ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W North Temple, Suite 330
Salt Lake City, Utah 84114

April 30, 2018

VIA ELECTRONIC FILING

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Secretary

RE: **Docket No. 18-035-16 – Rocky Mountain Power's First Annual Sustainable Transportation and Energy Plan Act ("STEP") Program Status Report**
Docket No. 16-035-36 – In the Matter of the Application of Rocky Mountain Power to Implement Programs Authorized by the Sustainable Transportation and Energy Plan Act

In accordance with Docket No. 16-035-36, Rocky Mountain Power (the "Company") hereby submits for filing its First Annual Sustainable Transportation and Energy Plan Act ("STEP") Program Status Report ("STEP Report"). The STEP Report contains the overall calendar year 2017 monthly accounting detail for the STEP program as well as information on the individual STEP programs, using the reporting template that was approved in a letter from the Public Service Commission dated October 12, 2017 ("Reporting Template").

The Reporting Template was designed to inform stakeholders of the STEP program's progress and funding. As requested by the Division of Public Utilities and the Office of Consumer Services in comments regarding the Reporting Template on October 4, 2017 and October 6, 2017, respectively, the STEP Report is a work in progress and may need to be revised annually to keep stakeholders adequately informed on the progress of the STEP programs. The Company welcomes feedback on the STEP Report and looks forward to collaborating with interested parties to ensure the STEP Report is as useful as possible.

The Company respectfully requests that all formal correspondence and requests for additional information regarding this filing be addressed to the following:

By E-mail (preferred): datarequest@pacificorp.com
utahdockets@pacificorp.com
Jana.saba@pacificorp.com
Yvonne.hogle@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

Informal inquiries may be directed to Jana Saba at (801) 220-2823.

Sincerely,

Joelle Steward
Vice President, Regulation

CERTIFICATE OF SERVICE

Docket No. 18-035-16

I hereby certify that on April 30, 2018, a true and correct copy of the foregoing was served by electronic mail to the following:

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Katie Savarin
Coordinator, Regulatory Operations

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

STEP PROGRAM STATUS REPORT

For Period Ended
December 31, 2017

Rocky Mountain Power
STEP and USIP Accounting
CY 2017

Page No.		CY 2017 Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total
	STEP Account Beginning Balance	(15,850,031)	(16,337,861)	(16,526,103)	(16,291,441)	(16,514,676)	(16,109,682)	(16,886,785)	(17,724,486)	(18,481,716)	(19,263,923)	(19,606,986)	(19,654,650)	(15,850,031)
				-	-	-	-	-	-	-	-	-	-	
	Spending by Project:													
2.0	EV Charge Infrastructure	-	-	-	-	-	-	38,699	30,079	121,292	50,465	145,165	101,803	487,502
3.0	Woody-waste Co-Fire Biomass at Hunter Unit 3	-	-	-	-	-	-	-	-	-	-	-	-	-
4.0	NOx Neural Network Implementation	-	0	204,698	-	-	-	-	64,342	-	25,736	89,737	73,254	457,767
5.0	Alternative NOx Reduction	-	-	-	17,500	29,846	19,296	3,500	19,250	10,500	13	22,750	8,750	131,405
6.0	CO2 Enhanced Coal Bed Methane (CO2 Reduction)	-	-	-	-	-	-	-	-	-	-	-	-	-
7.0	Cryogenic Carbon Capture (Emerging CO2 Capture)	-	-	-	-	-	-	35,656	-	-	124,795	-	-	160,451
8.0	CARBONsafe (CO2 Sequestration Site Characterization)	-	-	-	-	-	-	50,000	-	49,000	1,000	50,239	-	150,239
9.0	Solar Thermal Assessment (Grid Performance)	-	-	-	-	-	-	-	-	-	-	-	-	-
10.0	Circuit Performance Meters (Substation Metering)	-	-	-	-	-	-	-	-	-	469	4,369	8,838	13,676
11.0	Commercial Line Extension	-	-	-	-	-	-	-	-	-	-	-	-	-
12.0	Gadsby Emissions Curtailment	-	-	-	-	-	-	-	-	-	-	-	-	-
13.0	Panguitch Solar and Energy Storage Project	-	-	6,549	5,401	3,685	-	16,000	12,458	87,145	130,994	58,496	11,268	331,995
14.0	Microgrid Project	-	-	-	-	-	-	-	-	-	-	-	-	-
15.0	Smart Inverter Project	-	-	-	-	-	-	-	-	-	-	-	-	-
	Utah Solar Incentive Program	181,529	597,920	796,607	518,519	1,121,933	171,544	235,551	335,068	115,951	131,202	119,470	410,118	4,735,412
	Total Spending	181,529	597,921	1,007,853	541,420	1,155,464	190,840	379,405	461,197	383,888	464,674	490,226	614,031	6,468,448
	Surcharge Collections	(609,908)	(724,358)	(715,692)	(705,551)	(692,579)	(907,394)	(1,156,962)	(1,155,614)	(1,100,170)	(740,791)	(469,605)	(778,359)	(9,756,984)
	Ending Monthly Balance before Carrying Charge	(16,278,411)	(16,464,299)	(16,233,942)	(16,455,572)	(16,051,791)	(16,826,236)	(17,664,341)	(18,418,904)	(19,197,999)	(19,540,040)	(19,586,365)	(19,818,978)	(19,138,568)
	Carrying Charge	(59,450)	(61,804)	(57,499)	(59,104)	(57,891)	(60,549)	(60,145)	(62,813)	(65,924)	(66,947)	(68,285)	(68,860)	(749,270)
	Ending Monthly Balance	(16,337,861)	(16,526,103)	(16,291,441)	(16,514,676)	(16,109,682)	(16,886,785)	(17,724,486)	(18,481,716)	(19,263,923)	(19,606,986)	(19,654,650)	(19,887,838)	(19,887,838)

