE

Executive Summary – Solar Valuation Study

* Note: The total revenue does not include the customer charge nor does it include PCA. This additional monthly charge per kW of installed solar calculation will need to be updated as the average residential rate changes and / or as the PCA changes.

Residential Net metering scenario

Residential Charge per kW of Solar Installation		
Average Residential Rate *	\$	0.09429
PCA	\$	-
Average Net Rate (Residential and PCA)	\$	0.09429
Avoided Cost Long-Run		0.05546
Lost Revenues per kWh		0.03883
Annual kWh production from 1 kW of Solar		1,394
Annual Under-Recovery from Solar	\$	54.12
Additional Monthly Charge per kW of installed Solar	\$	4.51

* Note: The total revenue does not include the customer charge nor does it include PCA. This additional monthly charge per kW of installed solar calculation will need to be updated as the average commercial ("all other than residential") rate changes and / or as the PCA changes.

Commercial Net metering scenario

Commercial Charge per kW of Solar Installation		
Average Commercial Rate *	\$	0.10084
PCA	\$	-
Average Net Rate (Commercial and PCA)	\$	0.10084
Avoided Cost Long-Run		0.05875
Lost Revenues per kWh		0.04209
Annual kWh production from 1 kW of Solar		1,394
Annual Under-Recovery from Solar	\$	58.67
Additional Monthly Charge per kW of installed Solar	\$	4.89

KAYSVILLE

Executive Summary – Solar Valuation Study

Recommendations

1. Kaysville should apply the following values in the determination of rate impacts to customers.
 - Buy all sell all options**
 - a. Residential roof top solar - 5.546 cents per kWh
 - b. Commercial roof top solar - 5.875 cents per kWh
 - Net metering options**
 - c. Residential net metering scenario - \$4.51 additional monthly charge per kW of installed solar
 - d. Commercial net metering scenario - \$4.89 additional monthly charge per kW of installed solar
 - Net billing options**
 - e. Residential roof top solar - 5.546 cents per kWh
 - f. Commercial roof top solar - 5.875 cents per kWh
2. The analysis is based on long-run marginal costs (avoided cost) and load profile data from the renewable units compared with the total system load profile. Both the load profile and long-run marginal costs will change over time and Kaysville should consider reviewing the kWh values periodically.

Metering and billing options defined

Buy all sell all

Under a buy all sell all metering and billing scenario two meters will be required. All power used by the customer will be supplied by the utility. This utility supplied power will be metered and billed at the current normal utility rates. The solar production will be metered by the second meter. All solar production will be sent back to the utility grid and credited at the current avoided cost. This option is typically recommended for community solar projects. This option is occasionally used for larger commercial customers. This option is typically not used for residential roof top solar.

Buy all sell all summary

Metering: Two meters are required with a buy all sell all scenario. One meter is for power supplied by the utility to the customer. A second meter is used for solar production sent back to the utility by the customer.

Solar Production: All solar production gets sent back to the utility. The customer only uses power supplied by the utility.

Billing: The utility sells all the power to the customer at the normal rate. The utility buys all of the solar production at the avoided cost. (A and B above)

Metering and billing options defined

Net metering

Under a net metering scenario only one meter will be required. Net metering can be done under two different metering options. The first option is a meter that “spins both ways”. This type of meter will spin forward when power is being used from the utility. This meter will then spin in reverse when excess solar production is being sent back to the utility. The second option is a meter that tracks the “in and out” separately. The utility supplied power in will be tracked and the solar production excess sent back to the utility is tracked separately. These two numbers can be netted for billing at the current normal utility rates. Under both metering options under net metering the customer bill will be the same. At the end of the billing cycle the net usage will be billed at the current normal utility rates. If there is a billing cycle that there is more power sent back to the utility than power supplied by the utility the excess solar production will be credited at the current normal utility rates. The customer is charged an additional monthly charge per kW of installed solar. This option is generally used for commercial and residential roof top solar customers. Some utilities will limit the dollar amount and/or number of months that an over production of solar will be allowed to be credited.

Net metering summary

Metering: Only one meter is required with a net metering scenario. One meter is for power supplied by the utility to the customer. The same meter is used for solar production sent back to the utility by the customer. The two most typical single net meter options are a meter that spins both ways or a meter that tracks the in and out separately. Both meters should allow for the same customer bill to be calculated.

Solar Production: Only excess solar production gets sent back to the utility. The customer only uses power supplied by the utility when solar production does not meet their usage needs.

Billing: The utility sells all the power to the customer at the normal rate. The utility buys the excess solar production at the normal rate. (Net usage based on two metering options above) The customer is credited at normal rates if more solar production is sent to the utility then used from the utility. The customer is charged an additional monthly charge per kW of installed solar. (C and D above)

Metering and billing options defined

Net billing

Under a net billing scenario only one meter will be required. Net billing is typically done when the utility only has meters that spin both ways. Net billing can also be an option for customers on demand and / or demand time-of-use rates. At the end of the billing cycle the net usage will be billed at the current normal utility rates. If there is a billing cycle that there is more power sent back to the utility than power supplied by the utility the excess solar production will be credited at the current avoided cost. This option is generally used for commercial and residential roof top solar customers. Some utilities will limit the dollar amount and/or number of months that an over production of solar will be allowed to be credited.

Net billing summary

Metering: Only one meter is required with a net billing scenario. One meter is for power supplied by the utility to the customer. The same meter is used for solar production sent back to the utility by the customer. This typical single net meter option is a meter that spins both ways.

Solar Production: Only excess solar production gets sent back to the utility. The customer only uses power supplied by the utility when solar production does not meet their usage needs.

Billing: The utility sells all the power to the customer at the normal rate. The utility buys the excess solar production at the avoided cost. This only happens when there is a billing cycle that there is more power sent back to the utility than power supplied by the utility. (E and F above)

KAYSVILLE

Executive Summary – Solar Valuation Study

Appendix of Load Characteristics

The charts below are summaries of the load profiles used for the system load and solar generation. **This study was conducted using Kaysville load data for solar valuation and PacifiCorp load data for transmission solar valuation.**

System load profile comparing the MWH, peak demand of system, date and time of system peaks.

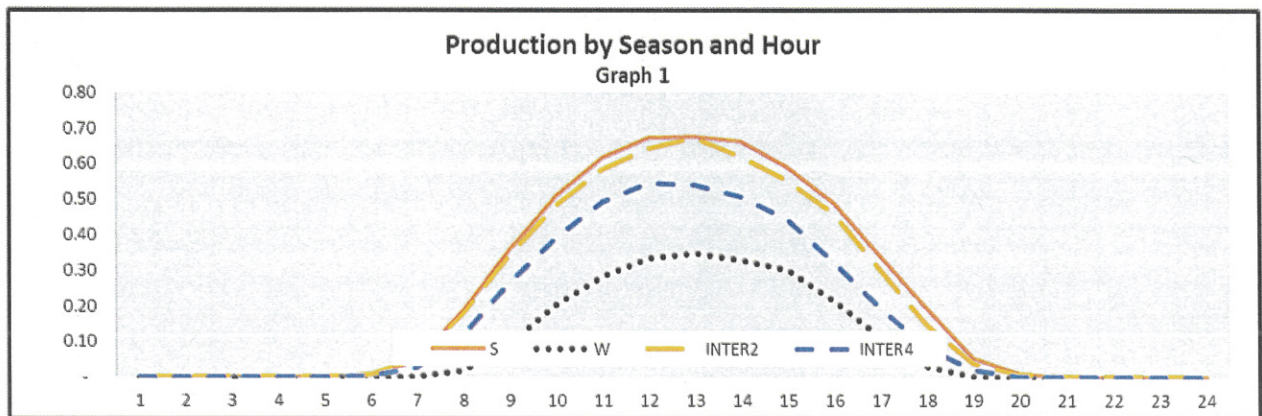
System Load (2013-2016)									
Month	Assigned Season	MWhs in Month	Peak Demand Month (MW)	Days in Month	Hours in Month	Monthly Load Factor	System Peak Hour	System Peak Date	System Peak Day
January	W	12,128	22.76	31	744	72%	19	1/7/2013	Monday
February	W	10,056	20.63	28	672	73%	19	2/4/2013	Monday
March	W	10,081	18.88	31	744	72%	21	3/4/2013	Monday
April	INTER4	9,599	18.00	30	720	74%	22	4/29/2013	Monday
May	INTER4	10,847	24.97	31	744	58%	18	5/27/2013	Monday
June	INTER2	14,845	39.70	30	720	52%	18	6/26/2013	Wednesday
July	S	17,324	40.54	31	744	57%	18	7/1/2013	Monday
August	S	15,929	39.54	31	744	54%	18	8/5/2013	Monday
September	INTER2	11,988	30.35	30	720	55%	18	9/17/2013	Tuesday
October	INTER4	10,309	19.66	31	744	70%	21	10/1/2013	Tuesday
November	INTER4	10,820	23.40	30	720	64%	19	11/25/2013	Monday
December	W	12,972	25.74	31	744	68%	19	12/9/2013	Monday
TOTAL		146,897	324	365	8,760				

KAYSVILLE

Executive Summary – Solar Valuation Study

Appendix of Production Characteristics

Projected Solar Production Characteristics (from NREL)



