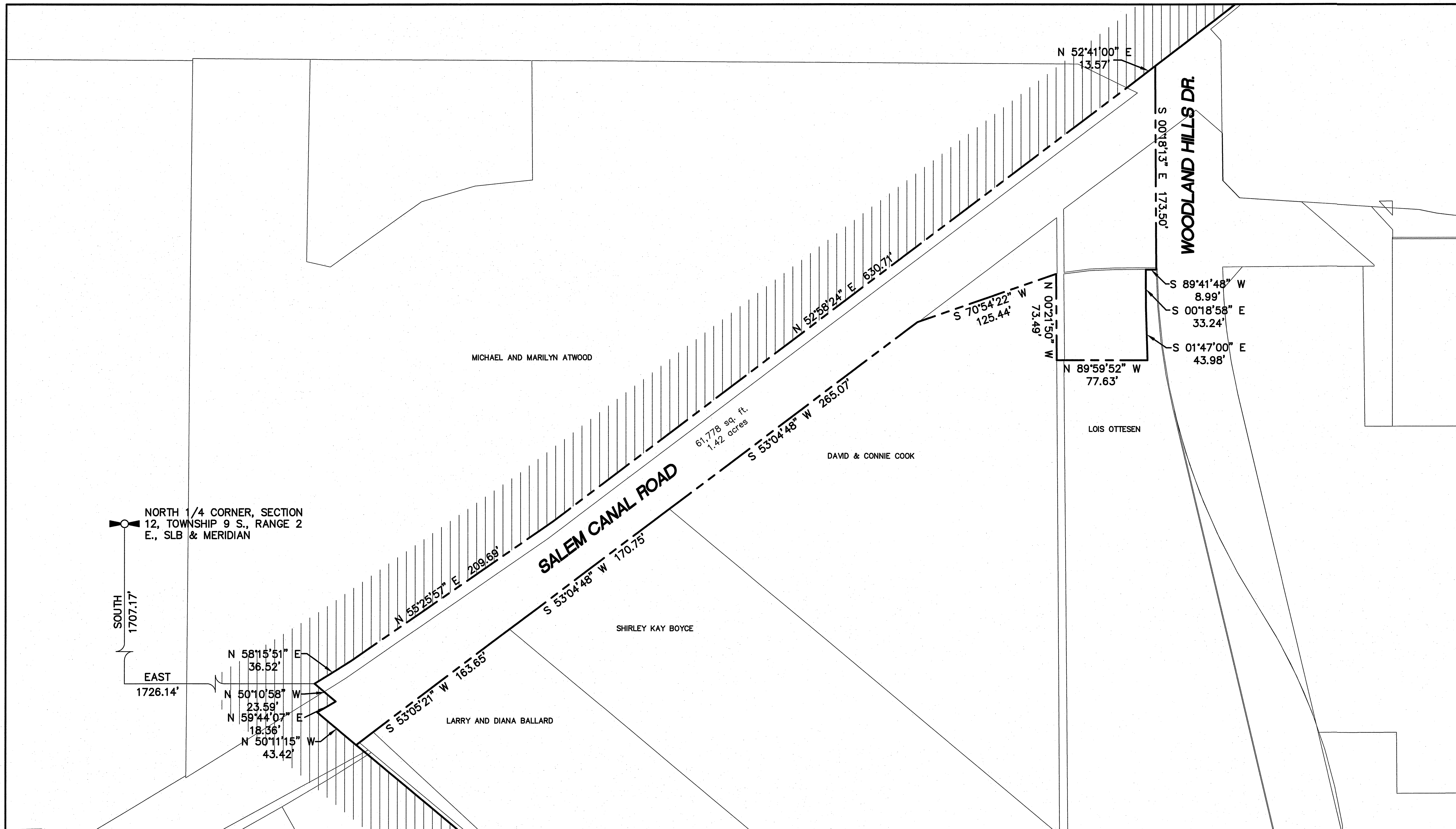
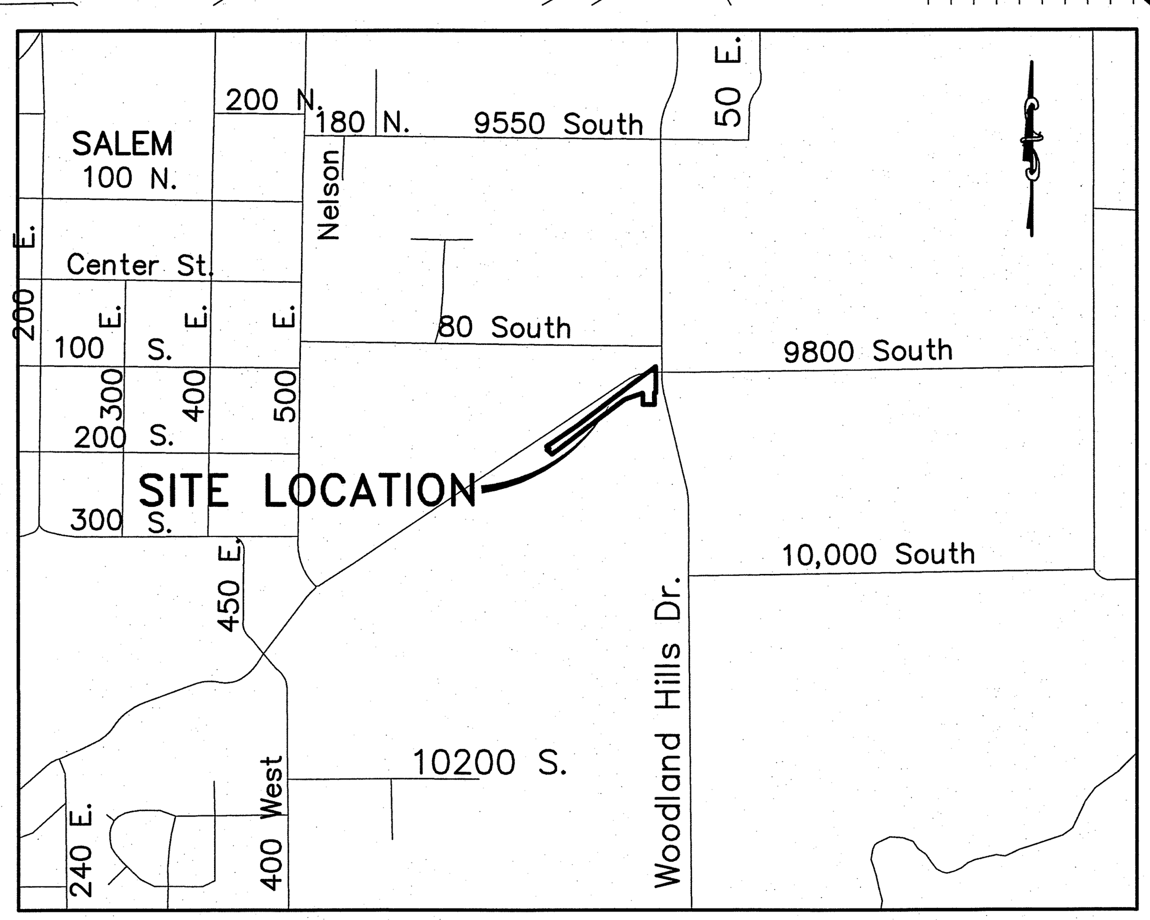
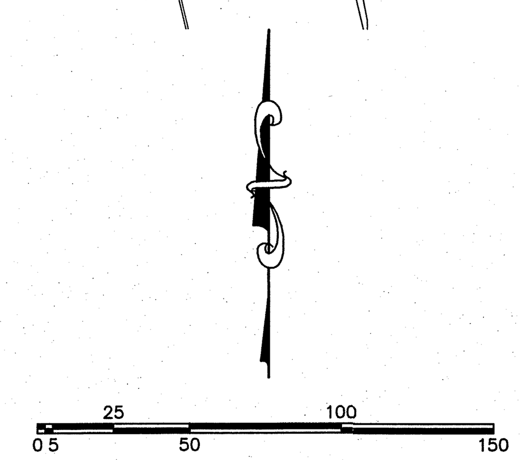




VICINITY MAP

–NTS–



(24"x36")
SCALE 1" = 50'
(11"x17")
SCALE 1" = 100'

EXISTING SALEM CITY BOUNDARY

SURVEYORS CERTIFICATE

I, BARRY PRETTYMAN DO HEREBY CERTIFY THAT I AM A PROFESSIONAL LAND SURVEYOR, AND THAT I HOLD CERTIFICATE NO. 166406 AS PRESCRIBED UNDER THE LAWS OF THE STATE OF UTAH. I FURTHER CERTIFY THAT THIS IS A TRUE AND ACCURATE MAP OF THE TRACT, BASED ON UTAH COUNTY NAD27, OF LAND TO BE ANNEXED INTO SALEM CITY, UTAH COUNTY, UTAH.

BOUNDARY DESCRIPTION

COMMENCING AT A POINT THAT IS SOUTH 1707.17 FEET AND EAST 1726.14 FEET FROM THE THE NORTH 1/4 CORNER OF SECTION 12, TOWNSHIP 9 SOUTH, RANGE 2 EAST, SALT LAKE BASE AND MERIDIAN;
AND RUNNING THENCE N58°15'51"E 36.52 FEET; THENCE N55°25'57"E 209.69 FEET; THENCE N52°58'24"E 630.71 FEET; THENCE N52°41'00"E 13.57 FEET; THENCE S00°18'13"E 173.50 FEET; THENCE S89°41'48"W 8.99 FEET; THENCE S00°18'58"E 33.24 FEET; THENCE S01°47'00"E 43.98 FEET; THENCE N89°59'52"W 77.63 FEET; THENCE N00°21'50"W 73.49 FEET; THENCE S70°54'22"W 125.44 FEET; THENCE S53°04'48"W 265.07 FEET; THENCE S53°04'48"W 170.75 FEET; THENCE S53°05'21"W 163.65 FEET; THENCE N50°11'15"W 43.42 FEET; THENCE N59°44'07"E 18.36 FEET; THENCE N50°10'58"W 23.59 FEET TO THE POINT OF BEGINNING. CONTAINS 1.42 ACRES.