STEP Project Report

Period Ending December 31, 2017[1]

STEP Project Name:

Electric Vehicle Charging Infrastructure:

1. Electric Vehicle Time of Use Pilot – Schedule 2E;
2. Plug-in Electric Vehicle Pilot Incentive Program – Schedule 120; and
3. Plug-in Electric Vehicle Load Research Study Program – Schedule 121

Project Objectives:

- Offer a time of use rate schedule option for residential customers who own a plug-in electric vehicle;
- Promote plug-in electric vehicle charging infrastructure and time of use rates; and
- To study the load profiles of customers who have plug-in electric vehicles

Table 1 – Program Accounting

	2017 Calendar Year Expenditures	2017 Budget Costs/Commitments
Time of Use Pilot	$6,800	$2,800*
Non-Residential AC Level 2 Chargers	$116,157	$65,309*
Non-Residential & Multi-Family DC Fast Chargers	$54,618	$54,618*
Non-Residential & Multi-Family Grant-Based Custom Projects and Partnerships	$0	$1,359,874**
Administrative Costs	$176,176	$176,176
Outreach & Awareness Expenditures	$133,751	$133,751
Total	**$487,502**	**$1,792,528**
OMAG Expenses[2]	$32,684	$0

***** Includes incentive payments for activity through September 30, 2017. Remaining budgets for these measures were re-allocated to custom projects for the remainder of 2017.

** Committed funds from 2017 budget for custom projects. See details in Table 3.

[1] Incentive payments for the Time of Use Pilot, Non-Residential AC Level 2 Chargers, and Non-Residential & Multi-Family DC Fast Chargers from October 1, 2017 through December 31, 2017 used 2018 incentive funds, consistent with the program structure approved in Docket No. 16-035-36, and will accordingly be included in the reporting period for the 2018 budget.

[2] Program expenditures prior to Commission approval in July 2017.

Table 2 – Charger Ports by Category/Technology, & TOU Customers[3]

City (UT)	Category	AC Level 2 Charger Ports	DC Fast Charger Ports	Time of Use Customers
Salt Lake City	Workplace/Public	60	2	3
	Multi-Family	4	-	
Sandy	Workplace/Public	1	-	-
	Multi-Family	-	-	
Millville	-	-	-	1
Tooele	-	-	-	1
Brigham City	-	-	-	1
Draper	-	-	-	1
Layton	-	-	-	2
Magna	-	-	-	1
Ogden	-	-	-	2
Park City	-	-	-	2
Total	**-**	**65**	**2**	**14**

Table 3 – Custom Projects[4]

Custom Projects	Incentive	Description	Equipment Type
Project 1	$250,000	Installation of an electric bus charger for an electric bus that will provide free public transit throughout a community. The electric bus will reduce traffic congestion and improve carbon emissions.	500 kW Electric Bus Charger
Project 2	$8,000	Project 2 covers three aspects of installation and monitoring that include: 1) fees for materials associated with installing charging units in snowy, high-alpine environments; 2) two meters to track monthly usage of Tesla and standard chargers (as this would otherwise not be available,); and 3) develop a comprehensive marketing plan to promote electric vehicle chargers and promote electric vehicles at a resort.	4 AC Level 2 Chargers (single port)
Project 3	$470,000	The goal of this project is to provide EV charging along major traffic corridors in Utah. DC Fast chargers will be strategically placed along interstate corridor to reduce range anxiety among EV drivers.	6 AC Level 2 Chargers & 6 DC Fast Chargers (single ports)

[3] Only includes equipment and Time of Use customers that received incentives using 2017 funds for activity through September 30, 2017. Does not include equipment from custom projects.
[4] Custom projects listed in Table 3 may evolve and are expected be completed throughout 2018. Actual incentive amounts and installed equipment will be included in the next reporting period for completed custom projects.