NREL Solar Production Fixed Open Rack

Demand Peak Summary

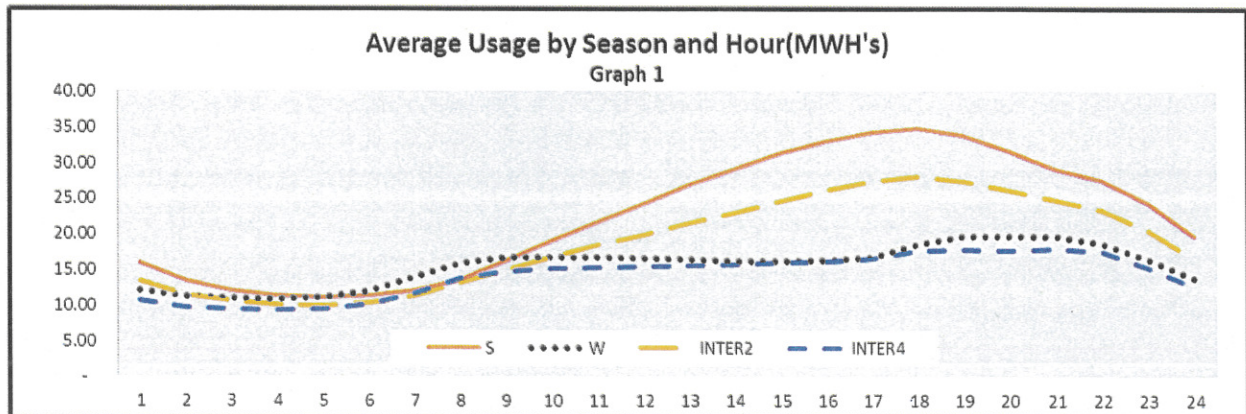
Month	Peak	Peak Hour	Peak Date
January	0.47	13	1/10/2015
February	0.64	14	2/27/2015
March	0.73	12	3/30/2015
April	0.79	13	4/30/2015
May	0.85	13	5/24/2015
June	0.86	12	6/6/2015
July	0.80	14	7/12/2015
August	0.80	13	8/28/2015
September	0.80	13	9/8/2015
October	0.73	12	10/15/2015
November	0.56	13	11/1/2015
December	0.45	13	12/26/2015

KAYSVILLE

Executive Summary – Solar Valuation Study

Appendix of Load Characteristics

Historical Kaysville System Load Characteristics (2013-2016)



System Load Peaks

Demand Peak Summary

Month	Peak	Peak Hour	Peak Date
January	22.76	19	1/7/2015
February	20.63	19	2/4/2015
March	18.88	21	3/4/2015
April	18.00	22	4/29/2015
May	24.97	18	5/27/2015
June	39.70	18	6/26/2015
July	40.54	18	7/1/2015
August	39.54	18	8/5/2015
September	30.35	18	9/17/2015
October	19.66	21	10/1/2015
November	23.40	19	11/25/2015
December	25.74	19	12/9/2015

KAYSVILLE

Executive Summary – Solar Valuation Study

Utility Financial Solutions, LLC
185 Sun Meadow Ct.
Holland, MI 49424
Phone: 616-393-9722
Fax: 616-393-9721

ACCOUNTANTS' COMPILATION REPORT

Kaysville City UT
Board of Directors

The purpose of this report is to assist management in determining the value of solar. This report should not be used for any other purpose.

The accompanying solar valuation study for the Kaysville Electric Department was compiled with load data from Kaysville and PacifiCorp. Since Kaysville had no solar production data, data anticipated to be similar to Kaysville was used. Solar production data used was from NREL (National Renewable Energy Laboratory). Weather data for monthly snow days was used from www.currentresults.com.

Differences between historical (NREL production data used) and actual Kaysville results will occur since some assumptions may not materialize and events and circumstances may occur that were not anticipated. Some of these variations may be material. Utility Financial Solutions, LLC has no responsibility to update this report after the date of this report. However, it is recommended that Kaysville update this study as base assumptions used materially change.

This report is intended for information and use by management and the Board of Directors for the purposes stated above. This report is not intended to be used by anyone except the specified parties.

UTILITY FINANCIAL SOLUTIONS, LLC

Mark Beauchamp, CPA, CMA, MBA
February 16, 2017

KAYSVILLE CITY
STATEMENT OF NET POSITION
PROPRIETARY FUNDS - BUSINESS-TYPE ACTIVITIES
JUNE 30, 2016

	Water	Sewer
ASSETS		
Current Assets:		
Cash	\$ 2,259,168	\$ 755,625
Accounts Receivable (Net of Allowance for Uncollectibles)	256,313	196,954
Inventory	259,000	-
Total Current Assets	2,774,481	952,579
Noncurrent Assets		
Capital Assets:		
Land	120,094	-
Net Depreciable Capital Assets	15,251,829	20,644
Water Stock	460,140	-
Net Pension Asset	234	-
Total Noncurrent Assets	15,832,297	20,644
Total Assets	18,606,778	973,223
DEFERRED OUTFLOWS OF RESOURCES		
Deferred Outflows Related to Pensions	92,696	-
Total Deferred Outflows of Resources	92,696	-
LIABILITIES		
Current Liabilities:		
Accounts Payable	17,725	206,965
Due to Other Fund	-	-
Deposits	19,331	-
Interest Accrued	-	-
Noncurrent Liabilities Due Within One Year	9,120	-
Total Current Liabilities	46,176	206,965
Noncurrent Liabilities		
Due In More Than One Year	36,480	-
Net Pension Liability	182,777	-
Total Noncurrent Liabilities	219,257	-
Total Liabilities	265,433	206,965
DEFERRED INFLOWS OF RESOURCES		
Deferred Inflows Related to Pensions	23,776	-
Total Deferred Inflows of Resources	23,776	-
NET POSITION		
Net Investment in Capital Assets	15,786,463	20,644
Restricted for:		
Impact Fees	314,393	-
Unrestricted	2,309,409	745,614
Total Net Position	\$ 18,410,265	\$ 766,258

The notes to the financial statements are an integral part of this statement.

	Electric	Storm Water	Pressure Irrigation	Sanitation	Ambulance	Total

KAYSVILLE CITY
STATEMENT OF REVENUES, EXPENSES AND CHANGES IN NET POSITION
PROPRIETARY FUNDS - BUSINESS-TYPE ACTIVITIES
YEAR ENDED JUNE 30, 2016

	Water	Sewer
Operating Revenues:		
Charges for Services (Net of uncollectibles)	\$ 2,710,382	\$ 2,172,141
Charges for Services (Reciprocal)	-	-
Charges for Services (Non-Reciprocal)	36,257	4,884
Total Operating Revenues	2,746,639	2,177,025
Operating Expenses:		
Personnel Services	591,585	15,944
Contractual Services	54,812	-
Administrative Charges from General Fund	150,000	62,000
Interfund Services	85,000	-
Purchases Water/Treatment/Power/Refuse	467,885	2,059,070
Supplies, Maintenance, and Miscellaneous Operating	483,087	57,637
Energy Sales and Use Tax Charge	-	-
Depreciation	539,397	688
Total Operating Expenses	2,371,766	2,195,339
Operating Income (Loss)	374,873	(18,314)
Nonoperating Revenues (Expenses):		
Connection Fees	66,555	-
Extension Fees	-	-
Impact Fees	184,692	-
Interest Income	5,595	2,382
Miscellaneous	1,839	-
Interest Expense	-	-
Total Nonoperating Revenues (Expenses)	258,681	2,382
Income (Loss) Before Contributions and Transfers	633,554	(15,932)
Contributions From Developers	671,620	-
Transfers In (Out):		
General Fund	-	-
Non-Reciprocal Utility Services	(36,257)	(4,884)
Change in Net Position	1,268,917	(20,816)
Net Position - Beginning	17,141,348	787,074
Net Position - Ending	\$ 18,410,265	\$ 766,258

The notes to the financial statements are an integral part of this statement.

Electric	Storm Water	Pressure Irrigation	Sanitation	Ambulance	Total
\$ 13,751,665	\$ 1,102,544	\$ 1,187,426	\$ 1,840,078	\$ 413,301	\$ 23,177,537
203,707	-	-	-	-	203,707
-	26,643	-	11,580	-	79,364
13,955,372	1,129,187	1,187,426	1,851,658	413,301	23,460,608
1,477,007	306,900	2,302	24,695	403,037	2,821,470
514,223	101,466	-	4,791	68,157	743,449
180,000	60,000	60,000	90,000	-	602,000
150,000	59,000	-	5,000	6,800	305,800
8,905,687	-	1,146,724	1,613,586	-	14,192,952
358,252	308,909	2,968	16,157	51,925	1,278,935
760,201	-	-	-	-	760,201
919,319	772,845	-	102,772	6,291	2,341,312
13,264,689	1,609,120	1,211,994	1,857,001	536,210	23,046,119
690,683	(479,933)	(24,568)	(5,343)	(122,909)	414,489
128,301	-	-	-	-	194,856
476,810	-	-	-	-	476,810
278,111	-	-	-	-	462,803
21,239	3,976	446	2,976	119	36,733
14,732	-	-	-	-	16,571
(669)	(1,571)	-	(2,481)	(5,545)	(10,266)
918,524	2,405	446	495	(5,426)	1,177,507
1,609,207	(477,528)	(24,122)	(4,848)	(128,335)	1,591,996
-	1,284,449	-	-	-	1,956,069
-	-	-	-	125,000	125,000
-	(26,643)	-	(11,580)	-	(79,364)
1,609,207	780,278	(24,122)	(16,428)	(3,335)	3,593,701
23,822,089	12,199,321	3,884,078	1,407,454	464,365	59,705,729
\$ 25,431,296	\$ 12,979,599	\$ 3,859,956	\$ 1,391,026	\$ 461,030	\$ 63,299,430