SURVEYOR DATE

ACCEPTANCE BY THE CITY ENGINEER

CITY ENGINEER DATE

ACCEPTANCE BY THE LEGISLATIVE BODY

THIS IS TO CERTIFY THAT WE THE UNDERSIGNED SALEM CITY COUNCIL HAVE ADOPTED A RESOLUTION OF ITS INTENT TO ANNEX THE TRACT OF LAND SHOWN HEREIN AND HAVE SUBSEQUENTLY ADOPTED AN ORDINANCE ANNEXING SAID TRACT INTO SALEM CITY, UTAH AND THAT A COPY OF THE ORDINANCE HAS BEEN PREPARED FOR FILING HEREWITH ALL IN ACCORDANCE WITH UTAH COUNTY CODE SECTION 10-2-418 AS REVISED AND THAT WE HAVE EXAMINED AND DO HEREBY APPROVE AND ACCEPT THE ANNEXATION OF THE TRACT AS SHOWN AS PART OF SAID CITY AND THAT SAID TRACT OF LAND IS TO BE KNOWN HEREAFTER AS THE WARNER ANNEXATION

DATED THIS________ DAY OF____________________,2016

CLERK RECORDER DATE

ACCEPTANCE BY UTAH COUNTY SURVEYOR

UTAH COUNTY SURVEYOR DATE

ANNEXATION PLAT

ATWOOD ANNEXATION

SALEM CITY, UTAH COUNTY,
UTAH

Z:\2016\16-067 Hugely Salem\CADD\ANNEXATION\ANNEXATION.dwg 8/9/2016 1:24:18 PM MDT

Attachment A

TASK ORDER NO. 2016-06
TO
MASTER AGREEMENT FOR PROFESSIONAL SERVICES

OWNER: CITY OF SALEM
Effective Date of AGREEMENT: _September 17, 2014__

TASK ORDER NO. 2016-06 ("this TASK ORDER") to the CITY OF SALEM MASTER AGREEMENT FOR PROFESSIONAL SERVICES (AGREEMENT) is made and entered into as of the ____ day of ______________, 20___, by and between OWNER and Forsgren Associates, Inc., a Utah Corporation (herein called ENGINEER) who agree as follows:

1. **PROJECT.** The PROJECT associated with this TASK ORDER is described as follows: New Wastewater Treatment Plant.
2. **PROJECT SITE**. The PROJECT SITE is located as follows: New Wastewater Treatment Plant site.
3. **SCOPE OF SERVICES.** The SCOPE OF SERVICES and deliverables associated with this TASK ORDER are attached hereto as Exhibit A.
4. **FEES.** OWNER shall reimburse for services provided under this TASK ORDER for the amounts described in the scope of services. Payment shall be in accordance with the updated FEE SCHEDULE attached hereto as Exhibit B and in accordance with the AGREEMENT.
5. **SCHEDULE & FUNDING.** The SERVICES associated with this TASK ORDER are anticipated to be completed as shown on the schedule included in the scope of services, following written authorization from the OWNER to proceed. ENGINEER understands that the OWNER is anticipating they will receive funding from a Utah DWQ Loan to pay for this work. If funding is not ultimately approved and/or received the ENGINEER will not receive compensation for ANY work completed under this TASK ORDER unless OWNER specifically authorizes ENGINEER in writing to proceed on such work. ENGINEER shall not proceed with any work on any sub-task of this TASK ORDER without a written notice to proceed from OWNER.
6. **ATTACHMENTS AND EXHIBITS.** Both parties have read and understood all attachments and exhibits referenced in or attached to this TASK ORDER and agree that such items are hereby incorporated into and made a part of the AGREEMENT.

IN WITNESS WHEREOF, OWNER and ENGINEER have executed this TASK ORDER as of the date first above written.

OWNER:	**ENGINEER:**
By:______________________________	By: ______________________________
Printed Name:______________________	Printed Name:______________________
Its: ______________________________	Its: ______________________________

EXHIBIT A

SCOPE OF SERVICES
FOR
DESIGN, BIDDING, AND CONSTRUCTION SERVICES
FOR THE
NEW WASTEWATER TREATMENT PLANT
FOR
SALEM CITY

PROJECT:

New Wastewater Treatment Plant

PURPOSE:

Salem City will construct a new wastewater treatment plant (WWTP) to replace the existing lagoon system, pursuant to the findings of the Wastewater Facilities Planning Study. The preferred alternative selected in the master plan is a new biological nutrient removal system located at a new site. In general, the WWTP will be a 1.5 MGD average day flow facility, and will include lift station, headworks, odor control, oxidation ditches, clarifiers, disinfection, solids processing facilities, site improvements, and landscaping. All necessary utilities from their existing location to the new site are included in this project.

SCOPE OF SERVICES:

Forsgren Associates (Consultant) will provide engineering services for Salem City (Owner) related to design and construction of the new WWTP. Each task is described below.

Task 1 – Environmental Review

Consultant shall perform an Environmental Review (ER) in order to obtain a FONSI for the new WWTP site and pipelines alignment, and coordinate with Agency for approval of the new WWTP location. This is a time and materials not-to-exceed task, with a budget of $20,000.

It is not expected that an Environmental Assessment or Environmental Impact Study will need to be performed. If a study more extensive than an ER is determined to be necessary, then an adjustment to this the scope and budget of this task will be required.

Task 2 – Anti-Degradation Review and Discharge Permit Coordination

Consultant shall provide services and coordinate with Agency for completion of the Anti-Degradation Review, and shall assist in obtaining a revised UPDES permit for new discharge location. Engineer will provide technical criteria, written descriptions, and design data for use in filing applications for permits from governmental authorities. This is a time and materials not-to-exceed task, with a budget of $20,000.

Task 3 – Surveying and Geotechnical Investigation

Consultant shall survey the pipeline alignments and WWTP site for use in design of the pipelines and facilities, and shall perform a geotechnical investigation of the new site. This is a time and materials not-to-exceed task, with a budget of $45,000.

Task 4 – Design

Consultant shall provide the design services for the project, consisting of those activities generally associated with a project of this scope and as listed below. This is a lump sum task, with a cost of $760,000. Unforeseen or abnormal conditions discovered during the design of the project may require an adjustment to the scope and budget.

4.1 Meetings: Attend various meetings with the Owner and regulatory agencies throughout the design period upon the Owner's request.

4.2 Design to 30% Level

- 4.2.1 Complete tasks required to design the project to the 30% level.
- 4.2.2 Advise Owner if additional reports, data, information, or services (e.g., additional influent sampling) are necessary and assist Owner in obtaining such reports, data, information, or services.
- 4.2.3 Provide Preliminary Design Report to Owner and regulatory agencies for review. The report shall include the drafts of the process and controls narrative descriptions for unit processes, design criteria summaries by design discipline, listing of technical specifications, selected drawings, and preliminary design Opinion of Probable Construction Cost.
- 4.2.4 Conduct and document one 30% review workshop with Owner and Agency reviewing Preliminary Design Report.

4.3 Design to 60% Level

- 4.3.1 Provide design services to a 60% level for all necessary disciplines, including civil site, process mechanical, structural, architectural, HVAC/plumbing, electrical/controls, and SCADA integration.
- 4.3.2 Provide a 60% submittal of selected drawings for review purposes.
- 4.3.3 Conduct and document one 60% review workshop with Owner and Agency reviewing Preliminary Design Report.

4.4 Design to 90% Level

- 4.4.1 Provide design services to a 90% level for all necessary disciplines, including civil site, process mechanical, structural, architectural, HVAC/plumbing, electrical/controls, and SCADA integration.
- 4.4.2 Provide a 90% submittal of selected drawings for review purposes.
- 4.4.3 Conduct and document one 90% review workshop with Owner and Agency reviewing Preliminary Design Report.

4.5 Final Design

- 4.5.1 Prepare and furnish Final Bidding, Contract, Design, and Construction Documents for review by the Owner, its legal counsel, its other advisors, and regulatory agencies.
- 4.5.2 Prepare permit applications in order to obtain construction approvals from governmental authorities having jurisdiction to review or approve the final design of the Project; assist Owner in consultations with such authorities.
- 4.5.3 Prepare Final Design Report as appropriate after the final review submittal.
- 4.5.4 Revise all Documents in accordance with comments and instructions from the Owner and Agency, as appropriate, and submit final copies of all Documents, and revised Opinion of Probable Construction Cost, and any other deliverables to Owner and Agency.

Task 5 – Bidding and Construction Services

Engineer shall provide assistance to the Owner during the bidding and construction period of the project, consisting of the activities listed below. This is a time and materials not-to-exceed task, with a budget cost of $980,000.

5.1 Contractor Pre-Qualification

- 5.1.1 Prepare a "Request for Qualifications" document set to be distributed to interested contractors.
- 5.1.2 Prepare written advertisement (Owner to pay for advertising costs) for submission to newspapers and magazines.
- 5.1.3 Receive and answer questions on qualification documents.
- 5.1.4 Summarize and evaluate submissions received.
- 5.1.5 Provide a recommendation regarding eligible contractors.

5.2 Bidding

- 5.2.1 Prepare written advertisement (Owner to pay for advertising costs) for submission to newspapers and magazines.
- 5.2.2 Conduct pre-bid meeting.
- 5.2.3 Distribute bid documents.
- 5.2.4 Receive and answer questions on bid documents.
- 5.2.5 Prepare addenda to bid documents if needed and distribute to plan holders.
- 5.2.6 Conduct bid opening.
- 5.2.7 Summarize and evaluate bids received.
- 5.2.8 Provide a recommendation for award.
- 5.2.9 Prepare a Notice of Award, contract documents, and Notice to Proceed.
- 5.2.10 Prepare necessary engineering documents, coordinate, and assist Owner, Bond Counsel, and Financial Advisor with loan closing funding authorizations.