<table>
<tr><th>Custom Projects</th><th>Incentive</th><th>Description</th><th>Equipment Type</th></tr>
<tr><td>Project 4</td><td>$153,000</td><td>This project aims to provide electric vehicle charging for the public and employees at a prominent location in downtown Salt Lake City by installing 12 AC Level 2 dual port charging stations, and infrastructure for seven future stations.</td><td>12 AC Level 2 Chargers (dual ports)</td></tr>
<tr><td>Project 5</td><td>$237,500</td><td>The goal of this project is to significantly expand and enhance the EV charging infrastructure at a major workplace in the Salt Lake Valley.

South Parking Lot:
Five dual-port Level 2 EV chargers which will be pay-for-use and available to the public.
Three dual-port Level 2 EV chargers for fleet and enterprise vehicles.
One Level 3 pay-for-use EV charger in the east-side visitor parking area. If unable to support a Level 3 charger, the plan would be to install an additional dual-port Level 2 EV charger at this location.
North Parking Lot:
Two dual-port Level 2 pay-for-use EV chargers which will be available to the public.
Tech Center: We are proposing to have two dual-port Level 2 chargers for state vehicles. We are also proposing to add two pay-for-use dual-port Level 2 chargers that would be in front of the Tech Center and be available for public use.
Multiple EV chargers throughout the campus facilities</td><td>18 AC Level 2 Chargers & 1 DC Fast Charger (dual ports)</td></tr>
<tr><td>Project 6</td><td>$50,000</td><td>A city plans to collaborate with commercial and industrial businesses to increase the adoption of electric vehicle purchases within the city and county in order to satisfy growing driver demand; increase property value, complement LEED and Green Building Programs, and achieve the city community fuel, carbon and energy goals. The project strives to use innovations, test new ideas, and pursue interesting opportunities to better understand how consumers think about and use PEVs to further increase the</td><td>2 AC Level 2 Chargers and 1 DC Fast Charger (single port)</td></tr>
</table>

Custom Projects	Incentive	Description	Equipment Type
		market penetration of PEVs and hybrids. Installed on city property for public use.	
Project 7	$57,005	The site selected for the EVSE installation is an Electric Vehicle & Roadway (EVR) Research Facility and electrified test track. The EVR is a state-of-the-art research facility at the forefront of electric vehicle charging and roadway technology development. The EVR is the most appropriate location in Rocky Mountain Power's service area to conduct high-level EV research, enhance infrastructure, and promote sustainable transportation. This project proposes to install two AC Level II chargers and one DC Fast Charger. All ports will be equipped with an advanced network and innovative data tracking capabilities. The DC Fast Charger as proposed herein will be the first available to all EV drivers in Northern Utah. The customizable data will provide further research, grants, and contracts as well as fortify existing research to help develop industry partnerships.	2 AC Level 2 Chargers and 1 DC Fast Charger (dual ports)
Project 8	$69,369	This site plans on installing four new Level 2 charging stations and one DC fast charger to increase the amount of chargers available to the public, and staff. This site currently has two Level 2 dual port charging stations. One located at the main entrance to campus for the public, free of charge in the Visitor Lot. The other charging station is located by the Facilities building for fleet vehicles. Three new level 2 charging stations will be located around the entire main grounds with one located at the West grounds. The DC Fast Charger will be located in the visitor lot in the front of campus. This is to serve the growing public facility and will be positioned with good access to I-15.	4 AC Level 2 Chargers and 1 DC Fast Charger (dual ports)
Project 9	$65,000	This site intends to install EVSE in the parking lot next to an LEED Platinum certified Building. This project involves installing one DC Fast Charger under the solar canopy in the parking lot, and one dual port AC Level 2 charger.	1 AC Level 2 Charger and 1 DC Fast Charger (dual ports)

Time of Use and Load Research Study

Fourteen customers received incentives with 2017 funds for participating in the Time of Use program, apart from the load research study. The Company's website[5] describes the time of use rates and the associated $200 incentive. Time of use rates were not actively promoted in 2017 however, as the Company is waiting to do so until recruitment efforts for the load research study subside in an effort to avoid confusion in the marketplace. Recruitment efforts for participants in the load research study did not commence until 2018 due to the vendor contract not being finalized.