KAYSVILLE CITY
STATEMENT OF CASH FLOWS
PROPRIETARY FUNDS - BUSINESS-TYPE ACTIVITIES
YEAR ENDED JUNE 30, 2016

	Water	Sewer
CASH FLOWS FROM OPERATING ACTIVITIES:		
Cash Received from Customers	\$ 2,661,093	\$ 2,149,800
Cash Payments to Suppliers for Goods and Services	(971,807)	(2,097,339)
Cash Payments to Employees for Services	(599,124)	(15,944)
Cash Payments for Interfund Services	(235,000)	(62,000)
Net Cash Provided (Used) by Operating Activities	855,162	(25,483)
CASH FLOWS FROM NON-CAPITAL FINANCING ACTIVITIES:		
Transfers from (to) Other Funds	-	-
Net Cash Provided (Used in) Non-Capital Financing Activities	-	-
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES:		
Impact, Extension and Connection Fees	253,086	-
Acquisition of Capital Assets	(171,368)	-
Principal Paid on Bonds and Notes	-	-
Proceeds from Bonds and Notes	-	-
Interest Paid	-	-
Net Cash Provided (Used) by Capital and Related Financing Activities	81,718	-
CASH FLOWS FROM INVESTING ACTIVITIES:		
Interest Received	5,595	2,382
Net Cash Provided from Investing Activities	5,595	2,382
Net Increase (Decrease) in Cash and Cash Equivalents	942,475	(23,101)
Cash/Equivalents at Beginning of Year	1,316,693	778,726
Cash/Equivalents at End of Year	\$ 2,259,168	\$ 755,625
Reconciliation of Operating Income (Loss) to Net Cash Provided by Operating Activities		
Operating Income (Loss)	\$ 374,873	\$ (18,314)
Reconciling Adjustments:		
Depreciation	539,397	688
Calculated Pension	(5,653)	-
Non-Reciprocal Utility Services	(36,257)	(4,884)
Changes in Assets and Liabilities:		
Changes in Receivables	(46,989)	(22,341)
Changes in Inventory	51,000	-
Changes in Accounts Payable	(17,023)	19,368
Changes in Deposits	(2,300)	-
Changes in Compensated Absences	(1,866)	-
Total Adjustments	480,289	(7,169)
Net Cash Provided by Operating Activities	\$ 855,162	\$ (25,483)
Noncash investing and capital activities:		
Contributions from Developers	\$671,620	-

The notes to the financial statements are an integral part of this statement.

	Electric	Storm Water	Pressure Irrigation	Sanitation	Ambulance	Total
\$	13,722,046	\$ 1,102,304	\$ 1,184,339	\$ 1,836,848	\$ 422,541	\$ 23,078,971
	(11,397,393)	(412,344)	(1,106,254)	(1,548,903)	(169,416)	(17,703,456)
	(1,486,752)	(300,283)	(2,302)	(24,695)	(403,037)	(2,832,137)
	(330,000)	(119,000)	(60,000)	(95,000)	(6,800)	(907,800)
	507,901	270,677	15,783	168,250	(156,712)	1,635,578
	-	-	-	-	125,000	125,000
	-	-	-	-	125,000	125,000
	897,954	-	-	-	-	1,151,040
	(1,007,098)	(164,311)	-	(42,186)	(419,500)	(1,804,463)
	(44,118)	(44,518)	-	(46,742)	(84,939)	(220,317)
	(802)	(2,047)	-	(2,732)	424,500	424,500
	(154,064)	(210,876)	-	(91,660)	(3,320)	(8,901)
					(83,259)	(458,141)
	21,239	3,976	446	2,976	119	36,733
	21,239	3,976	446	2,976	119	36,733
	375,076	63,777	16,229	79,566	(114,852)	1,339,170
	6,739,778	1,281,822	144,191	934,874	201,058	11,397,142
\$	7,114,854	\$ 1,345,599	\$ 160,420	\$ 1,014,440	\$ 86,206	\$ 12,736,312
\$	690,683	\$ (479,933)	\$ (24,568)	\$ (5,343)	\$ (122,909)	\$ 414,489
	919,319	772,845	-	102,772	6,291	2,341,312
	(15,704)	(2,514)	-	-	-	(23,871)
	-	(26,643)	-	(11,580)	-	(79,364)
	(235,476)	(240)	(3,087)	(3,230)	9,240	(302,123)
	(108,800)	-	-	-	-	(57,800)
	(750,230)	(1,969)	43,438	85,631	(49,334)	(670,119)
	2,150	-	-	-	-	(150)
	5,959	9,131	-	-	-	13,204
	(182,782)	750,610	40,351	173,593	(33,803)	1,221,089
\$	507,901	\$ 270,677	\$ 15,783	\$ 168,250	\$ (156,712)	\$ 1,635,578



1

POWER COMMISSION BOARD MEETING

Meeting Minutes February 7, 2017

Minutes of the Kaysville Power Commission Board meeting held Tuesday, February 7, 2017 at 7:00 P.M. in the City Council Chambers of the Kaysville City Municipal Center at 23 East Center St. Kaysville, Utah 84037.

Present: Mayor Steve Hiatt, Council Member Susan Lee, Board Member Sean Chilcote, Board Member Alan Farnes, Board Member Patrick Hein, Board Member John Loveless, Board Member Jordan Stephenson, Board Member Brok Thayn.

Others present: City Manager Shayne Scott, Power Superintendent Gary Hatch, Resource and Service Manager Bruce Rigby, Administrative Assistant Stacie Harward, City Recorder Maria Devereux, Greg Lewis, Tanalie Hein.

Opening Provided by Council Member Lee.

Board Member Patrick Hein needed to be excused at 7:25 for a few minutes for a family matter

Prayer Given by Sean Chilcote.

APPROVAL OF MINUTES

No minutes to approve

Council Member Lee recommended that everyone in attendance publically state their names.

Mayor Steve Hiatt was in attendance and asked if he could say a few words. He welcomed all to the board and thanked them for their willingness to serve on the board.

SELECTION OF OFFICERS

Council Member Lee recommended that this item either be postponed for another meeting or maybe wait until the end of the meeting before a selection is made. The board members decided to wait until the end of the meeting to make the selections of officers. The Chairman will be responsible for the conduct of the meeting. A Chairman and a Vice Chairman will need to be chosen. Duties will include the direction of the meeting following the agenda.

REGULAR MEETING DAY AND TIME

Council Member Lee proposed that the meeting be held the first Tuesday of the Month at 7:00 PM. Everyone agreed that the time and date proposed would be the best option.

MEMBER COMPENSATION

Council Member Lee turned this agenda item over to the City Manager Shane Scott. City Manager Scott stated that the city ordinance will be set by resolution of \$50.00 dollars per meeting. This compensation will need to be approved by the City Council. It was recommended that the compensation be in line with the other commissions in the city (Planning Commission). Council Member Lee had also been informed that other Power Commission Boards in other cities have paid for the board to attend the UAMPS Power Retreat that takes place once a year. That Recommendation was put on hold and tabled for another time to discuss.

It was recommended that the meetings be only 2 hours or less.

Board Member Loveless made a motion to approve the Member compensation and follow the guidelines of the other commissions involved within the city of \$50.00 dollars per meeting, second by Board Member Sean Chilcote.

EXPLANATION OF STAGGERED TERMS

City Manager Scott explained to the Commission that there is a concern with everyone starting at the same time. He described how this would lead to everyone's terms of service expiring at the same time. The decision was made that the terms of service will be as follows.. Three (3) members will be assigned for Two (2) years of service and Three (3) members will be assigned to Four (4) years of service. City Manager Scott will make the selection and will inform the members of their particular terms.

CONFLICTS OF INTEREST

City Manager Shayne Scott explained to the Board Members that they need to be aware of the importance in Government Transparency. Board Members need to be aware of their potential conflicts of interest and keep the best interests of the City in mind when it comes to conflict of interest. Remember to keep things transparent.

ORGANIZATIONAL SETUP OF POWER DEPARTMENT

Power Superintendent Gary Hatch presented how the Power Department is set up.

There is 15 employees at this time employed by the Power Department.

Power Superintendent- Gary Hatch

Resource and Service Manager – Bruce Rigby

Operations Supervisor- Brett Thomas

Administrative Assistant – Stacie Harward

Lead Lineman-Brandon Child

Lead Lineman-Danny Black

Lead Lineman-Tyler Parkin

Journeyman- Steve Rice
Journeyman-Wesley Jones
Journeyman-Josh Ferrin
Lineman Apprentice-Brian Johnson-4th Year
Lineman Apprentice-Garrett Millward-2nd Year
Lineman Apprentice-Chris Banz-1st Year

Meter Reader- Jeff Fillin
Blue Stakes- Marty Willey

Council Member Lee asked if they have any questions or concerns who should they contact?
Power Superintendent Gary Hatch recommended questions be directed to him and he will either answer the question or refer it to Resource and Service Manager Bruce Rigby.

On call/standby list will be provided to the Board Members.

Resource and Service Manager Bruce Rigby provided the following information (Approximate Figures) to the Board Members.

Residential Customers – 8400 (changes on a daily basis)
Commercial Meters- 800 (Single Phases and Three Phases)
Industrial Meters-1 (LDS Church Mill)
Exact Numbers will be provided in the next meeting.
46 Megawatts is the peak demand. This happened in the summer of 2016.

Board Member Thayn stated he would like to know more in depth information about hourly data.