5.3 Construction

Engineer will provide list and resumes of all construction personnel that will be assigned to the construction phase of the project for approval by Owner. Engineer will replace personnel at Owner's request.

- 5.3.1 Conduct a pre-construction meeting.
- 5.3.2 Provide appropriate personnel for onsite inspection services during construction (for an expected construction period of 16 months), which includes preparing daily construction reports and photographs as required.
- 5.3.3 Conduct monthly construction progress meetings.
- 5.3.4 Prepare and review progress payments for partial payments to contractors.
- 5.3.5 Answer questions and issue clarifications as necessary.
- 5.3.6 Review change order requests submitted by the Contractor.
- 5.3.7 Review submittals from the Contractor.
- 5.3.8 Prepare monthly construction progress reports for the Owner.
- 5.3.9 Prepare a notice of Substantial Completion.
- 5.3.10 Conduct a post-construction meeting to prepare a final punch list of items as determined by the Engineer and Owner to complete the work.
- 5.3.11 Prepare record drawings.
- 5.3.12 Prepare Notice of Final Completion.
- 5.3.13 Prepare documents and coordinate as necessary for funding & State oversite.

Task 6 – Startup Assistance

Engineer shall perform the tasks described below during the start-up and certification period. The certification period may commence during the construction phase and, if not otherwise modified will terminate 12 months after Final Acceptance. This is a time and materials not-to-exceed task, with a budget of $30,000.

6.1 Provide assistance in connection with the adjusting of Project equipment and systems.
6.2 Assist Owner in training Owner's staff to operate and maintain Project equipment and systems.
6.3 Assist Owner in developing procedures for control of the operation and maintenance of, and record keeping for Project equipment and systems.
6.4 Together with Owner, visit the Project to observe any apparent defects in the Work, assist Owner in consultations and discussions with Contractor concerning correction of any such defects, and make recommendations as to replacement or correction of Defective Work, if present.
6.5 Operation and Maintenance Manual (Final): Revise the draft Operations and Maintenance Manual. Submit the final version to the Owner and regulatory agencies.
6.6 In company with Owner or Owner's representative, provide an inspection of the Project within one month before the end of the Correction Period for Contractor's Work to ascertain whether any portion of the Work is subject to correction.
6.7 As required by funding and regulatory agencies and the Clean Water Act, prepare and submit the Project Certification Report. The certification report will verify that the Engineer has supervised operations, trained operating personnel, revised the operation and maintenance manual and shown that the plant is meeting design requirements.
6.8 Prepare Operating Permit and other related documents for Agency Approval to finalize the project.

SCHEDULE

The basic schedule for each task is as follows. The dates listed are approximate dates, and are subject to change.

Task	Description	Start	End
1	Environmental Review	8/1/16	11/1/16
2	Anti-Degradation and Discharge Permit Review	8/1/16	11/1/16
3	Survey and Geotechnical Investigation	9/1/16	11/1/16
4	Design	9/1/16	12/1/17
5	Bidding and Construction	12/1/17	6/1/19
6	Startup Assistance	6/1/19	6/1/20

PROJECT BUDGET

For reference, a summary of the overall project costs (as approved in the June 22, 2016, Water Quality Board meeting) is shown below.

Item	Value
Construction	
Construction Cost	$9,631,000
Construction Contingency	$1,439,000
Subtotal Construction Cost	**$11,070,000**
Professional Services	
Planning Advance	$75,000
Funding Administration	$30,000
Environmental Review	$20,000
Anti-Degredation Review	$20,000
Survey and Geotechnical Investigation	$45,000
Financial Advisor	$30,000
Bond Attorney	$30,000
Engineering Design Services	$760,000
Engineering Bidding/Construction Services	$980,000
Startup Services	$30,000
Subtotal Professional Services	**$2,020,000**
Misc Costs	
Property/Right-of-Way Purchase	$500,000
Utility Extensions (Electric, Gas, Etc.)	$300,000
Loan Origination Fee	$110,000
Subtotal Misc Costs	**$910,000**
Total Cost	**$14,000,000**

EXHIBIT B

FORSGREN Associates Inc.

FORSGREN ASSOCIATES, INC.
TITLE CODE RATE SCHEDULE
01 JANUARY 2016

TITLE CODE	TITLE	HOURLY RATE*
Engineer/Scientist VI	Principal/Service Leader	225
Engineer/Scientist V	Division Manager	185
Engineer/Scientist V	Managing Engineer/Scientist	170
Engineer/Scientist IV	Senior Engineer/Scientist	155
Engineer/Scientist III	Project Manager	125
Engineer/Scientist II	Project Engineer/Scientist	100
Engineer/Scientist I	Engineer/Scientist	90
Survey V	Chief of Survey	120
Survey IV	Survey Party Chief	105
Survey III	Senior Surveyor	80
Survey II	Surveyor in Training	75
Survey I	Survey Technician	65
Drafter IV	Senior Designer	100
Drafter III	Designer	90
Drafter II	Senior Designer	85
Drafter I	Designer	75
Inspector VI	Senior Construction Manager	130
Inspector V	Construct. Mgr/Sup. Inspect.	115
Inspector IV	Project Inspector	105
Inspector III	Project Inspector	85
Inspector II	Project Inspector	75
Inspector I	Assistant Inspector	60
Tech V	Technician Manager	125
Tech IV	Supervising Technician	95
Tech III	Senior Technician	85
Tech II	Technician	75
Tech I	Assistant Technician	65
Clerical IV	Senior Project Assistant	90
Clerical III	Project Assistant III	75
Clerical II	Project Assistant II	60
Clerical I	Project Assistant I	50

Rates are fully-loaded with direct labor, overhead and profit
Expert Witness Testimony, Preparation and all court time will be charged at a rate of $500.00 per hour.
Reimbursables are charged at cost plus 15%
Subconsultants are charged at cost plus 15%
Mileage will be charged at $0.56/mile
Rates are subject to change

ELECTRIC COST OF SERVICE AND RATE DESIGN STUDY

Final Report

June 2016

DAVE BERG CONSULTING, LLC

REPORT OUTLINE

DAVE BERG CONSULTING, LLC

June 23, 2016

Salem City Corp.
30 West 100 South St
Salem, UT 84653

Subject: Electric Rate Study

Council Members:

Dave Berg Consulting, LLC with the assistance of NewGen Strategies and Solutions, has undertaken a study of the retail rates Salem City Corp (Salem) charges its customers for electric service. This report summarizes the analyses undertaken and the resulting recommendations for changes to the existing rates.

The recommended rate adjustments have been made based on overall revenue and cash reserve needs of the utility and the results of a cost-of-service analysis. We have recommended an overall increase in electric rates of 4.2%. Additional considerations for future rate adjustments have also been recommended for the electric utility.

Thank you for the opportunity to be of service to Salem through the conduct of this study. We wish to express our appreciation for the valuable assistance we received from Salem staff relative to the execution of this study.

Sincerely,

Dave Berg Consulting, LLC

David A. Berg, PE
Principal

Section 1

Introduction

Salem, Utah owns a municipal utility providing service to approximately 2,200 retail electric customers. The electric utility (Salem) is under the direction of the Salem City Council. This report has been prepared by Dave Berg Consulting, LLC with assistance from NewGen Strategies and Solutions to examine the rates and charges for electric service in Salem City. The study includes an examination of the allocated cost of service based on actual FY 2015 utility operations (Test Year). It also includes projected operating results for FY 2016-2020 (Study Period). As a result of the analyses undertaken and reported on herein, electric rate recommendations have been developed for implementation by Salem.

Section 2
Projected Operating Results
Existing Rates

The rates charged for electric service by Salem, combined with other operating and non-operating revenues, must be sufficient to meet the cost of providing services to Salem's retail customers. This is necessary in order to ensure the long-term financial health of Salem. The cost of providing electric service consists of normal operating expenses such as purchased power, distribution functions, customer and administrative functions, system depreciation expenses, capital improvements, debt payments and contributions to Salem City and other non-operating expenses.

An analysis of the operating results for Salem during the FY 2016-2020 Study Period has been performed assuming the current retail rates and charges remain in effect for the electric utility through the Study Period. This analysis has been done to determine the overall need, if any, for additional revenue through rates to meet projected revenue requirements. The analyses and assumptions utilized in these projections are explained below.

Estimated Revenues – Existing Rates

Retail Sales

Salem sells retail power and energy to residential and commercial customers. Salem has recently been experiencing moderate growth in total retail sales to its electric customers; total sales growth after 2015 has been assumed to be approximately 3.6% per year through the Study Period. The growth is in large part due to the addition of a new health care facility with an estimated peak usage of 500 kW.

Exhibit 2-A is a summarized listing of Salem's historical and projected electric operating results at existing rates. The historical and projected revenues from retail sales of

power and energy to different groups of customers are included at the beginning of the exhibit under Operating Revenues.

Other Operating Revenues

Salem also receives revenue from other normal operating procedures. These revenues are shown in Exhibit 2-A and include connection fees, hook-ups and other miscellaneous revenues.

Utility Revenues combined with Other Operating Revenues results in Salem's Total Operating Revenues.

Revenue Requirements

Purchased Power

Salem currently meets its wholesale power requirements through its membership in the Utah Municipal Power Agency (UMPA).

Salem's actual retail sales and wholesale requirements for the FY 2015 Test Year are shown in Table 2-1.

Table 2-1
Retail Sales
And Wholesale Requirements

Item	**2015**
Metered Retail Sales	32,256,634 kWh
Losses/Unmetered (% of sales)	8.4 %
Wholesale Energy	34,975,157 kWh
Wholesale Peak	10,004 kW

For 2016-2020, annual wholesale requirements are projected to increase 3.5% per year.