2017 EV Program Key Findings:

Technology

Electric vehicle owners in Utah represent a small percentage of total vehicles (1-2% adoption). Electric vehicles are still considered new and emerging technology, which creates hesitancy in changing driver behavior.

Education

Education on Electric Vehicle Supply Equipment (EVSE) is important. As with any new and emerging technology, the market was not only unaware of what EVSE is but had misconceptions, mainly surrounding price and ease of operation, which Rocky Mountain Power diligently worked on to make sure all interested parties had correct and accurate information. However, despite not knowing how EVSE worked, the general public at large was very excited about the prospect of electrification and the benefits it provides.

Installation Costs

Installation costs for electric vehicle chargers can be barriers for non-residential customers. Installation rates vary greatly depending on the proximity of the site to the panel, whether trenching needs to be done, and other factors. Installation cost was enough of a barrier to frequently prevent projects altogether.

Incentive Options

Program incentives are providing increased opportunities to install electric vehicle chargers for multi-family, workplace, public locations and interstate travel throughout Utah. Attractive incentives are allowing non-residential locations the ability to install electric vehicle chargers where it was previously uneconomical to install.

Program Partnerships:

WestSmartEV – Live Electric

[5] https://www.rockymountainpower.net/env/ev/utah-ev-time-of-use-rate.html

In addition to the STEP Electric Vehicle Program, Rocky Mountain Power received a grant from the Department of Energy (DOE) to accelerate adoption of plug-in electric vehicles (PEV) in communities located within the Company's electric service territory across the intermountain west by developing a large-scale sustainable PEV charging infrastructure network with coupled PEV adoption programs. The project tasks include: (1) developing electric highway corridors along I-15, I-80, I-70, and I-84 (2) advancing Workplace Charging within the corridors, (3) incentivizing conversion of fleet vehicles to PEVs within the corridors, (4) building community partnerships and incorporating Smart Mobility programs to ensure all efforts within the corridors are aligned with long term transportation planning, (5) collecting, processing, and applying data from across all activities to inform project reporting, develop new tools for utility integration of charging infrastructure, and detail lessons learned and best practices, and (6) coordinating outreach, education and dissemination of best practices through a series of workshops and one-on-one meetings with business leaders though community partners

STEP Project Report

Period Ending: December 31, 2017

STEP Project Name: Woody-waste Co-Fire Biomass at Hunter Unit 3

Project Objective:

This proposed project consists of two 18-hour co-firing tests of processed woody waste (biomass) to be fired in the Hunter Unit 3 boiler. The target heat input from woody waste material is 10% of the required total fuel input of the Unit 3 boiler. The processed woody waste will come from Utah forests and will consist wood resources including scrap and waste material from logging operations. Two types of processed woody waste will be tested. The primary objective of these tests will be to determine whether these processed biomass fuels can effectively be used as "drop-in" replacements in lieu of burning coal. In addition to displacing coal and its attendant CO_2 and NOx emissions, using these processed woody waste materials will have the benefit of minimizing particulate matter emissions associated with either controlled or uncontrolled burns of collected forest materials. Performing these tests will also be used as a mechanism to further evaluate and demonstrate these Utah-based technologies.

Project Accounting:

Cost Object	2017
Annual Collection (Budget)	$0.00
Annual Spend (Capital)	$0.00
Committed Funds	$0.00
Uncommitted Funds	$0.00
External OMAG Expenses	$0.00
Subtotal*	$0.00

*the majority of project spending is expected to occur during CY 2018.

Project Milestones:

Project Milestones	Delivery Date	Status/Progress
Contracts with PacifiCorp complete	UofU – June 27, 2017 Amaron – Winter 2018 AEG – Winter 2018	Complete On Target On Target
Select biomass fuel source	December 1, 2017	Complete

Process first ton of biomass material	Amaron – March 2018 AEG – May 2018	Amaron – Complete AEG – On Target
All biomass material delivered to the Hunter plant	By August 31, 2018	On Target
Finalize test burn plan and operating procedures	August 1, 2018	On Target
Test burn monitoring equipment installation complete	September 25, 2018	On Target
Test burn conducted	September 30, 2018	On Target
Final report completed	March 31, 2019	On Target

Key Challenges, Findings, Results and Lessons Learned:

Challenges	Anticipated Outcome	Findings	Results	Lessons Learned
Secure raw biomass material	Several biomass sources were researched and priced	Finding biomass sources that could guarantee sufficient material availability at a specific price was a challenge	Both Amaron and AEG will both use Woodscapes as their biomass supplier	
Design the test burn and monitoring plan	University of Utah is developing the project plan			
Address any plant operation or air permit concerns	Work with Jim Doak to notify the State of Utah about the project			

Program Benefits:

The project objective is to create an option to use forest waste products to generate electricity without requiring construction of new facilities or expensive equipment retrofits at existing coal plants. The limited amount of biomass material that exists in Utah and the mountain west region is a supply chain problem that makes it very difficult to justify the capital costs required to retrofit an existing plant or build a new biomass specific generation facility. The ability of an existing coal plant to supplement its coal fuel with biomass, when and only when biomass is available, eliminates the supply chain problem of needing to have continuous resources available to fuel a biomass specific generation resource.

Burning processed biomass in a coal plant with a controlled burn environment and emissions control equipment should provide air quality benefits compared to the air emissions of forest fires or the intentional burning of slash piles in an open air environment.

Potential future applications for similar projects:

The ability to burn biomass in existing coal plants would create a new option for disposing of wood waste from forest thinning activities. Wood waste products that currently have little or no commercial value could be burned in a controlled environment, rather than an open air environment, and would provide the benefit of generating electricity.

STEP Project Report

Period Ending: December 31, 2017

STEP Program Name: Huntington Plant Neural Network Optimization Project

Program Objective:

The objective of PacifiCorp's study and use of Neural Network Optimization/Optimizers (NNO) for control optimization is to achieve the best possible unit efficiency with the lowest possible emissions while safely operating our Electrical Generations Units (EGU). The goal of control optimization is unit specific; however, optimization efforts should always address the following: safety, environmental constraints, equipment condition and plant or fleet operating requirements. There are three factors affected by control optimization that must always govern optimization efforts within the PacifiCorp fleet. In order of priority they are:

> Safety – Optimization efforts will not jeopardize personnel safety.
>
> Environment - Emissions limits will take precedence over all optimization aspects except safety.
>
> Availability – Emphasis on maintaining unit reliability will take precedence over optimizing the unit for efficiency.

This project will provide a detailed analysis of the implementation of NNO on unit controls. The NNO control optimization will initially be applied to the combustion control system. During this time the available control inputs and outputs will be evaluated relative to their use or weight by the NNO. With the combustion optimization targeting Nitrogen Oxides (NO_X) for improved emissions and Carbon Monoxide (CO) for improved emissions and unit efficiency. Once the combustion control phase is well underway additional plant systems will be evaluated for control optimization. It is expected that the Flue Gas Desulfurization FGD control systems will be next for control optimization. The experience gained from combustion control optimization will guide those decisions.

Project Accounting:

Cost Object	2017
Annual Collection (Budget)	$547,807
Annual Spend (Capital)	$427,767
Committed Funds	$0.00
Uncommitted Funds	$0.00

External OMAG Expenses	$30,000
Subtotal	$457,767

Project Milestones:

Project Milestones	Target Date	Status/Progress
Project Kick off Meeting	January 26, 2017	Complete
Contracts with PacifiCorp complete	February 15, 2017	Univ. of Utah – Complete Griffin Software – Complete
Instruments upgrades complete	June 5, 2017	Complete
Base Line Data set established. 3 Month Average	April 1 – June 30, 2017	For the 425 – 450 MW range NO_x = 0.23 lbs/mmbtu CO = 348 ppm
Unit base line optimization Manual Boiler tuning	July 27 – August 5, 2017	Complete
Initial installation complete	August 11, 2017	Complete
Neural Network Model and Predictors running	November, 30 2017	Complete
Optimizer turned on	March 31, 2018	On Target
Parametric study on optimization of auxiliary systems complete	August 31, 2018	On Target
Annual progress report complete for Year 2	March 31, 2019	On Target
Flue Gas Desulfurization FGD control systems	June 30, 2019	On Target
Exploratory study on dynamic optimization with set point ramping complete	August 31, 2019	On Target
Final study on impact on emissions complete	December 31, 2019	On Target

Key Challenges, Finding, Results and Lessons Learned:

Challenges	Results/Progress
a. Communications between the Neural Network Server and the Distributed Control System (DCS)	Problems with OPC have been identified and resolved. Changed communication protocol to Modbus to prevent further issues in the future.

b. Supplied Basic Optimization component of software incomplete	Building new optimization algorithm as interim solution. Griffin optimizer is been refined.
c. Reducing NO_x (Nitrogen Oxides)	Initial model tuning and using predictor at near full load operations is showing positive reduction of NO_x. As seen in below of about 6%.
d. Reducing CO (Carbon Dioxide) and unburned coal improvement.	The initial indication for CO reduction is very positive. Initially seen a large improvement with as much a 50% reduction in CO.
e. Reheat tube temperatures high during load ramping up events forces less than optimal configuration to be used.	Several solutions to this problem have been tried. A solution that allows optimization and controls temperature has not been found yet.
f. Low load NOx reduction very difficult due to minimum air flow requirement.	Air flow monitoring devices have been installed and are currently being added to control system. Should allow reduction of air flow, and improved NOx reduction at low load.
g. Flue Gas Desulfurization FGD control systems	Not started at this time.