SOLAR DISCUSSION

Councilman Lee wanted the board to be aware that the City Council will be relying heavily on the Board's recommendations and expertise in this matter. City Manager Scott started the discussion with the Net Metering Program. This has been a major topic and there have been many discussions among the City Council over the last couple of years. A Net Metering program has been established between the City and the Solar Power user. A moratorium has also been discussed but not put in place by the City Council as an alternative until the matter can be resolved. They are looking for recommendations on the best way to handle the roof top solar user and the impact it will have on the non-solar user customer. The City Council is looking for recommendations on how to proceed with this program. What will be in the best interest of the City and the residents involved in the program. City Manager Scott stated that the City Council is very aware of the importance of the Solar Power Issue and is looking for guidance in this matter. The City Council is aware of the checks and balances that comes with this issue. He understands that there will not be a resolution in this matter during this meeting but that it will start a discussion. He pointed out that Rocky Mountain Power has requested from the Public Service Commission a decision about the Solar Power Issue. Their decision is expected in August and are hoping that their decision will be well received. He feels that we should not base our decision on what other cities or organizations have decided but it is something to take in consideration. Bruce Rigby pointed out

that a study had been conducted on this matter for Kaysville City Power and Light. The Board Members have been given a copy of that Study. The Report included the final cost alternatives, It also addresses the questions of What the Solar Companies want, What the City wants, and What is basically the middle of the road. It comes down to how much is the city willing to subsidize the Solar Power Customer. The company that provided the information for this study has done 1000's of these studies throughout the country. They were asked to compile a list of questions that they might have. The individual that compiled the report would be willing to call in with a conference call and answer any questions that they might have.

It was pointed out that other cities with Power Utilities are waiting for us to make a decision. We are possibly setting a precedent in this matter.

Board Member Thayn wanted to know if the study provided the number of solar customers we have on our system. Bruce Rigby was able to provide the following information. As of the day of this meeting we had 132 customers, mostly residential. We have One (1) Elementary School that has been on the system for 3 months with a 265 KW PV System, Davis Applied Technology College with a 60 KW PV System and the Utah State Botanical Gardens with a small system. Board Member Farnes asked if we have limitations to our city billing software. Bruce Rigby indicated that the Net Metering figures are at the moment being hand entered by Holly Henderson in our billing department. Bills are being hand calculated at the moment due to the billing software cannot handle the reverse readings.

Board Member Thayn wanted to know what the Mission Statement and main goal of the Power Company is for our customers. Bruce Rigby commented that it should be "Keep rates as low as possible and service as high as possible."

Council Member Lee suggested that we have by the next meeting a few ideas drawn up to start establishing our official Mission Statement for the Power Department.

Board Member Stephenson asked what is the most complex issue or risk to managing the Power Company. What is the biggest difficulty in making sure power is there for our customers? Is it a certain time of the day? What is the peak demand? What is the biggest fear of the Power Department?

Board Member Chilcote asked about the Equipment. Power Superintendent Gary Hatch responded that the biggest issue is making sure that our system is reliable especially during our peak demand time. Power Superintendent reassured the Board that the infrastructure at the moment has enough capacity to handle the load.

Board Member Loveless feels that the study sheds a bad light on solar power. 1.6 percent of our customers are solar power users. He feels we need to focus on encouraging customers to conserve energy and encourage them to find alternative power sources.

Board Member Farnes wanted to know how many solar power customers we had a year ago compared to our customers as of this date. Bruce Rigby commented that we had 50 customers a year and half ago in July and now we have over 100 customers. Solar is a concern because of the rapid growth. We have a Net Metering Agreement between the Customer and Kaysville City Power and Light. Either party can change the agreement with a 30 day notice.

Board Member Stephenson commented that his profession is in the Gas Utility Sector with Questar Gas Company. He wanted to know what the wholesale cost compared to the retail cost is. The wholesale cost of power is 6.5 cents and the retail cost is 9.4 cents which that includes the cost of infrastructure and fixed costs.

Board Member Thayn wanted to know where our resources come from and how we obtain it.

Bruce Rigby will provide that information in a document by the next meeting in March.

A discussion was held about whether or not a solar power user is on the power grid. Board Member Farnes pointed out that the solar power user is technically on the grid and should be paying a fee to be on the grid whether or not the customer is using it sporadically or all of the time. Solar batteries and storage of energy was brought into the discussion.

Council Member Lee commented that the City Council's main concern is how do we take care of our Solar Power Customers and not be a burden to our other customers that are connected to the grid. How do you tell a customer that their power rates are going up because of the Solar Power users that need the grid to be in place just in case they need it at a future date. The City Council is trying to find that line that benefits both sides and is fair.

Board Member Stephenson commented that on a regulatory perspective normally the rule of thumb is whoever causes the cost should bear the cost.

Board Member Thayn wants to know what is our main focus and main objective. This is something that needs to be discussed. Also what are the biggest risk to the Power Company when it comes to the Solar Power User.

Board Member Chilcote suggested to the other board members that they need to come up with ideas and questions that pertain to what is fair for everyone when it comes to Solar Power and what are the main risks also. What are the recommendations and solutions that we can consider. What are the costs and mainly the hidden costs that need to be considered.

City Manager Scott commented on the fact that the city has been looking into Automated Meters. This process could take months or maybe even years. It is something that is being considered and is in the process of being implemented. He did not want to give a certain time line of when this could or would be accomplished. This is a process that could take months or maybe even years. All depending on costs and the technology needs.

Board Member Hein wanted to disclose that he works for a company that sells equipment and supplies materials for substations. His opinion is that Solar Power is for supplementing your needs. He does not agree with subsidizing the Solar Power User. The subsidies are already there for the end user by going off the grid and producing their own power and not paying the power company for that power. Society said that lets encourage people to do this and we will give them a rebate, But who is ultimately paying for that rebate are people that are not on Solar Power. The Non- Solar customer does not get any benefits from this rebate. He feels that solar power is still unproven and feels that it is unfair for everyone to pay someone a rebate thru the power rates. The Federal Government and State

Government are already subsidizing the Solar Power User. Why is the city subsidizing when it is already being done? The question was asked what are other cities doing about subsidizing solar power. Bruce Rigby commented that other cities and municipalities are going thru this same process that we are at the moment. It was suggested that by the next meeting, that information from other entities can be gathered and can be looked at for ideas and solutions and used as a reference point.

Council Member Lee suggested that the discussion on Solar Power be brought to a close for this meeting and put on another agenda for more discussion.

OTHER DISCUSSION ITEMS FOR UPCOMING MEETINGS

Board Members were asked that in the coming weeks before the next meeting to come up with ideas and information that they are looking for and to contact Power Superintendent Gary Hatch, Resource and Service Manager Bruce Rigby or City Manager Shayne Scott with these requests. Email these individuals with your requests and the information will be sent to you and the other members of the board. Council Member Lee suggested topics for future meetings. The topics are Goals and Objectives, Finances of the Power Company, Breakdown of the Budget, Resource Sources, Service Charges, Benefits and Hidden Costs of Solar Power and where we are at with Advanced Meters.

Board Member Thayne would like to have a One Line distribution map to be available to look at.

SELECTIONS OF OFFICERS

Board Member Stephenson asked that everyone take a moment and briefly explain their backgrounds and experience in the power industry before nominating individuals for offices.

Jordan Stephenson- CPA for the Regulatory Affairs for Questar Gas Company. Has been involved for the last 5 years in regulatory proceedings.

Sean Chilcote- Electrical Engineer P.E for Rocky Mountain Power. Started his own company about 9 years specializing in Substations and Power Generation.

Patrick Hein-Partner in Alpha Power System. Supply materials for substations distributions lines and transmission lines. Dealing mostly with manufactures that build these systems.

John Loveless-L3 Communications, Satellite links and line of sight links. Adjunct Professor at Weber State University. Teaches RF Type Communication Classes.

Alan Farnes-Works for Bountiful Power Company, Has been there 39 years and over the Generation, Substation and Engineering Department.

Brok Thayne- P.E Electrical Engineer. Has worked for numerous Power Distribution Companies. Started the Renewable Energy Branch at Hunt Electric. Hunt Electric is the second largest solar installer in the nation. Adjunct Professor at Salt Lake Community College in Renewable Energy Program.

Board Member Sean Chilcote nominated Brok Thayn for Chairman. Second by Board Member Patrick Hein.

The vote on the motion was as follows:

Board Member Jordan Stephenson , Yea
Board Member Sean Chilcote, Yea
Board Member Patrick Hein, Yea
Board Member John Loveless, Yea
Board Member R. Alan Farnes, Yea
Board Member Brok Thayn, Yea

Board Member Alan Farnes nominated Sean Chilcote for Vice Chairman. Second by Board Member Jordan Stephenson.

The vote on the motion was as follow:

Board Member Jordan Stephenson , Yea
Board Member Sean Chilcote, Yea
Board Member Patrick Hein, Yea
Board Member John Loveless, Yea
Board Member R. Alan Farnes, Yea
Board Member Brok Thayn, Yea

Chairman Brok Thayn will conduct the Power Commission Board Meeting according to the posted agenda. Vice Chairman Sean Chilcote will conduct meeting in the absence of the chairman.

CALL TO THE PUBLIC

Greg Lewis would like to see peak mandated on time of the day and time of the year. Would like to know if the power rates differ during the peak times and non-peak times. Would like to see a set surcharge and not a variable rate. He would also like to talk to Board Member John Loveless about his solar power system that he has on his home. Would also like to see a “feel good” box on our power bill that can be checked if the customer would like to buy more of green power at a higher rate.

Board Member Brok Thayn made a motion for adjournment at 9:10 P.M. Second by Board Member Alan Farnes and passed unanimously.



MEETING NOTICE AND AGENDA

Notice is hereby given that the Kaysville City Power Commission will hold a regular meeting on Tuesday, March 7, 2017 starting at 7:00 p.m. in the Council Room of the Kaysville City Municipal Center, 23 East Center Street, Kaysville, UT.

The agenda shall be as follows:

1. Opening Ceremonies.
2. Approval of Minutes.
3. Conference Call with Mark Beauchamp UFS
4. Solar Discussion
5. Rate Study Discussion
6. Mission Statement
7. Other Discussion Items for Upcoming Meetings
8. Call to the Public
9. Adjournment

Kaysville City is dedicated to a policy of non-discrimination in admission to, access to, or operations of its programs, services or activities. If you need special assistance due to a disability, please contact the Kaysville City Offices at (801) 546-1235.