Other Operating Expenses

Salem incurs other operating expenses associated with local electric system operations. Distribution operating and maintenance expenses are related to the substations, distribution lines and customer facilities located in Salem. Administrative and general expenses are required for utility management, employee benefits, training and other administrative costs. Non-wholesale power related expenses are based on 2015 values, the 2016 budget and are generally estimated to increase by 2.2% per year after 2016.

Depreciation

Salem has annual depreciation costs based on its system investments. Depreciation during the Study Period is based on budgeted Salem amounts and future capital improvements. Depreciation is a funded non-cash expense that generates monies available for annual capital improvements and reserves.

Non-operating Revenue (Expenses)

Salem's non-operating revenue is primarily associated with impact fees.

City Transfer

Salem makes an annual operational transfer to the City's general fund.

Capital Improvements

Salem makes annual normal capital investments in its electric system. Annual electric capital improvements for the Study Period, as budgeted by Salem, are shown in Table 2-2 below.

Table 2-2
Capital Improvements

Capital Item	2016	2017	2018	2019	2020
Total Capital	$20,000	$20,000	$25,000	$30,000	$30,000

Debt Service

Salem makes annual principal payments to a developer for funds advanced to Salem for a new substation. There is no interest on the debt and principal payments are made based on 50% of annual impact fee revenue.

Projected Operating Results – Existing Rates

Based on the assumptions outlined above, the resulting projected operating results assuming continued application of the existing retail rates are summarized in Table 2-3 for the electric utility. A summary presentation of the operating results is shown in Exhibit 2-A.

Table 2-3
Projected Operating Results
Existing Rates

Year	2016	2017	2018	2019	2020
Operating Revenues	$3,678,324	$4,071,447	$4,139,791	$4,213,291	$4,288,920
Less Operating Expenses	(3,592,465)	(3,939,792)	(4,066,696)	(4,197,423)	(4,314,866)
Plus Non-Operating Revenues	40,012	40,892	41,792	42,711	43,651
Less City Transfers	(338,686)	(338,686)	(338,686)	(338,686)	(338,686)
Change in Net Position	($212,815)	($166,138)	($223,798)	($280,107)	($320,981)
Net Position as Percent of Revenues	-5.8%	-4.1%	-5.4%	-6.7%	-7.5%

Cash Reserves

A summary of the impact of the projected operating results on Salem's cash reserves for the Study Period is shown at the end of Exhibit 2-A and in Table 2-4 below.

As shown below, under existing retail rates and estimated revenue requirements over the Study Period, the cash reserves for the electric utility are projected to decrease from approximately $530,000 at the end of 2015 to approximately $160,583 by the end of 2020.

Table 2-4
Projected Cash Reserves
Existing Rates

Year	2016	2017	2018	2019	2020
Beginning Balance	$533,276	$490,957	$495,541	$437,848	$319,387
Plus Change in Net Position	(212,815)	(166,138)	(223,798)	(280,107)	(320,981)
Plus Depreciation	210,502	211,168	212,002	213,002	214,002
Less Capital Improvements	(20,000)	(20,000)	(25,000)	(30,000)	(30,000)
Less Debt Principal	(20,006)	(20,446)	(20,896)	(21,356)	(21,825)
Ending Balance	$490,957	$495,541	$437,848	$319,387	$160,583
Reserves as % of Revenue	13%	12%	11%	8%	4%

Projected Operating Results

Description	Actual 2014	Actual 2015	Escalation Factor	Projected 2016	Projected 2017	Projected 2018	Projected 2019	Projected 2020
Operating Revenues								
Residential Sales			Manual	2,371,009	2,408,708	2,452,050	2,498,698	2,546,232
Commercial Sales			Manual	1,210,815	1,564,482	1,587,565	1,612,399	1,638,434
Industrial Sales			Manual	60,000	60,954	62,052	63,232	64,434
Subtotal - Charges for services	3,678,278	3,279,649		3,641,824	4,034,144	4,101,668	4,174,329	4,249,101
Connect & Reconnect Fees		23,417	General Inflation	21,500	21,973	22,456	22,950	23,455
Substation Hook-Up		466,967	General Inflation	10,000	10,220	10,445	10,675	10,909
Other Operating Revenues	14,727	41,314	General Inflation	5,000	5,110	5,222	5,337	5,455
Total Operating Revenues	**3,693,005**	**3,811,347**		**3,678,324**	**4,071,447**	**4,139,791**	**4,213,291**	**4,288,920**
Operating Expenses								
Power purchased	2,200,602	2,261,023	Manual	2,178,821	2,499,012	2,598,031	2,700,113	2,788,300
O&M Excluding Purchased Power	998,928	1,245,641	General Inflation	1,203,142	1,229,611	1,256,663	1,284,309	1,312,564
Depreciation Expense	206,697	209,835	Manual	210,502	211,168	212,002	213,002	214,002
Total Operating Expenses	**3,406,227**	**3,716,499**		**3,592,465**	**3,939,792**	**4,066,696**	**4,197,423**	**4,314,866**
Operating Income (Loss)	**286,778**	**94,848**		**85,859**	**131,655**	**73,096**	**15,868**	**(25,946)**
Nonoperating Revenues (Expenses)								
Other Non-Operating Revenue (Expenses)	204,396	179,431	General Inflation	40,012	40,892	41,792	42,711	43,651
Total Nonoperating Revenues (Expenses)	**204,396**	**179,431**		**40,012**	**40,892**	**41,792**	**42,711**	**43,651**
Transfers In (Out)	(255,804)	(305,004)	Manual	(338,686)	(338,686)	(338,686)	(338,686)	(338,686)
Operating Surplus (Deficit)	**235,370**	**(30,725)**		**(212,815)**	**(166,138)**	**(223,798)**	**(280,107)**	**(320,981)**
Beginning of Year Cash Reserves		445,881		533,276	490,957	495,541	437,848	319,387
Plus Net Income		(30,725)		(212,815)	(166,138)	(223,798)	(280,107)	(320,981)
Plus Depreciation		209,835		210,502	211,168	212,002	213,002	214,002
Less Capital Improvements		(2,000)		(20,000)	(20,000)	(25,000)	(30,000)	(30,000)
Less Debt Service Prinicpal		(89,716)		(20,006)	(20,446)	(20,896)	(21,356)	(21,825)
End of Year Cash Reserves		**533,276**		**490,957**	**495,541**	**437,848**	**319,387**	**160,583**

Section 3

Cost-of-Service

A cost-of-service analysis was performed to determine the allocated cost to serve each of Salem's customer classes within the electric utility. Customer classes exist, in part, because the cost to serve different kinds of customers varies. The cost-of-service analysis has been performed on a FY 2015 'Test Year' based on actual 2015 financials, operations and sales. The results of the cost-of-service study give an indication of the degree of revenue recovery warranted for each class of customers. A comparison of the allocated cost to serve a class of customers and the actual revenues received from that class is taken into consideration during rate design.

Functionalization of Costs

Salem's Test Year electric revenue requirements have been divided into four functional categories. These categories are described below.

Power Supply – the power supply function is related to the cost of Salem transmission and purchases of wholesale power through UMPA and Southern Utah Valley Power.

Distribution – distribution expenses are related to the Salem owned system for delivering power and energy to Salem customers. They include local substation and distribution system costs.

Customer – these costs are fixed costs associated with the service facilities utilized to deliver electric power and energy directly to customers. They also include items such as meter reading, billing, collections and dealing with customers by customer service representatives.

Revenue – revenue related costs include transfers to the City and City related fees, other operating and non-operating income and utility margin.

Table 3-1 below summarizes the functional electric costs for the 2015 Test Year. The detailed cost functions are shown in Exhibit 3-A.

Table 3-1
Functional Electric Costs
2015 Test Year

Component	Revenue Requirement
Power Supply	$2,362,328
Distribution	597,197
Customer	45,845
Revenue	274,279
Total	$3,279,649

Classification of Costs

Within each function, the revenue requirements have been divided into distinct cost classifications. These cost classifications are described below.

Demand Related – demand related costs are fixed costs that do not vary with hourly consumption. Demand related costs are required to meet the overall demand of the system as expressed in kW.

Energy Related – energy related costs vary based on hourly consumption in kWh.

Customer Related – costs related to serving, metering and billing of individual customers.

Revenue Related – revenue related costs vary by the amount of revenue received by the utility.

Exhibits 3-B through 3-D show the detailed classification of revenue requirements within the functions.

Allocation of Costs

Based on an analysis of customer class service characteristics, the classified costs summarized above were allocated to the major Salem customer classes. Allocation of costs was performed on a fully-distributed, embedded cost allocation basis. Specific allocation factors were utilized in each of the cost classification categories as described below. Exhibit 3-E contains a summary of the development of the various allocation factors.

Demand Allocations

Customer class demands on a system can be reflected in various ways. Two primary demand allocation types were utilized in this analysis. A common industry allocator known as Coincident Peak Demand (CP) allocator is utilized to allocate demand related costs based on each class' contribution to the system peak demand each month. A 12 CP demand allocator was utilized for power supply related demand costs. A Non-coincident Peak Demand (NCP) reflects a class maximum demand regardless of when it occurs. A 1 NCP method, an estimate of each class' maximum annual demand on the system, was utilized for allocating local system demand related costs.

Energy Allocations

Each class' share of energy requirements was used to allocate energy related costs. The predominant energy related costs are the energy portions of the purchased power expenses. These costs were allocated based on each class' estimated share of wholesale energy purchases, this is referred to as the Net Energy for Load (NEFL) allocator.

Customer Allocations

Two separate customer allocators were utilized. The customer distribution allocator was used to allocate costs associated with the physical facilities required to serve individual customers. The customer service allocator is for allocation of costs associated with customer service – meter reading, billing, collections and customer inquiries. For both the customer distribution and customer service allocators, a weighted customer allocation factor is developed. Weighting factors are developed to represent the difference in service configurations between customer classifications. For instance, a larger customer facility is required for a single large power customer than for a single residential customer, or a single large power customer requires more customer service than a single residential customer.