Program Progress and Benefits:

With the Griffin system installed the operational and baseline data was collected. With the support from the University of Utah, the data was collected, reviewed, and parsed appropriately to have the best data possible for the models. The Neural Network models were built and inputs configured for the predictor to achieve the best output for matching real conditions. Challenges encountered included wind box pressure excursions and high reheat tube metal temperatures. The solution to high tube temperatures involves a combination of soot blowing, increased O_2, and manipulation of SOFA tilts. The effort to control tube temperatures counters what is needed to control NO_X. Griffin uses a particle swarm optimizer to determine if one damper position is better than another. This works by using the neural model to predict NO_X at the current damper positions. The optimizer then selects values for several other dampers and performs what-if scenarios. The neural model then predicts the NO_X at each damper position. Each position is then adjusted to a new position closer to the position with the lowest NO_X. This process is repeated several thousand times, until one is selected as the lowest NO_X. Then this process continues.

The initial phases have shown reduction benefits in both NO_X and CO, compared to the three month baseline data as shown below. Since NO_X and CO vary by load, only loads during the given time period as can be seen in Chart 1 should be compared. The consistent load range of 425-450 mw was chosen - 90 – 95% of full load. Since this three-month baseline date was in the spring loads were typically lower.

NO_X CO

May to Jun '17	**0.230**	**348**	**Baseline**
Dec-17	**0.216**	**147**	
% Reduction	6.1%	57.8%	

The data/charts for these can be seen in charts 1 – 4.

With these results, the next steps appear promising. With the continued support from the University of Utah and Griffin, the optimizer is being configured and will continue running in 2018.

Results/Appendix

Chart 1 – NO_X and CO versus load and percent of time at Load. (baseline)

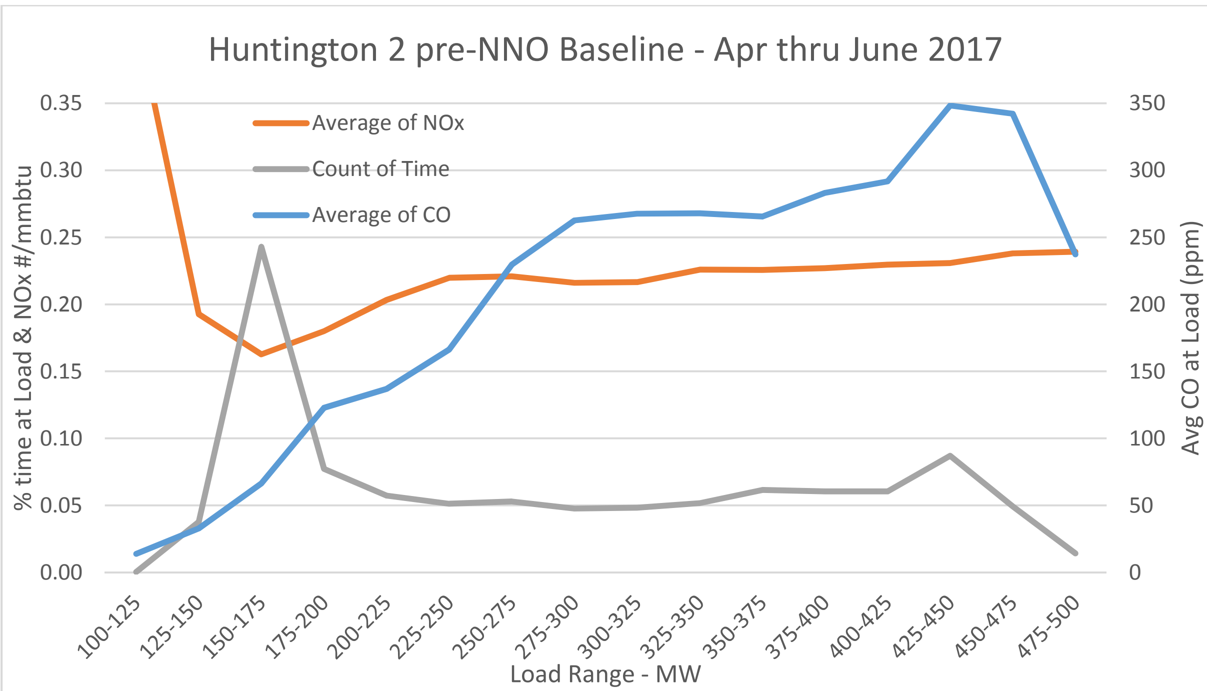


Chart 2 - Three Month data establishing baseline.