I hereby certify that I posted a copy of the foregoing Notice and Agenda at City Hall and emailed copies to media representatives on March 1, 2017.

Stacie Harward

Stacie Harward
Administrative Assistant
Kaysville City Power Department

Utility Rate Making Concepts

For Kaysville Power Board

Jordan Stephenson

2/28/2017

Contents – 5 Slides

- Rate Making Overview – 1 Slide
- Revenue Requirement Makeup – 1 Slide
- Cost-to-Serve and Rate Design – 1 Slide
- Example: Net-Metering COS and Rate Design – 2 Slides

Rate Making Overview

Step 1

Revenue Requirement

Determine the total amount of expense/cash needs.

- O&M
- + Depreciation
- + Future Capital needs
- + Repayment of debt
- = Total Revenue Requirements



Step 2

Cost-of-Service

Allocate the revenue requirement to specific customer classes (residential, commercial, industrial, etc.)



Step 3

Rate Design

Rates are designed for each customer class to collect that classes portion of the revenue requirement. The sum of the revenue from each class equals the total revenue requirement of the utility.

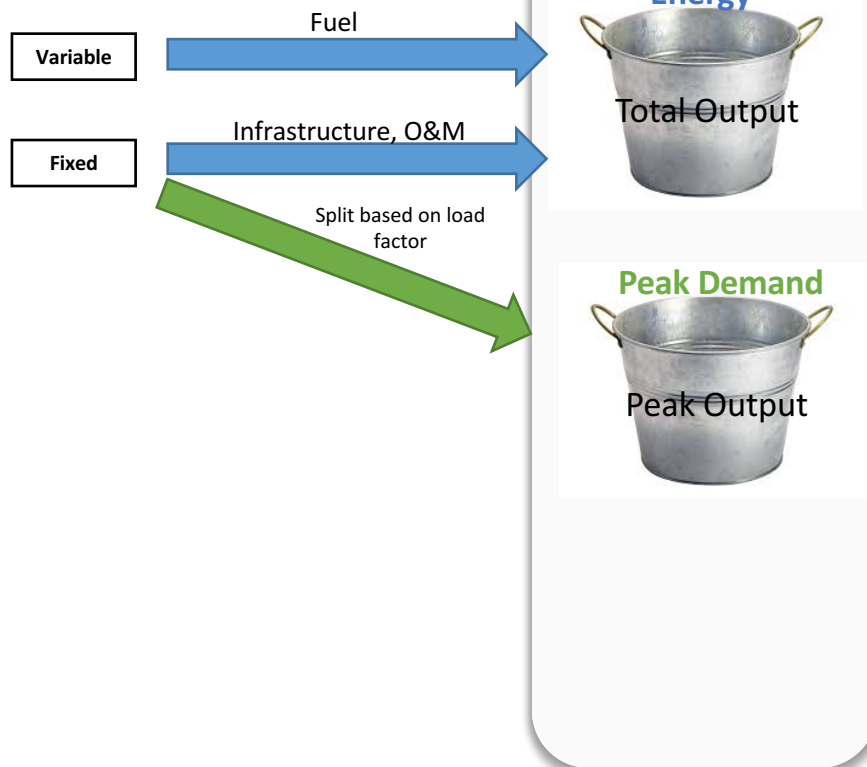
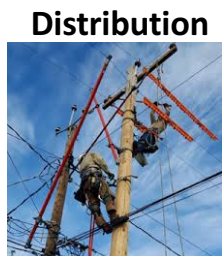