Revenue Allocations

Revenue related costs were allocated based on each class' share of total demand, energy, customer distribution, customer service and direct costs.

Cost of Service Results

Based on the classifications and allocations described above, the estimated cost to serve each major class of customers for the 2015 Adjusted Test Year was determined. Exhibit 3-F presents this analysis in detail. Table 3-2 below summarizes the total allocated electric costs for each class compared to the total electric revenues received from the class during 2015.

Table 3-2
Electric Cost of Service Results
Comparison of Cost and Revenues
2015 Test Year

Customer Classification	Allocated Cost to Serve	Revenues
Residential	$2,168,596	$2,096,401
Commercial no Demand	50,282	52,579
Commercial with Demand	983,368	1,079,696
Industrial	77,403	50,975
Total	$3,279,649	$3,279,649

The revenue requirements and revenues as allocated to each class and summarized above are shown on a total dollars basis. Table 3-3 below makes the comparison based on percentages of total cost to serve and total revenues. The percentage increase/(decrease) in each class' revenue shown below is the adjustment necessary to produce revenues from each class in accordance with the allocated cost to serve. The percentage adjustments do not represent the recommended change in each class' rates. The cost-of-service results are one item for consideration in rate design. It is important to note also that the adjustments shown in the table below would not change the total revenue received by the utility and are not indicative of overall revenue needs of the utility going forward. Recommendations regarding rate design are included in Section 4 of this report.

Table 3-3
Electric Cost of Service Results
Comparison of % Cost and Revenues
2015 Test Year

Customer Classification	Allocated Cost to Serve	Revenues	Increase/ (Decrease)
Residential	66.1%	63.9%	3.4%
Commercial no Demand	1.5%	1.6%	-4.4%
Commercial with Demand	30.0%	32.9%	-8.9%
Industrial	2.4%	1.6%	51.8%
Total	100.0%	100.0%	0.0%

As indicated above, Salem's existing class revenues do not exactly match the allocated cost to serve each class. Cost based rates are one of several goals in establishing rates. The relationship between allocated costs and revenues for each class should be considered, in addition to other rate related goals, in developing recommended rates. Small classes of customers often do not lend themselves well to an overall COS analysis, the comparison shown above for the industrial class should not be considered to be entirely indicative of the appropriate rate levels for that class.

Per Unit Costs

Based on the cost-of-service results shown above, the costs have been summarized on a per unit basis by customer class and class billing data. These per unit costs resemble rates and represent another piece of information for use in rate design. The resulting per unit costs by rate class are shown in Table 3-4

Table 3-4
Per Unit Electric Costs
2015 Test Year

Customer Classification	Total		
	Dmd ($/kW)	Energy ($/kWh)	Cust ($/mo)
Residential	$8.43	$0.03711	$8.94
Commercial no Demand	$9.06	$0.03711	$8.94
Commercial with Demand	$10.80	$0.03711	$32.25
Industrial	$16.44	$0.03614	$233.16

Functional Unbundling

Line	Description	2015	Adjustments	Test Year	Allocation	Power Supply	Distribution	Customer	Revenue	Total
1	**Power Production and Delivery Expense**									
2	Salaries	392,309		392,309	Distribution	-	392,309	-	-	392,309
3	Employee Benefits	197,581		197,581	Distribution	-	197,581	-	-	197,581
4	Clothing Allowance	3,831		3,831	Distribution	-	3,831	-	-	3,831
5	Safety Equipment/Testing	12,424		12,424	Distribution	-	12,424	-	-	12,424
6	Power System Maint & Repair	47,107		47,107	Distribution	-	47,107	-	-	47,107
7	Equip Supplies/Inventory	31,840		31,840	Distribution	-	31,840	-	-	31,840
8	Substation Repair	13,459		13,459	Distribution	-	13,459	-	-	13,459
9	Professionals & Technical	25,365		25,365	Distribution	-	25,365	-	-	25,365
10	Travel/Education	5,384		5,384	Distribution	-	5,384	-	-	5,384
11	Power Purchased UMPA	2,261,023		2,261,023	Power Supply	2,261,023	-	-	-	2,261,023
12	UMPA SCADA	3,769		3,769	Power Supply	3,769	-	-	-	3,769
13	SUVP Payments	96,511		96,511	Power Supply	96,511	-	-	-	96,511
14	Capital Outlay/Substation	46,590		46,590	Distribution	-	46,590	-	-	46,590
15	Equipment Purchase	10,353		10,353	Distribution	-	10,353	-	-	10,353
16	Motor Pool	30,128		30,128	Distribution	-	30,128	-	-	30,128
17	Depreciation Expense	209,835		209,835	O&M x/PS	-	202,731	7,104	-	209,835
18	**Total Power Production and Delivery**	**3,387,508**	**-**	**3,387,508**		**2,361,302**	**1,019,102**	**7,104**	**-**	**3,387,508**
19										
20	**Administrative & General**									
21	Meter Reader Salaries	7,798		7,798	Customer	-	-	7,798	-	7,798
22	Employee Benefits	429		429	Customer	-	-	429	-	429
23	Office Exp & Supplies	518		518	Customer	-	-	518	-	518
24	Administrative Services	290,740		290,740	O&M x/PP	1,026	279,906	9,808	-	290,740
25	Substation O&M	9,318		9,318	Distribution	-	9,318	-	-	9,318
26	Public Safety Vehicle Fund	6,730		6,730	Customer	-	-	6,730	-	6,730
27	Transfer Funds to Motor Pool	13,459		13,459	Customer	-	-	13,459	-	13,459
28	**Total Administrative & General**	**328,991**	**-**	**328,991**		**1,026**	**289,223**	**38,741**	**-**	**328,991**
29										
30	**Other Expenses (Revenues)**									
31	Impact Fees	(179,431)		(179,431)	Distribution	-	(179,431)	-	-	(179,431)
32	Electric Hookup Fees	(23,417)		(23,417)	Distribution	-	(23,417)	-	-	(23,417)
33	Reconnect Fee	(1,500)		(1,500)	Distribution	-	(1,500)	-	-	(1,500)
34	Power Hook Up New Subdivision	(466,967)		(466,967)	Distribution	-	(466,967)	-	-	(466,967)

Functional Unbundling

Line	Description	2015	Adjustments	Test Year	Allocation	Power Supply	Distribution	Customer	Revenue	Total
35	Other Revenues	(39,814)		(39,814)	Distribution	-	(39,814)	-	-	(39,814)
36	Transfer Funds to General Fund	305,004		305,004	Revenue	-	-	-	305,004	305,004
37	Utility Margin	(30,725)		(30,725)	Revenue	-	-	-	(30,725)	(30,725)
38	**Total Other Expenses (Revenues)**	**(436,850)**	**-**	**(436,850)**		**-**	**(711,129)**	**-**	**274,279**	**(436,850)**
39										
40	**Total Revenue Requirement**	**3,279,649**		**3,279,649**		**2,362,328**	**597,197**	**45,845**	**274,279**	**3,279,649**

Power Supply

Line	Description	Test Year	Allocation	Demand	Energy	Total
1	**Operating Expenses**					
2	Salaries	-	Demand	-	-	-
3	Employee Benefits	-	Demand	-	-	-
4	Clothing Allowance	-	Demand	-	-	-
5	Safety Equipment/Testing	-	NA	-	-	-
6	Power System Maint & Repair	-	NA	-	-	-
7	Equip Supplies/Inventory	-	NA	-	-	-
8	Substation Repair	-	NA	-	-	-
9	Professionals & Technical	-	NA	-	-	-
10	Travel/Education	-	NA	-	-	-
11	Power Purchased UMPA	2,261,023	UMPA	1,164,826	1,096,197	2,261,023
12	UMPA SCADA	3,769	Demand	3,769	-	3,769
13	SUVP Payments	96,511	Demand	96,511	-	96,511
14	Capital Outlay/Substation	-	NA	-	-	-
15	Equipment Purchase	-	NA	-	-	-
16	Motor Pool	-	NA	-	-	-
17	Depreciation Expense	-	NA	-	-	-
18	**Total**	**2,361,302**		**1,265,105**	**1,096,197**	**2,361,302**
19						
20	**Administrative & General**					
21	Meter Reader Salaries	-	NA	-	-	-
22	Employee Benefits	-	NA	-	-	-
23	Office Exp & Supplies	-	NA	-	-	-
24	Administrative Services	1,026	Demand	1,026	-	1,026
25	Substation O&M	-	NA	-	-	-
26	Public Safety Vehicle Fund	-	NA	-	-	-
27	Transfer Funds to Motor Pool	-	NA	-	-	-
28	**Total Administrative & General**	**1,026**		**1,026**	**-**	**1,026**

Power Supply

Line	Description	Test Year	Allocation	Demand	Energy	Total
29						
30	**Other Expenses (Revenues)**					
31	Impact Fees	-	NA	-	-	-
32	Electric Hookup Fees	-	NA	-	-	-
33	Reconnect Fee	-	NA	-	-	-
34	Power Hook Up New Subdivision	-	NA	-	-	-
35	Other Revenues	-	NA	-	-	-
36	Transfer Funds to General Fund	-	NA	-	-	-
37	Utility Margin	-	NA	-	-	-
37	**Total Other Expenses (Revenues)**	**-**		**-**	**-**	**-**
38						
39	**Total Revenue Requirement**	**2,362,328**		**1,266,131**	**1,096,197**	**2,362,328**