Step 1 – Revenue Requirement Makeup

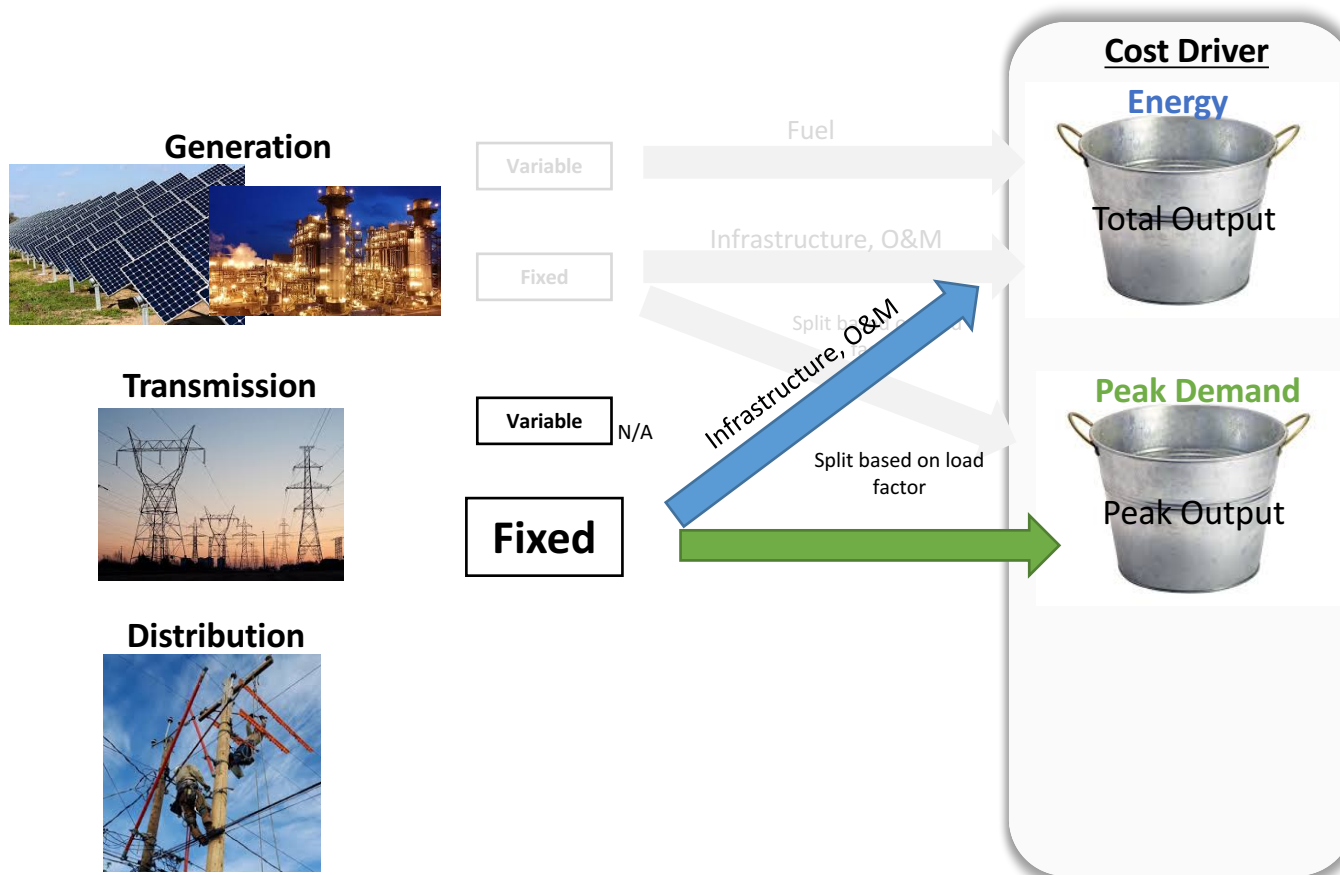


Total Revenue Requirement

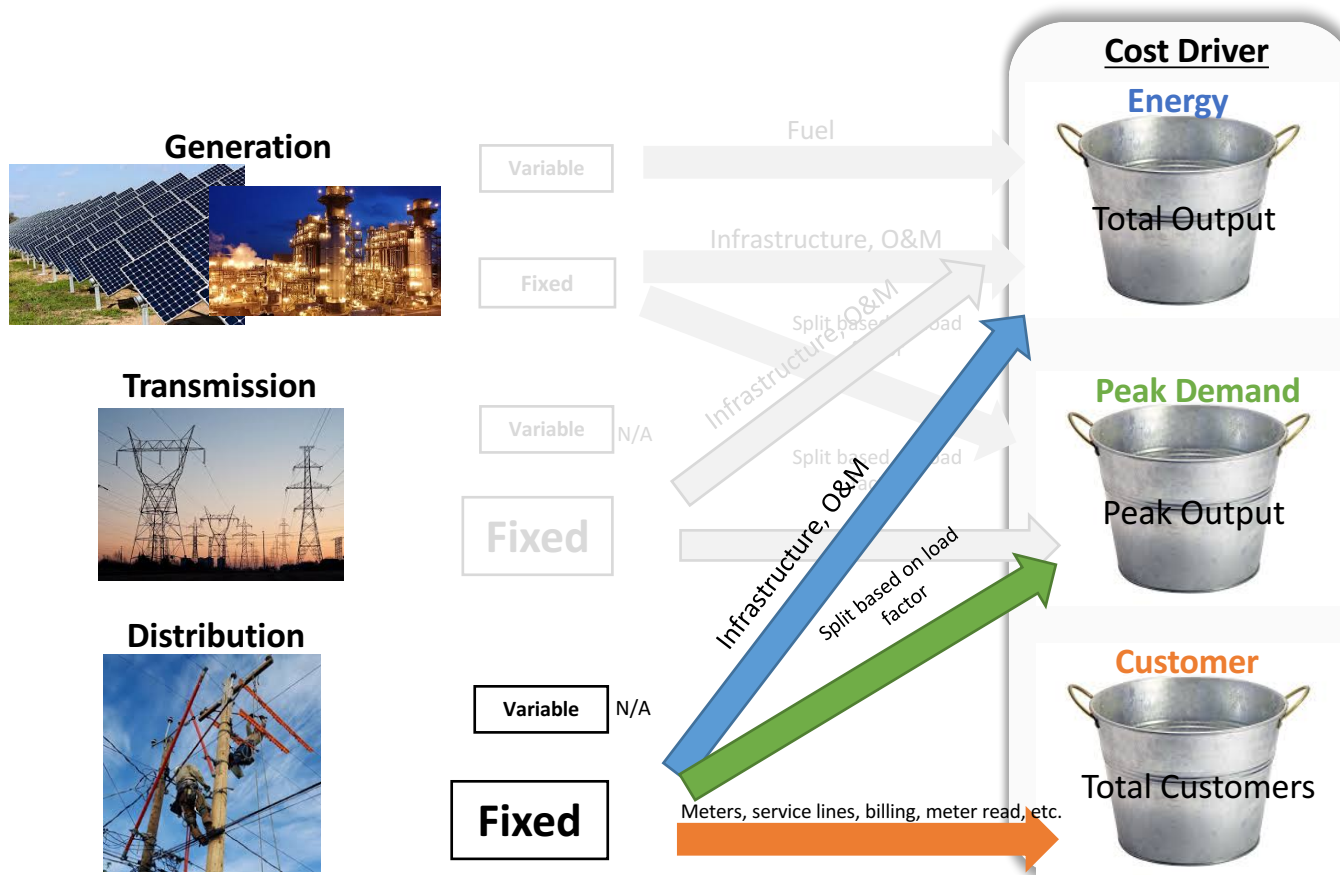
Cost-to-Serve and Rate Design



Cost-to-Serve and Rate Design



Cost-to-Serve and Rate Design



Cost-to-Serve and Rate Design

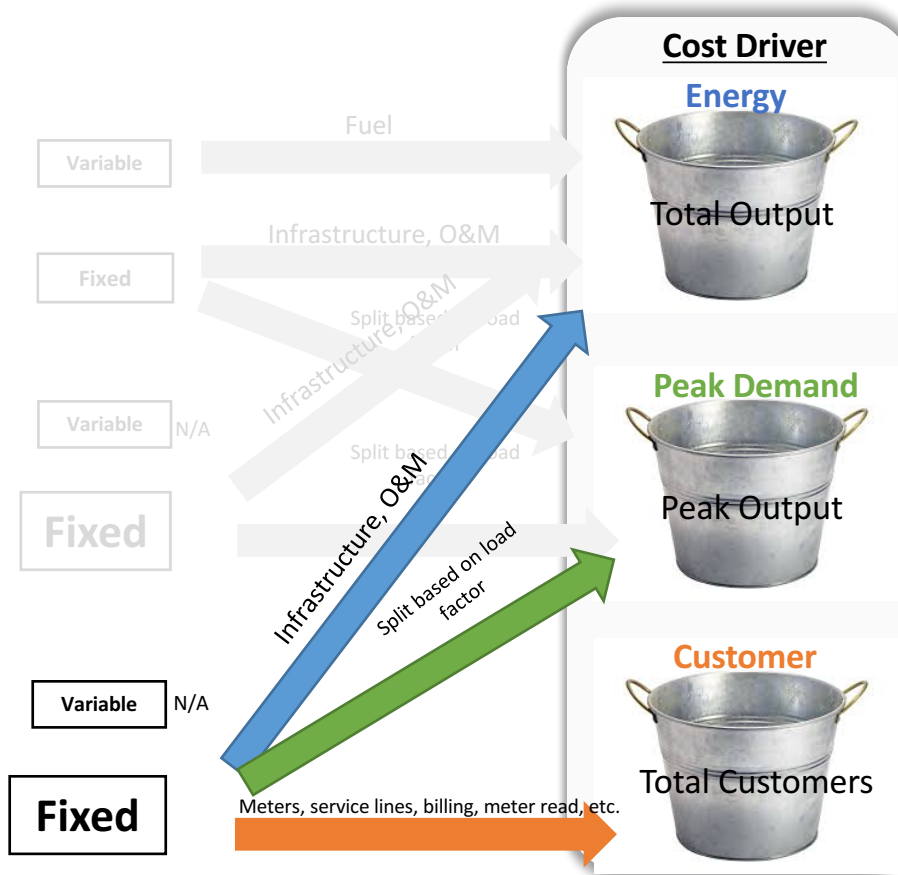
Generation



Transmission



Distribution



Crafting the Bill

Energy Charge

$$\begin{aligned} &\text{Generation Energy \$} \\ &+ \text{Transmission Energy \$} \\ &+ \text{Distribution Energy \$*} \\ &\text{Total Energy \$} \\ &\div \\ &\text{Total kWh} \\ &= \text{Energy \$ per kWh} \end{aligned}$$

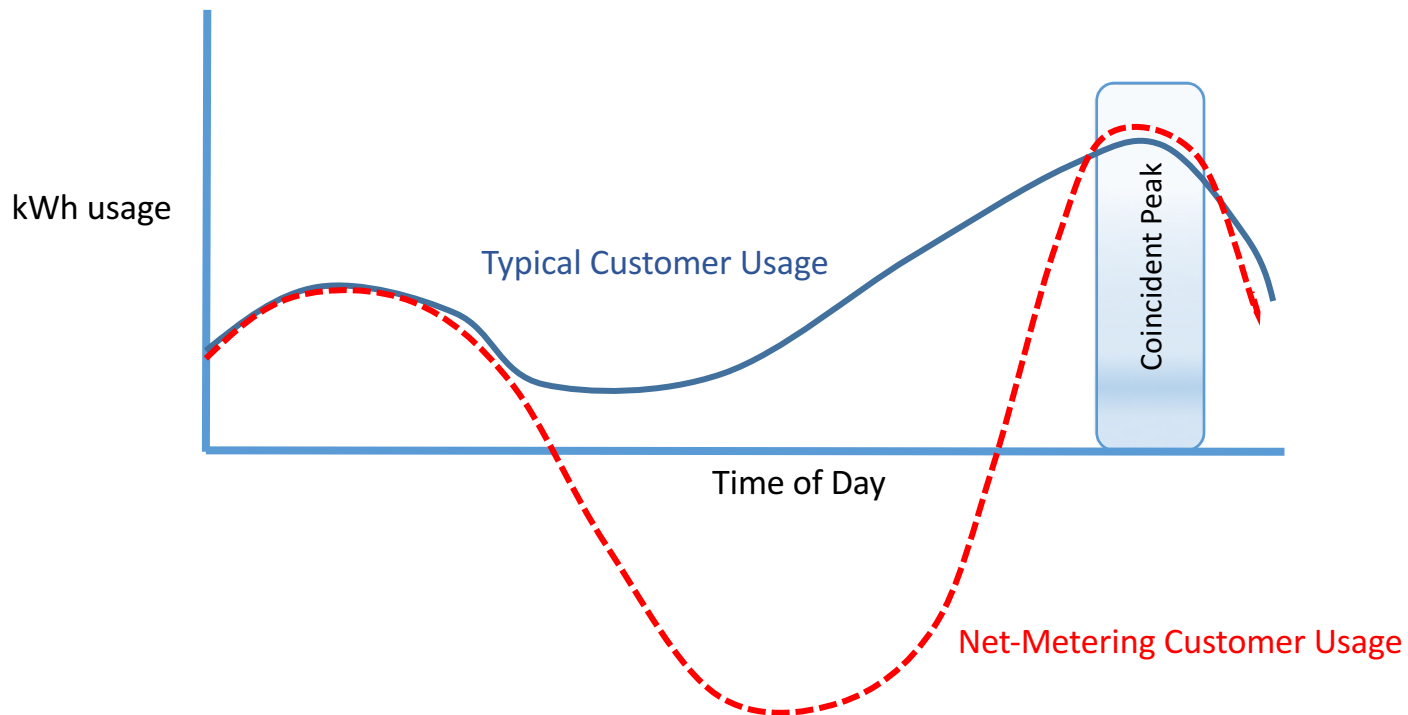
Demand Charge

$$\begin{aligned} &\text{Generation Demand \$} \\ &+ \text{Transmission Demand \$} \\ &+ \text{Distribution Demand \$*} \\ &\text{Total Peak Demand \$} \\ &\div \\ &\text{Total Coincident Peak kWh} \\ &= \text{Demand \$ per peak kWh} \end{aligned}$$

Customer Charge

$$\begin{aligned} &\text{Total customer \$} \\ &\div \\ &\text{Total Customers} \\ &= \text{Customer \$ per customer} \end{aligned}$$

Example: Net Metering Cost-to-Serve and Rate Design



Example: Net-Metering Cost-to-Serve and Rate Design

Scenario: Customer offsets total usage while net-metering, but peak usage remains unchanged



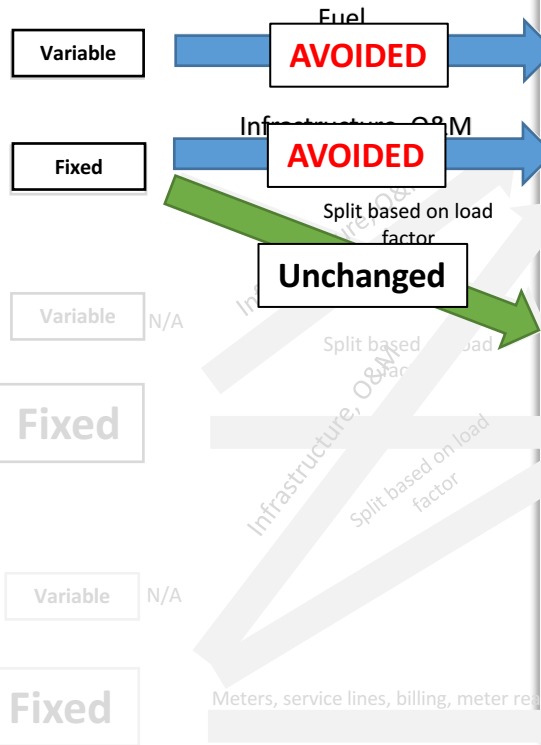
Generation



Transmission



Distribution



Cost Driver

Energy



Peak Demand



Customer



Crafting the Bill

Energy Charge

Generation Energy \$
 +Transmission Energy \$
 +Distribution Energy \$*
 Total Energy \$
 ÷
 Total kWh
 = Energy \$ per kWh