Distribution

Line	Description	Test Year	Allocation	Demand	Customer	Total
1	**Operating Expenses**					
2	Salaries	392,309	O&M	308,550	83,759	392,309
3	Employee Benefits	197,581	O&M	155,397	42,184	197,581
4	Clothing Allowance	3,831	O&M	3,013	818	3,831
5	Safety Equipment/Testing	12,424	O&M	9,771	2,653	12,424
6	Power System Maint & Repair	47,107	PIS	25,021	22,086	47,107
7	Equip Supplies/Inventory	31,840	PIS	16,912	14,928	31,840
8	Substation Repair	13,459	Demand	13,459	-	13,459
9	Professionals & Technical	25,365	O&M	19,950	5,416	25,365
10	Travel/Education	5,384	O&M	4,234	1,149	5,384
11	Power Purchased UMPA	-	NA	-	-	-
12	UMPA SCADA	-	NA	-	-	-
13	SUVP Payments	-	NA	-	-	-
14	Capital Outlay/Substation	46,590	Demand	46,590	-	46,590
15	Equipment Purchase	10,353	PIS	5,499	4,854	10,353
16	Motor Pool	30,128	O&M	23,696	6,432	30,128
17	Depreciation Expense	202,731	PIS	107,680	95,051	202,731
18	**Total**	**1,019,102**		**739,772**	**279,330**	**1,019,102**
19						
20	**Administrative & General**					
21	Meter Reader Salaries	-	NA	-	-	-
22	Employee Benefits	-	NA	-	-	-
23	Office Exp & Supplies	-	NA	-	-	-
24	Administrative Services	279,906	Demand	279,906	-	279,906
25	Substation O&M	9,318	Demand	9,318	-	9,318
26	Public Safety Vehicle Fund	-	NA	-	-	-
27	Transfer Funds to Motor Pool	-	NA	-	-	-
28	**Total Administrative & General**	**289,223**		**289,223**	**-**	**289,223**

Distribution

Line	Description	Test Year	Allocation	Demand	Customer	Total
29						
30	**Other Expenses (Revenues)**					
31	Impact Fees	(179,431)	O&M	(141,122)	(38,309)	(179,431)
32	Electric Hookup Fees	(23,417)	Customer	-	(23,417)	(23,417)
33	Reconnect Fee	(1,500)	Customer	-	(1,500)	(1,500)
34	Power Hook Up New Subdivision	(466,967)	Demand	(466,967)	-	(466,967)
35	Other Revenues	(39,814)	Demand	(39,814)	-	(39,814)
36	Transfer Funds to General Fund	-	NA	-	-	-
37	Utility Margin	-	NA	-	-	-
37	**Total Other Expenses (Revenues)**	**(711,129)**		**(647,903)**	**(63,226)**	**(711,129)**
38						
39	**Total Revenue Requirement**	**597,197**		**381,093**	**216,104**	**597,197**

Customer

Line	Description	Test Year	Allocation	Customer	Total
1	**Operating Expenses**				
2	Salaries	-	Customer	-	-
3	Employee Benefits	-	Customer	-	-
4	Clothing Allowance	-	Customer	-	-
5	Safety Equipment/Testing	-	NA	-	-
6	Power System Maint & Repair	-	NA	-	-
7	Equip Supplies/Inventory	-	NA	-	-
8	Substation Repair	-	NA	-	-
9	Professionals & Technical	-	NA	-	-
10	Travel/Education	-	NA	-	-
11	Power Purchased UMPA	-	NA	-	-
12	UMPA SCADA	-	NA	-	-
13	SUVP Payments	-	NA	-	-
14	Capital Outlay/Substation	-	NA	-	-
15	Equipment Purchase	-	NA	-	-
16	Motor Pool	-	NA	-	-
17	Depreciation Expense	7,104	Customer	7,104	7,104
18	**Total**	**7,104**		**7,104**	**7,104**
19					
20	**Administrative & General**				
21	Meter Reader Salaries	7,798	Customer	7,798	7,798
22	Employee Benefits	429	Customer	429	429
23	Office Exp & Supplies	518	Customer	518	518
24	Administrative Services	9,808	Customer	9,808	9,808
25	Substation O&M	-	NA	-	-
26	Public Safety Vehicle Fund	6,730	Customer	6,730	6,730
27	Transfer Funds to Motor Pool	13,459	Customer	13,459	13,459
28	**Total Administrative & General**	**38,741**		**38,741**	**38,741**

Customer

Line	Description	Test Year	Allocation	Customer	Total
29					
30	**Other Expenses (Revenues)**				
31	Impact Fees	-	NA	-	-
32	Electric Hookup Fees	-	NA	-	-
33	Reconnect Fee	-	NA	-	-
34	Power Hook Up New Subdivision	-	NA	-	-
35	Other Revenues	-	NA	-	-
36	Transfer Funds to General Fund	-	NA	-	-
37	Utility Margin	-	NA	-	-
38	**Total Other Expenses (Revenues)**	**-**		**-**	**-**
39					
40	**Total Revenue Requirement**	**45,845**		**45,845**	**45,845**

Exhibit 3-E

Cost of Service

Line	Description	Test Year	Allocation	Residential	Commercial No Demand	Commercial with Demand	Industrial	Total
36	Allocation Factors							
37								
38				42,105	946	20,602	1,495	65,148
39	12 Coincident Peak Demand		12CP	65%	1%	32%	2%	100%
40				8,144	203	2,284	215	10,846
41	1 Non-Coincident Peak Demand for Distribution		1NCP	75%	2%	21%	2%	100%
42				142,973	3,074	48,586	2,430	197,063
43	Sum of Maximum Demands		SMD	73%	2%	25%	1%	100%
44				20,181,362	425,650	10,666,822	982,800	32,256,634
45	kWh Sales		kWh Sales	63%	1%	33%	3%	100%
46				21,899,798	461,894	11,575,098	1,038,367	34,975,157
47	Net Energy for Load		NEFL	63%	1%	33%	3%	100%
48				23,904	723	1,953	12	26,592
49	Count of Meter Months		Meters	90%	3%	7%	0%	100%
50				23,904	723	7,812	360	32,799
51	Customers - Distribution Weighting		Cust. Distribution	73%	2%	24%	1%	100%
52				23,904	723	3,906	120	28,653
53	Customers - Customer Service Weighting		Cust. Service	83%	3%	14%	0%	100%
54				1,014,048	24,298	458,109	31,624	1,528,080
55	Revenue Requirement		RevReq	66%	2%	30%	2%	100%

Cost of Service

Line	Description	Test Year	Allocation	Residential	Commercial No Demand	Commercial with Demand	Industrial	Total
1	**Power Supply**							
2	Power Supply Demand Expense	1,266,131	12CP	818,304	18,378	400,389	29,060	1,266,131
3	Power Supply Energy Expense	1,096,197	NEFL	686,387	14,477	362,789	32,545	1,096,197
4	**Total Power Supply**	2,362,328		1,504,692	32,854	763,177	61,605	2,362,328
5								
6	**Distribution**							
7	Distribution Demand Expense	381,093	1NCP	286,146	7,145	80,243	7,558	381,093
8	Distribution Customer Expense	216,104	Cust. Distribution	157,497	4,764	51,471	2,372	216,104
	Total Transmission & Distribution	597,197		443,644	11,909	131,714	9,930	597,197
9								
10								
11	**Customer**							
12	Customer Service and Account	45,845	Cust. Service	38,247	1,157	6,250	192	45,845
13	**Total Customer**	45,845		38,247	1,157	6,250	192	45,845
14								
15	**Revenue**							
16	Revenue Expense	274,279	RevReq	182,014	4,361	82,227	5,676	274,279
17	**Total Revenue**	274,279		182,014	4,361	82,227	5,676	274,279
18								
19	**Total Cost of Service**	**3,279,649**		**2,168,596**	**50,282**	**983,368**	**77,403**	**3,279,649**
21								
22	Percent of Cost of Service	100%		66.1%	1.5%	30.0%	2.4%	100.0%
23	Percent of Revenue	100%		63.9%	1.6%	32.9%	1.6%	100.0%
24	Difference	0%		3.4%	-4.4%	-8.9%	51.8%	0.0%
25								
26	Classified Cost of Service							
27	Customer Cost	285,856		213,608	6,461	62,989	2,798	285,856
28	Demand Cost	1,797,554		1,205,246	27,852	524,495	39,960	1,797,554
29	Energy Cost	1,196,240		749,029	15,798	395,898	35,515	1,196,240
30								
31	Classified Unit Cost of Service							
32	Customer Cost	10.75		8.94	8.94	32.25	233.16	10.75
33	Demand Cost	9.12		8.43	9.06	10.80	16.44	9.12
34	Energy Cost	0.03709		0.03711	0.03711	0.03711	0.03614	0.03709

Section 4
Proposed Rates

Changes to rates are generally based on the overall need for revenues and results of the cost-of-service analyses. The projected operating results at existing rates as presented in Section 2 of this report outlines the overall revenue needs of the electric utility. Section 3 summarizes the cost-of-service results. These factors have been considered in developing the proposed rates summarized in this section of the report.

Proposed Rates

Revenue Needs

In Section 2, it shows that Salem's projected annual change in net position declines from negative 5.8% of revenues in FY 2016 to negative 7.5% of revenues in FY 2020. Additionally, Salem's projected cash reserves at current rates are expected to decrease from $490,957 at the end of FY 2016 to $160,583 at the end of FY 2020. The end of the Study Period projected reserves are less than 4% of annual revenues. Based on these projected results, a 4.2% increase in utility revenues through rates is recommended. Our recommended rate adjustments by class are shown in Exhibit 4-A.

Rate Design Adjustments

The cost of service analysis summarized in Section 3 shows that the Commercial with Demand and, to a lesser extent, Commercial without Demand are providing a subsidy to the Residential and Industrial classes. As Salem requires future rate adjustments, it may wish to consider implementing a higher increase for Residential and Industrial customers and a lower increase for Commercial without Demand and Commercial with Demand customers.

For Residential customers, Salem has a few customers with 400 amp services to their homes. The standard service size in Salem is 200 amps for a residential customer. Customers with larger service sizes place more fixed costs on the system. We have proposed a new rate class 102 for 400 amp and higher residential customers, for this rate the monthly charge is increased from $11 to $20, the rest of the rate is identical to the regular residential rate.