Demand Charge

Generation Demand \$
 +Transmission Demand \$
 +Distribution Demand \$*
 Total Peak Demand \$
 ÷
 Total Coincident Peak kWh
 = Demand \$ per peak kWh

Customer Charge

Total customer \$
 ÷
 Total Customers
 = Customer \$ per customer



Example: Net-Metering Cost-to-Serve and Rate Design

Scenario: Customer offsets total usage by net metering, but peak usage remains unchanged



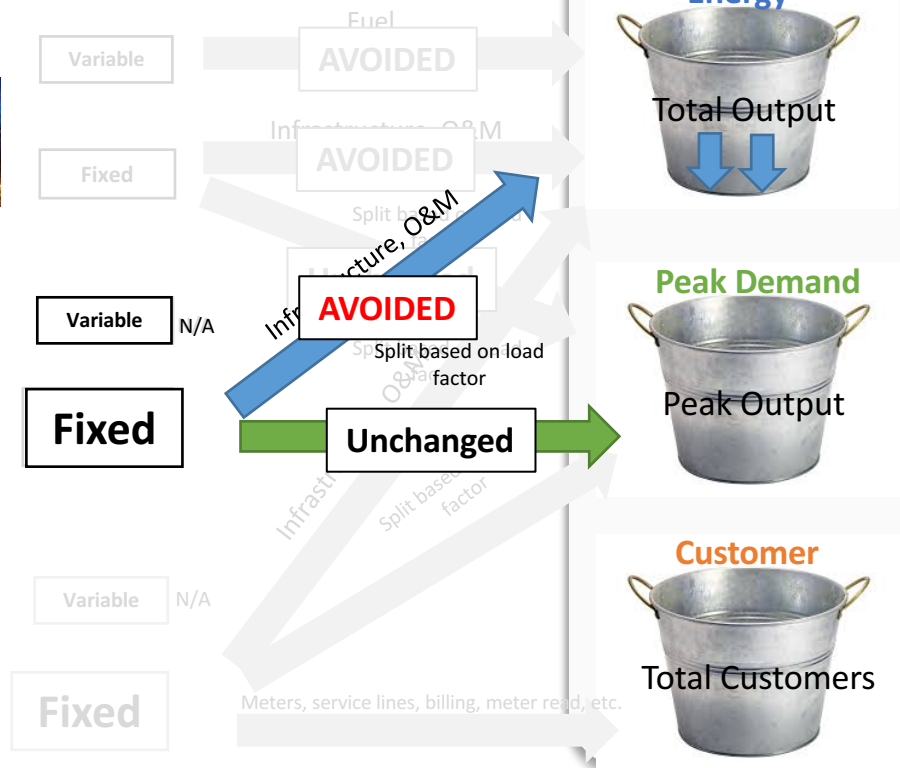
Generation



Transmission



Distribution



Crafting the Bill

Energy Charge

Generation Energy \$
+Transmission Energy \$
+Distribution Energy \$*
Total Energy \$
÷
Total kWh
= Energy \$ per kWh

Demand Charge

Generation Demand \$
+Transmission Demand \$
+Distribution Demand \$*
Total Peak Demand \$
÷
Total Coincident Peak kWh
= Demand \$ per peak kWh

Customer Charge

Total customer \$
÷
Total Customers
= Customer \$ per customer



Example: Net-Metering Cost-to-Serve and Rate Design

Scenario: Customer offsets total usage by net metering, but peak usage remains unchanged

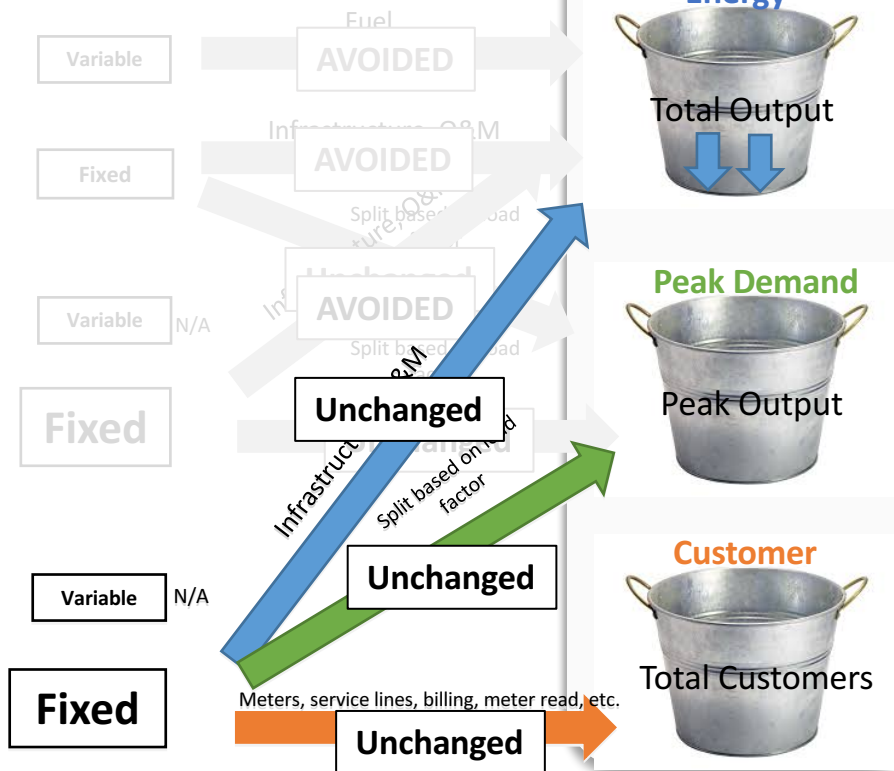
Generation



Transmission



Distribution



Crafting the Bill

Energy Charge

Generation Energy \$
 +Transmission Energy \$
 +Distribution Energy \$*
 Total Energy \$
 ÷
 Total kWh
 = Energy \$ per kWh

Demand Charge

Generation Demand \$
 +Transmission Demand \$
 +Distribution Demand \$*
 Total Peak Demand \$
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 Total Coincident Peak kWh
 = Demand \$ per peak kWh

Customer Charge

Total customer \$
 ÷
 Total Customers
 = Customer \$ per customer



Kaysville City, UT

Electric Rate Study Results

Mark Beauchamp, CPA, CMA, MBA
President
Utility Financial Solutions
616-393-9722

Assumptions

- Purchase Power
 - 2.5% increase through 2021
- Annual Inflation
 - 2.5% increase through 2021
- Annual Growth
 - 1.5% increase through 2021
- Financing New Building
 - Start building in 2020
 - Over 12 years
 - 6% interest rate
- Capital Plan
 - 2017 – With and Without AMI
 - Excluded building cost of \$4.6M

Projection without Rate Change

Capital including AMI

Fiscal Year	Projected Rate Adjustments	Debt Coverage Ratio	Projected Expenses	Projected Revenues	Adjusted Operating Income	Target Operating Income	Projected Cash Balances	Recommended Minimum Cash
2017	0.0%	-	\$ 14,089,552	\$ 12,350,988	\$ (998,015)	\$ 986,760	\$ 4,288,102	\$ 3,253,895
2018	0.0%	-	14,647,547	12,537,253	(1,366,043)	1,072,010	1,369,087	3,065,123
2019	0.0%	-	15,199,605	12,726,337	(1,725,296)	1,095,260	129,299	2,778,385
2020	0.0%	-	15,740,377	12,918,283	(2,070,382)	1,118,510	(1,439,001)	2,893,759
2021	0.0%	-	16,300,905	13,113,134	(2,432,300)	1,141,760	(3,347,094)	3,011,326

Capital Excluding AMI

Fiscal Year	Projected Rate Adjustments	Debt Coverage Ratio	Projected Expenses	Projected Revenues	Adjusted Operating Income	Target Operating Income	Projected Cash Balances	Recommended Minimum Cash
2017	0.0%	-	\$ 14,089,552	\$ 12,350,988	\$ (998,015)	\$ 986,760	\$ 5,888,102	\$ 2,933,895
2018	0.0%	-	14,623,305	12,537,253	(1,341,800)	1,072,010	2,977,087	3,065,123
2019	0.0%	-	15,175,363	12,726,337	(1,701,053)	1,095,260	1,745,339	2,778,385
2020	0.0%	-	15,716,134	12,918,283	(2,046,139)	1,118,510	185,119	2,893,759
2021	0.0%	-	16,276,662	13,113,134	(2,408,057)	1,141,760	(1,722,048)	3,011,326

Recommended Rate Track

Capital including AMI

Fiscal Year	Projected Rate Adjustments	Debt Coverage Ratio	Projected Expenses	Projected Revenues	Adjusted Operating Income	Target Operating Income	Projected Cash Balances	Recommended Minimum Cash
2017	4.4%	-	\$ 14,089,552	\$ 12,890,032	\$ (458,972)	\$ 986,760	\$ 4,827,146	\$ 3,253,895
2018	4.4%	-	14,647,547	13,655,585	(247,711)	1,072,010	3,029,158	3,065,123
2019	4.4%	-	15,199,605	14,466,725	15,092	1,095,260	3,538,058	2,778,385
2020	2.2%	-	15,740,377	15,005,472	16,808	1,118,510	4,073,991	2,893,759
2021	2.2%	-	16,300,905	15,564,299	18,865	1,141,760	4,637,433	3,011,326