After reviewing Salem's current rate structures, we recommend adjustments be considered to the inclining block rate structure for classes with demand charges. For those customer classes with a demand charge, including an inclining block energy rate in the rate structure unduly penalizes customers based solely on their size while the per kWh cost to service a customer does not necessarily increase with size. Typically, inclining rate blocks are introduced to encourage energy efficiency. However, because the Commercial with Demand class serves a wide variety of customers at various sizes, the selection of block sizes using a fixed kWh usage that effectively sends a pricing signal to efficiently use energy is not possible. For example, any customer that uses less than 3,000 kWh/month under the current Commercial with Demand rate receives no pricing signal and receives a lower energy rate just for being small. Conversely, customers that use significantly more than 3,000 kWh/month may be so far removed from the pricing point that they do not have any opportunity to react to the pricing signal. Additionally, a demand and energy rate is designed to promote efficient use of fixed system investments, customers with higher load factors (energy use relative to demand) pay a lower overall average per kWh. For customers like these, efficient use of the system is more important than size. However, the existence of the lower first block of energy provides some rate related relief for smaller customers given the $49 per month customer charge. This monthly charge is relatively high for small Commercial customers; the lower first block of energy helps counter the customer charge for smaller customers. We have provided two alternatives for proposed rates for the Commercial with Demand class. The first option removes the tiered energy rate design and replaces it with a single energy charge in combination with the demand charge. The second option, labeled 'Alternative', maintains the current design to provide a slightly lower energy rate to smaller customers in this class.

For the Industrial class, we recommend the inclining block energy rate design be replaced by a single energy block. Additionally, we recommend that the demand rate in the Industrial class be increased. Currently, the Commercial with Demand and Industrial rates have the same $10.99 demand rate. However, the Industrial rate energy rates are lower than the Commercial with Demand rate. This difference is not warranted by the costs to serve. We initially recommend a $0.50 increase in the Industrial demand rate with additional increases in this component of the rate as additional utility revenues are needed.

Projected Operating Results – Proposed Rates

The rates recommended for Salem increase overall projected revenues for Salem beginning in FY 2017. Table 4-1 below summarizes the revised projected operating results with a July 1, 2016 rate increase.

Table 4-1
Projected Operating Results
New July 1, 2016 Rates

Year	2016	2017	2018	2019	2020
Operating Revenues	$3,678,324	$4,237,469	$4,308,589	$4,385,072	$4,463,788
Less Operating Expenses	(3,592,465)	(3,939,792)	(4,066,696)	(4,197,423)	(4,314,866)
Plus Non-Operating Revenues	40,012	40,892	41,792	42,711	43,651
Less City Transfers	(338,686)	(338,686)	(338,686)	(338,686)	(338,686)
Change in Net Position	($212,815)	($102)	($54,987)	($108,312)	($146,113)
Net Position as Percent of Revenues	-5.8%	0.0%	-1.3%	-2.5%	-3.3%

Cash Reserves – Proposed Rates

A summary of the impact of the proposed rates on Salem's cash reserves for the Study Period is shown in Table 4-2 below.

As shown below, the proposed rates increase the estimated end of study period cash reserve level from $160,583 under existing retail rates to $842,092 under the proposed rates. This represents an increase from 4% of revenues under existing rates to 19% of revenues under the proposed rates at the end of FY 2020. We would recommend that Salem set a goal of a minimum level of cash reserves equal to 25% of revenues. In order to achieve that level, Salem may wish to implement additional rate adjustments during the Study Period.

Table 4-2
Projected Cash Reserves
New July 1, 2016 Rates

Year	2016	2017	2018	2019	2020
Beginning Balance	$533,276	$490,957	$661,576	$772,696	$826,029
Plus Change in Net Position	(212,815)	(102)	(54,987)	(108,312)	(146,113)
Plus Depreciation	210,502	211,168	212,002	213,002	214,002
Less Capital Improvements	(20,000)	(20,000)	(25,000)	(30,000)	(30,000)
Less Debt Principal	($20,006)	($20,446)	($20,896)	($21,356)	($21,825)
Ending Balance	$490,957	$661,576	$772,696	$826,029	$842,092
Reserves as % of Revenue	13%	16%	18%	19%	19%

Net Metering

Based on the analyses contained in this study, we have identified several options for Salem's consideration relative to rate provisions applicable to net metering of small distributed generation facilities at customer locations, most notably solar power installations. Net metering is a billing mechanism where customers with distributed generation (like rooftop solar) are credited for electricity they deliver back to the distribution system. For example, if a residential customer has a solar system on the home's rooftop, it may generate more electricity than the home uses during daylight hours. If the home is net-metered, the utility pays the customer for the excess generation. The rate paid for the excess generation varies by state and utility.

The State of Utah net metering policy requires Rocky Mountain Power and all rural electric cooperatives to offer a net metering tariff to their customers. However, municipally owned utilities like Salem are not currently required to offer net metering, but they may if they desire. Salem's current net metering policy is to apply net metering to the standard tariff for users with less than 25kW of generation. Under the current Salem net metering rate, a customer receives full retail price credit for energy it delivers to the utility during periods when the on-site generator is producing more energy than the customer requires. The customer can apply that payment/credit to its usage during times that the on-site generator is not producing energy. Any excess generation (negative net energy) is not rolled over from month to month.

Within the electric industry, there are numerous discussions about the economic and operational ‘fairness’ of net metering programs. Distributed generation advocates argue that net metering programs help promote this beneficial program. Others argue that net metering customers do not contribute sufficiently to the fixed cost of the electric grid, resulting in subsidies from non-net metering customers. There are several potential rate approaches addressing the need for net metering customers to make a contribution to the fixed costs of the grid, even if their net use of energy during a billing period may be zero. Based on the results of the cost-of-service study, we have examined the following rate scenarios and have designed cost based rates for your consideration. It should be noted that due to the incompatibility of inclining block tiered rates with net metering, all designed cost based rates include only a single energy charge as opposed to the tired rate structure of the general tariff.

- Current net metering policy
- Higher monthly customer charge
- Retail demand charge rate structure
- Separate charge based on solar generating capacity
- Minimum bill provision
- Feed-in-tariff

These options are discussed below.

Current Net Metering Policy

Salem could opt to maintain its current net metering policy. It is similar to standard net metering policies in place at numerous utilities nationwide. It also reflects current Utah requirements on Rocky Mountain Power and cooperatives. The current policy does not address cost based concerns about potential subsidies from regular customers to net metering customers.

Higher monthly customer charge

Credits that net metering customers receive for power generated do not generally apply to the fixed monthly customer charge paid by customers. The fixed charge does not vary based on energy used by a customer. Customer charges are meant to recover fixed charges incurred by the utility simply by having a customer connected to the system. These can include meter reading, billing and customer services. They may also include fixed system costs such as portions of the distribution system, service transformers, service lines and meter installations. A higher customer charge can be designed to collect some or all of a customers allocated fixed costs of the local system. This rate design alternative could be applied to all customers or to just net metering customers.

Retail demand charge rate structure

Solar net metering customers purchase less net energy from the utility while still placing demands on the system during times when the solar units are not generating (evenings/nights). This results in net metering customers having a much lower effective load factor for their service. Under a customer charge/energy charge rate structure, it is not possible to adjust rates to reflect wide disparities in load factor. Moving residential net metering customers to a demand and energy rate structure as is commonly done for non-residential customers can allow for contribution to fixed system charges by these customers despite their low energy use.

Separate charge based on solar generating capacity

Net metering customers access the distribution system to deliver energy to the utility during over generation periods and to receive energy during low generation periods. Based on the size of the solar generation installation, a separate distribution access fee can be charged to a customer. This charge is levied on a $/kW basis to reflect the fixed expense of the distribution system. The charge can either be assessed on the total generation size or the generation size less the average demand of a typical residential customer. For Salem, the average residential customer is estimated to have an average monthly peak demand of 6 kW. As an example, a solar customer with an 8 kW system, they could be charged for the full 8 kW of demand or for 2 kW (8 kW generator capacity less the 6 kW average customer demand).

Minimum bill provision

Implementation of a simple minimum bill provision can ensure that net metering customers, as well as all customers, make a minimum contribution to system fixed costs.

Feed-in-tariff

Feed-in-tariffs are designed to pay for output of distributed generation at a 'value of solar' rate. There is often discussion regarding what the value of solar should include relative to generation, transmission, distribution, environmental externalities and other costs. For our analysis, we have assumed a value equal to the avoided average generation cost for Salem. Under this type of scenario, the output that is exported to the system by the generator is not paid the full retail rate in a net metering arrangement. The customer receives a credit for the excess generation based on the feed in tariff rate.

A proposed rate is shown in the following table for each of the rate arrangements discussed above. These are cost based rates based on the FY 2015 test year included in the rate study. The footnotes contain a brief explanation of the basis for the calculations.

Net Metering Alternatives

FY 2015 Test Year

Item	Rate
Current net metering policy[(1)]	Current rate
Higher monthly customer charge[(2)]	$27.77/mo. $0.07456/kWh
Retail demand charge[(3)]	$8.94/mo cust $8.43/kW-mo demand $0.03711/kWh energy
Separate charge based on solar capacity[(4)]	$3.10/kW-mo
Minimum bill provision[(5)]	$27.77/mo.
Feed-in-tariff[(6)]	$0.07456/kWh

(1) No change in current rate policy
(2) Customer unit cost plus distribution fixed cost for average customer plus production costs in energy.
(3) Cost based three-part rate for all services.
(4) Distribution fixed cost per kW.
(5) Equals higher customer charge computation.
(6) Allocated residential production cost.

Proposed Rates

	Rates Current	Rates Proposed	
Rate 101 - Residential City			
Customer Service Charge ($/Month)	11.00	11.00	
Energy Charge ($/kWh)			
Tier 1 (First 500kWh)	0.08389	0.08793	
Tier 2 (501-999kWh)	0.09844	0.10318	
Tier 3 (1000kWh)	1.50	1.50	
Tier 4 (1001-1499kWh)	0.11752	0.12318	
Tier 5 (1500kWh)	2.50	2.50	
Tier 6 (All additional kWh)	0.12532	0.13136	
Rate 102 - Residential City - 400 amp service		new rate	
Customer Service Charge ($/Month)	n/a	20.00	
Energy Charge ($/kWh)			
Tier 1 (First 500kWh)	n/a	0.08793	
Tier 2 (501-999kWh)	n/a	0.10318	
Tier 3 (1000kWh)	n/a	1.50	
Tier 4 (1001-1499kWh)	n/a	0.12318	
Tier 5 (1500kWh)	n/a	2.50	
Tier 6 (All additional kWh)	n/a	0.13136	
Rate 103 - Residential County			
Customer Service Charge ($/Month)	11.00	11.00	
Energy Charge ($/kWh)			
Tier 1 (First 500kWh)	0.09395412	0.098479	
Tier 2 (501-999kWh)	0.10224864	0.107173	
Tier 3 (1000kWh)	1.56	1.56	
Tier 4 (1001-1499kWh)	0.12209600	0.127977	
Tier 5 (1500kWh)	2.6	2.60	
Tier 6 (All additional kWh)	0.13020800	0.136479	
Rate 106 - Commercial without Demand			
Customer Service Charge ($/Month)	20.00	20.00	
Energy Charge ($/kWh)			
Tier 1 (First 700kWh)	0.075280	0.079390	
Tier 2 (All additional kWh)	0.113085	0.119259	
Rate 107 - Commercial County without Demand			
Customer Service Charge ($/Month)	20.00	20.00	
Energy Charge ($/kWh)			
Tier 1 (First 700kWh)	0.085512	0.090500	
Tier 2 (All additional kWh)	0.128455	0.135469	
Rate 108 - Commercial with Demand			Alternative
Customer Service Charge ($/Month)	49.00	49.00	49.00
Demand Charge ($/kW)	10.99	10.99	10.99
Energy Charge ($/kWh)			
Tier 1 (First 3000kWh)	0.03473	0.04828	0.03798
Tier 2 (All additional kWh)	0.04750	0.04828	0.05194
Rate 110 - Industrial Rate			
Customer Service Charge ($/Month)	110.00	110.00	
Demand Charge ($/kW)	10.99	11.49	
Energy Charge ($/kWh)			
Tier 1 (First 1000kWh)	0.02857	0.03443	
Tier 2 (All additional kWh)	0.03090	0.03443	

RESOLUTION_______

ROLL CALL

VOTING	YES	NO
RANDY A. BRAILSFORD Mayor (votes only in case of tie)		
SOREN CHRISTENSEN City Council Member		
AARON D. CLOWARD City Council Member		
STERLING M. REES City Council Member		
CRISTY SIMONS City Council Member		
CRAIG B. WARREN City Council Member		

I MOVE this resolution be adopted: ___________________________
City Council Member

I SECOND the foregoing motion: ___________________________
City Council Member

RESOLUTION __________

A RESOLUTION AMENDING ELECTRIC UTILITY RATES

WHEREAS, Salem City owns and operates its own electric power distribution system; and

WHEREAS, the City must generate sufficient revenue from its electric rates to purchase the power it buys and also to provide for operation and maintenance of the system; and

WHEREAS, power costs have risen in recent years and additional sources of electric power are needed to meet the needs of a growing population; and

WHEREAS, as a member of Utah Municipal Power Agency (UMPA), Salem has been able to hold rates below the inflation rate and has rarely adjusted electric rates; and

WHEREAS, solar power is becoming more economical and should be encouraged, but those users shouldn't be subsidized by those who choose not to, or cannot afford the capital investment, to purchase solar panels; and

WHEREAS, solar panel users can't generate electric power when the sun is not shining, but still need electricity during those times, causing the City to still generate or purchase power and maintain the system for their benefit; and

WHEREAS, UMPA has hired a consultant for its members to conduct a detailed rate study to assist each member to create a rate structure for its specific needs and which is fair and equitable to all consumers;

NOW THEREFORE, be it resolved by the Salem City Council as follows:

1. Each residential electric customer up to a 400 amp service shall pay a customer service charge of $11.00 per month, plus a usage charge as set forth herein.

2. Each residential electric customer with a 400 amp service or larger shall pay a customer service charge of $20.00 per month, plus a usage charge as set forth herein.

3. The electric power usage rate for all residential customers within Salem City is shown in the following table:

kWh Usage	Rate per kWh
first 500 kWh	.08739
501 - 999	.10318
1000	1.50
1001 - 1499	.12318
1500	2.50
over 1500	.13136

4. The electric power usage rate for all residential customers without Salem City

(County residents) is shown in the following table:

kWh Usage	Rate per kWh
first 500	.098479
501 - 999	.107173
1000	1.56
1001 - 1499	.127977
1500	2.60
over 1500	.136479

5. Each commercial electric customer without a demand charge shall pay a customer service charge of $20.00 per month, plus a usage charge as shown in the following table:

kWh Usage	Rate per kWh
first 700	.07939 (within City limits)
first 700	.0905 (without City limits)
over 700	.119259 (within City limits)
over 700	.135469 (without City limits)

6. Each commercial electric customer with a demand charge shall pay a customer service charge of $49.00 per month and a demand charge of $10.99 per kW, plus a usage charge as shown in the following table:

kWh Usage	Rate per kWh
first 3000	.03798
over 3000	.05194

7. Each industrial electric customer shall pay a customer service charge of $110.00 per month and a demand charge of $11.49 per kW, plus a usage charge of .03443 per kWh.

8. Customers using their own solar panels shall pay $3.10 per kW based on capacity of

~~generated by~~ their solar panels, plus the customer service charge, usage rate, and demand charge, if applicable, for their respective class.

9. This resolution repeals all prior resolutions which establish electric rates. All existing due dates, late charges and other rules and regulations relating to power rates shall remain in effect and are not modified by this resolution.

6. This resolution is effective August 1, 2016.

DATED this ______ of July, 2016

____
RANDY A. BRAILSFORD, Mayor

Attest:

____
JEFFREY D. NIELSON, City Recorder

SALEM CITY
Staff Report to Mayor & City Council

Agenda Date:	**August 23, 2016**
Agenda Item #:	**Sewer Plant Baldor Motor**
Staff Contacts:	Matt Marziale

Background Discussion: This motor is used in our sewer lagoons. The Baldor is place in our lagoons to supply aeration. This is the Motor that pushes the water on our ponds. Need to add aeration to the pond to help decomposition process. This motor is a special sewer use motor and not found at large retailers or local store fronts.

Bid information: Bisco - $6251.55
Energy Management - $6363.65
Red Rhino - decided to bid.

Recommendation: Salem Public Works recommend to accept the bid of Bisco.

Budgetary Impact: This is a budgeted item.

Attachments: Bisco Bid - Energy Management bids.

ENERGY MANAGEMENT CORPORATION

501 West 700 South
Salt Lake City, UT 84101
801-366-4100

QUOTATION

Quote Number: 91389
Quote Date: 08/08/16
Page: 1
Customer Phone:
Customer Email:
ENERGY MANAGEMENT CORP.

Quote: SALEM CITY CORPORATION
PO BOX 901
-
SALEM, UT 84653

SHIP: SALEM CITY CORPORATION
-
SALEM, UT 84653

Taxable: No
Pmt Terms: Net 30 (OAC)
Cust Code: SALCIT

RFQ#:
Ship Via: WILL CALL
Quoted By: Paul Sellers

Line	Qty	Part Num	Description	Disc	Price	UM	Ext Price	Est Ship
1			OPEN QUOTE					
2	1	FA1815	MOTOR, 15HP,1800RPM,TEFC,GFBZ		$5,038.65	EA	$5,038.65	
			215LPZ,92.4%,PREM EFF,BALDOR					
			DELIVERY 6-8 WEEK ARO - FREIGHT PREPAY AND ADD					
3	1	FA 1815 P	PROPELLER		$1,125.00	EA	$1,125.00	
			DELIVERY 6-8 WEEK ARO - FREIGHT PREPAY AND ADD					
4	1	FA 1815 GB	GUIDE BEARING		$200.00	EA	$200.00	
			DELIVERY 6-8 WEEK ARO - FREIGHT PREPAY AND ADD					

Subtotal:	$6,363.65
Sales Tax:	$0.00
Freight:	Prepaid & Add
Total:	$6,363.65

Thank You For The Opportunity of Quoting!
Energy Management Corporation
SLC, UT•Boise, ID•Denver, CO•Los Angeles, CA

BISCO
The Best Value For Your "Buck"
BONNEVILLE INDUSTRIAL SUPPLY CO.

OREM	801 225-7770
SLC	801 521-2692
FAX	801 224-1456
UTAH	800 892-7534
ST. GEORGE	435 634-0730
ST. GEORGE FAX	435 628-7686

NOT FOR SHIPPING.
MATERIAL MAY NOT BE SHIPPED FROM THIS DOCUMENT.

45 SOUTH 1500 WEST
OREM, UT 84058

1509 SOUTH 270 EAST #7
ST. GEORGE, UT 84790

PICK LIST/QUOTATION FORM

BONNEVILLE INDUSTRIAL SUPPLY CO.

* * Q U O T A T I O N * *

TO: SALEM CITY CORP.
30 W 100 S
SALEM, UT 84653

DATE: 08/15/16 NO. 21299
TO DATE: 08/02/16
JOB:
TERMS: NET 30
FOB: PPD
PREP. BY EVAN JONES

WE ARE PLEASED TO QUOTE YOU ON THE FOLLOWING MATERIAL

PAGE: 1

Qty	Part Number	Description	Price...	Extended
	1 ===>			
1	96165697	BALDOR FA 1815 MOTOR	6251.55	6251.55
1	0019998	FA 1815 P PROPELLER		
1	0019998	FA 1815 GB GUIDE BEARING		
0	0019998	ALL ABOVE ITEMS INCLUDED IN FINAL PRICING		

				6251.55
		QUOTATION TOTALS		6251.55