Capital Excluding AMI

Fiscal Year	Projected Rate Adjustments	Debt Coverage Ratio	Projected Expenses	Projected Revenues	Adjusted Operating Income	Target Operating Income	Projected Cash Balances	Recommended Minimum Cash
2017	4.3%	-	\$ 14,089,552	\$ 12,877,781	\$ (471,223)	\$ 986,760	\$ 6,414,895	\$ 2,933,895
2018	4.3%	-	14,623,305	13,629,634	(249,420)	1,072,010	4,598,894	3,065,123
2019	4.3%	-	15,175,363	14,425,495	(1,895)	1,095,260	5,074,414	2,778,385
2020	2.2%	-	15,716,134	14,962,703	(1,719)	1,118,510	5,575,259	2,893,759
2021	2.2%	-	16,276,662	15,519,933	(1,258)	1,141,760	6,101,842	3,011,326

Electric Cost of Service Results

Customer Class	Cost of Service	Projected Revenues	% Change
Residential	\$ 8,912,364	\$ 8,210,895	8.5%
Commercial	4,973,222	3,765,593	32.1%
Industrial	190,332	124,755	52.6%
Area Lights	14,425	13,308	8.4%
Street Lights	145,421	136,437	6.6%
Total	\$ 14,235,764	\$ 12,250,988	16.2%

Energy Charges

Customer Class	Cost of Service	Projected Revenues
	\$/kWh	\$/kWh
Residential	0.1023	0.0943
Area Lights	0.1695	0.1563
Street Lights	0.2933	0.2752
Commercial	0.1082	0.0820
Industrial	0.1035	0.0679

Monthly Charge

Customer Class	Current Customer Charge	COS Customer Charge
Residential	\$ -	\$ 13.05
Commercial	-	53.62
Industrial	-	139.20

Alternative One

Continue Subsidizing Roof Top Solar Customers

- Kaysville currently “net meters” customers allowing production from solar unit to be netted against the retail electric rates
- Solar companies and customers with roof top solar prefer this practice as it improves the economics to install solar
- As solar continues to grow the subsidy and rate impacts can grow uncontrollably and may result in substantial rate increases to non-solar customers

Impacts of Cost Shift Continued program

	Installed Solar			
Installed kW	700	1,000	2,000	4,000
Cost Shift - kW	4.51	4.51	4.51	4.51
Total Cost Shift	37,883	54,118	108,236	216,472
Percent Increase to Non-Solar Customers	0.3%	0.4%	0.9%	1.8%
Monthly dollar impact on residential	0.25	0.36	0.72	1.44

* Note that the installed solar as of 02/13/2017 was 1,000 kW

Alternative One

Pros and cons

- Pros:
 - Promotes roof top solar installations
 - Can continue with current practice of crediting at retail electric rates
- Cons:
 - Non-Solar customers will be providing a subsidy to customers installing roof top solar
 - Low income customers typically do not install roof top solar and may provide subsidies to more affluent customers installing roof top solar
 - Subsidy of \$4.51/month per installed kW of solar will need to be recovered from other ratepayers

Alternative Two

Up-Front Charge for roof top solar customers

- Solar Companies expressed a desire to implement an upfront charge when customers install a solar array to recover the un recovered costs and continue to net meter and bill customers under the current method
- Two difficulties are encountered under this scenario:
 - Discount rate used in the present value – 4% discount rate was used
 - Period of time to recover stranded costs – 20 year recovery was used in the determination

Alternative Two

Up-Front Charge for roof top solar customers

Up Front Charges	
Period	No Subsidy kW-Solar Monthly
1 \$	4.51
2 \$	4.51
3 \$	4.51
4 \$	4.51
5 \$	4.51
6 \$	4.51
7 \$	4.51
8 \$	4.51
9 \$	4.51
10 \$	4.51
11 \$	4.51
12 \$	4.51
13 \$	4.51
14 \$	4.51
15 \$	4.51
16 \$	4.51
17 \$	4.51
18 \$	4.51
19 \$	4.51
20 \$	4.51
Discount Rate	
4.0%	
Rate per kW-Month	
\$61.29	
Up Front Charges - kW \$	
735.48	

Alternative One

Pros and Cons

- Pros:
 - Allows use of continued net metering program
 - Can continue with current practice of crediting at retail electric rates
 - Prevents subsidy to solar customers
- Cons:
 - Up front cost would result in a cost barrier for customers considering the installation of roof top solar

Alternative Three

eliminate subsidy to roof top solar customers

- Kaysville would continue “net metering” residential customers and allow production from solar unit to be netted against electric rates
- Rates would include an additional monthly customer charge based on the size of the solar array of \$4.51/Month – kW of installed solar
- Electric Companies prefer this approach as it eliminates the subsidy to customers installing roof top solar

Alternative Three

Eliminate Subsidizing roof top solar customers

- Set credit for production at the avoided cost value of solar. Charge under-recovery as an additional monthly charge per kW of installed solar

Residential Charge per kW of Solar Installation		
Average Residential Rate *	\$	0.09429
PCA	\$	-
Average Net Rate (Residential and PCA)	\$	0.09429
Avoided Cost Long-Run		0.05546
Lost Revenues per kWh		0.03883
Annual kWh production from 1 kW of Solar		1,394
Annual Under-Recovery from Solar	\$	54.12
Additional Monthly Charge per kW of installed Solar	\$	4.51

Alternative three

Pros and Cons

- Pros:
 - Eliminates subsidy to roof top solar
 - Prevents additional rate increases to other customers
 - Fixed monthly charge simplifies the billings
- Cons:
 - Discourages roof top solar installations
 - Current roof top solar customers may see a large increase in their monthly bills

Cost Shift and Rate Impacts

UFS Option Capped Cost Shift

Council Approved Cost Shift	25,000	0.20%
	Solar	Monthly
Installed Solar kW	700	1.53
Installed Solar kW	1,000	2.43
Installed Solar kW	2,000	3.47
Installed Solar kW	4,000	3.99
Additional Residential Charges per month without solar		0.17

Council Approved Cost Shift	50,000	0.41%
	Solar	Monthly
Installed Solar kW	700	-
Installed Solar kW	1,000	0.34
Installed Solar kW	2,000	2.43
Installed Solar kW	4,000	3.47
Additional Residential Charges per month without solar		0.33

Council Approved Cost Shift	100,000	0.82%
	Solar	Monthly
Installed Solar kW	700	-
Installed Solar kW	1,000	-
Installed Solar kW	2,000	0.34
Installed Solar kW	4,000	2.43
Additional Residential Charges per month without solar		0.67

Alternative four

Pros and Cons

- Pros:
 - Limits the subsidy to roof top sola
 - Additional rate increases to other customers are pre-determined and capped
 - Current roof top solar customers will see no immediate impact on charges
 - Future increases should be small depending on roof top solar installations
 - Fixed monthly charge simplifies the billings
- Cons:
 - Calculation has to be reviewed annually to determine the next years charges (if any)
 - Non Solar customers will see a small increase in electric rates in the long term
 - Periodic revue of avoided cost should be done every three years, with calculation completed each year

Option Eliminate Subsidy with Upfront Charge and Monthly kW Charge

Up Front Charge	Percent Reduction of Subsidy	Current Subsidy - kW	Adjusted Subsidy	Monthly Charge - kW	Cost Shift - kW	Monthly Charge per kW to Remove Cost Shft
100	14%	\$ 4.51	\$ 3.90	2.06	1.84	3.90
200	27%	\$ 4.51	\$ 3.28	2.06	1.22	3.28
300	41%	\$ 4.51	\$ 2.67	2.06	0.61	2.67
400	54%	\$ 4.51	\$ 2.06	2.06	(0.00)	2.06

Solar Companies Preferred Option

- Increase Residential Customer Charges to \$5.00 per Month (Cost of Service \$13.05)
- This will reduce subsidy per kW of Installed Solar from \$4.51 to \$3.91

	Installed Solar			
Installed kW	700	1,000	2,000	4,000
Cost Shift - kW	3.91	3.91	3.91	3.91
Total Cost Shift	32,844	46,920	93,840	187,680
Percent Increase to Non-Solar Customers	0.3%	0.4%	0.8%	1.5%
Monthly dollar impact on residential	0.22	0.31	0.63	1.25

* Note that the installed solar as of 02/13/2017 was 1,000 kW

Solar Companies Option Three

- Include a charge per kW of installed solar:
 - \$1.00 for first three kW
 - \$1.00 per additional kW
 - Reduce cost shift by an additional 0.60/kW
 - Combined reduction in cost s

	Installed Solar			
Installed kW	700	1,000	2,000	4,000
Cost Shift - kW	3.31	3.31	3.31	3.31
Total Cost Shift	27,804	39,720	79,440	158,880
Percent Increase to Non-Solar Customers	0.2%	0.3%	0.6%	1.3%
Monthly dollar impact on residential	0.19	0.26	0.53	1.06

* Note that the installed solar as of 02/13/2017 was 1,000 kW

Right Sizing Solar Array

- City Council should limit the size of the array on customers to a certain percentage of customers usage
 - Many Utilities limit the size by reviewing the customers hourly load data or annual usage prior to installing solar vs. the projected solar production.
 - The main factors to review would be:
 - Customer annual maximum demand – limit solar to a percentage of max demand.
 - Customer total annual kWh usage – limit solar to a percentage of total consumption prior to solar.
 - Customer hourly usage vs. the projected solar production to limit percent of solar being sent back to the grid.