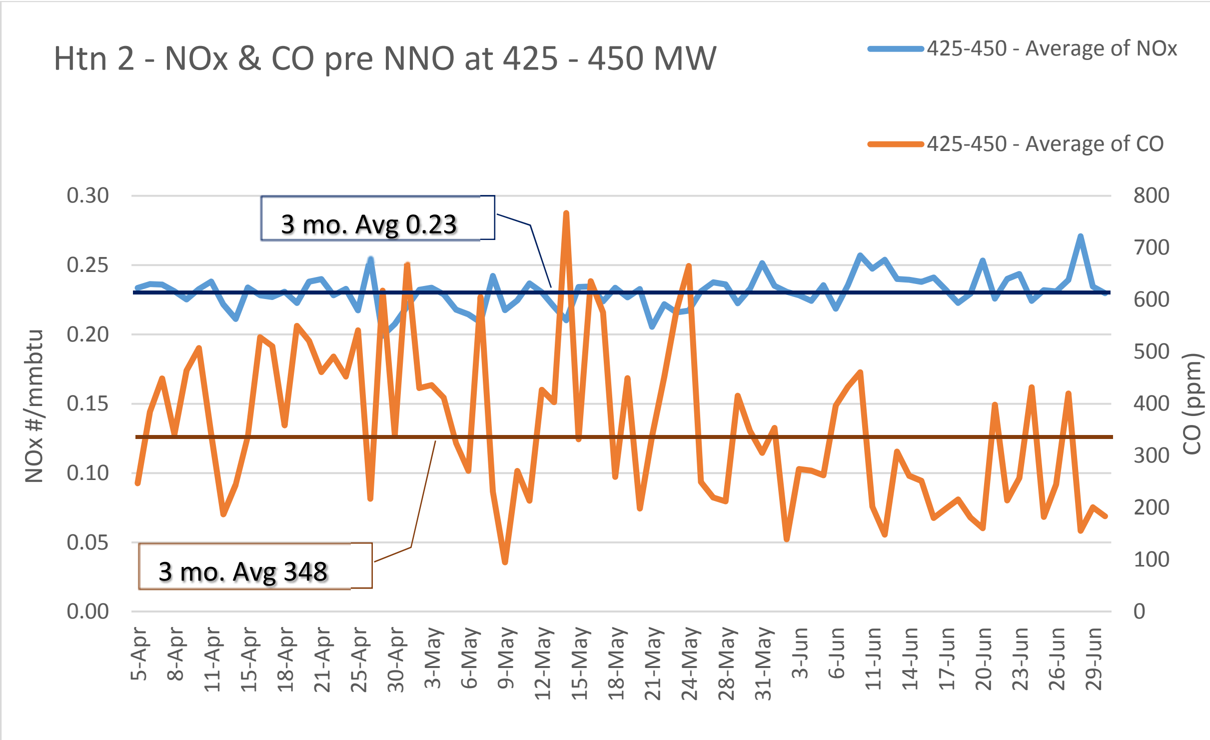


Chart 3 – NOx and CO versus load and percent of time at Load. December 2017

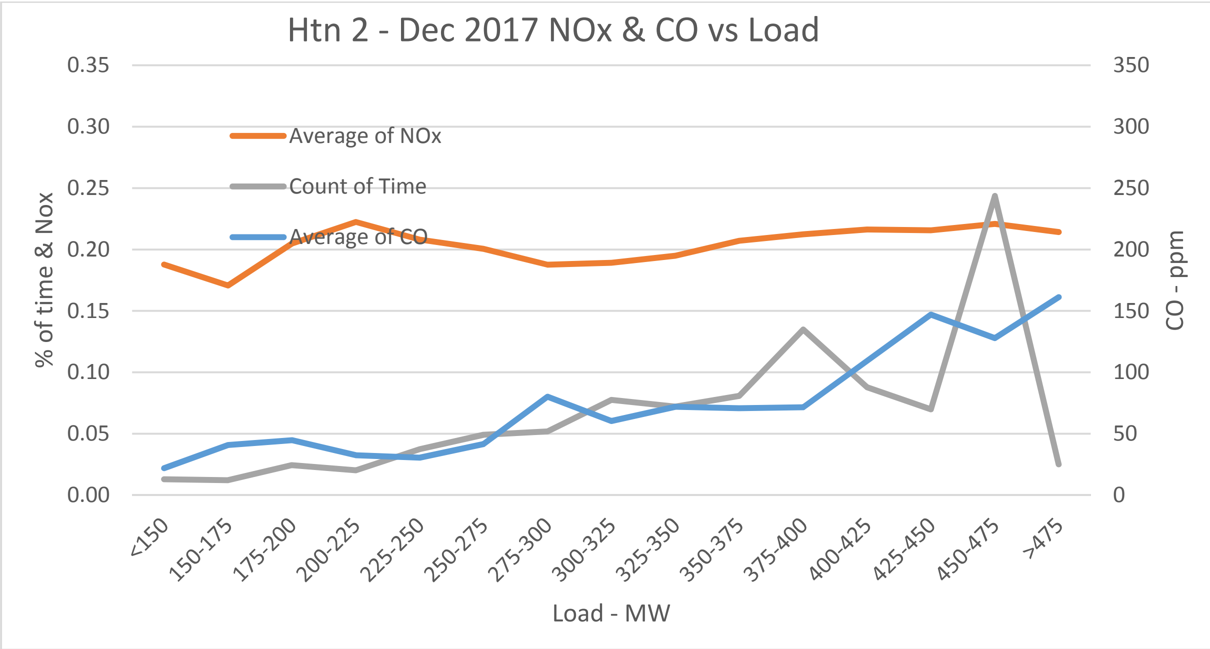
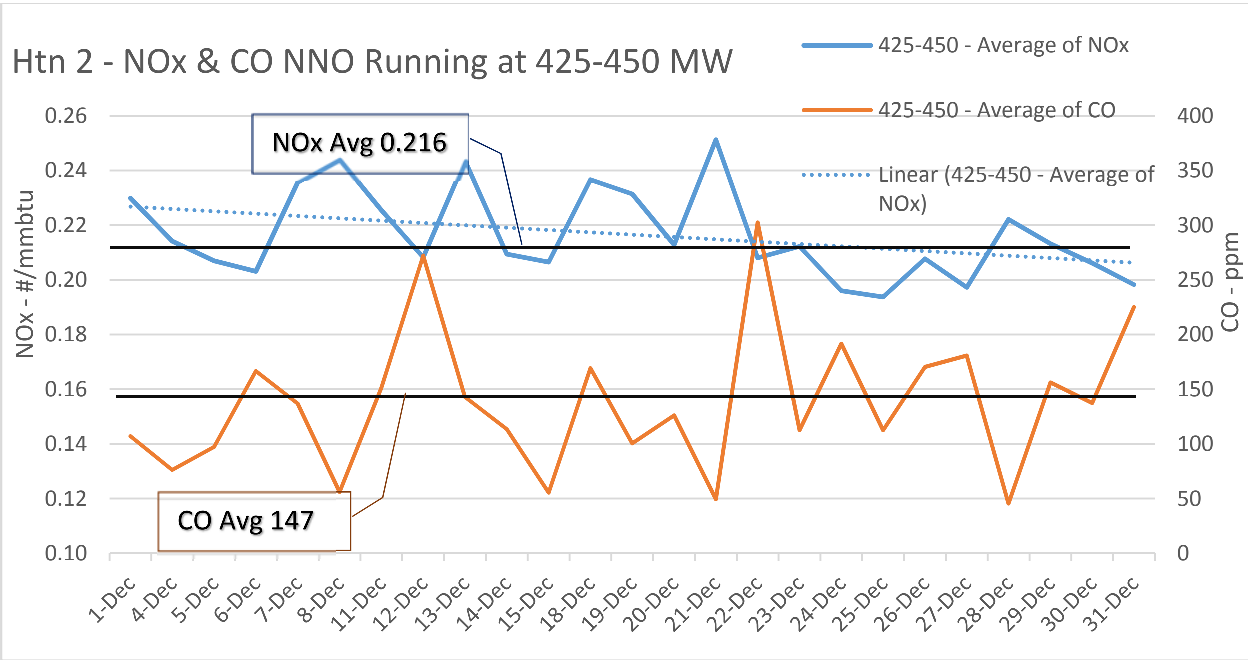


Chart 4 – December 2017 – NNO running - NO_x trending down



Potential future applications for similar projects:

With the early positive results, the Huntington plant is evaluating a similar Neural Network Optimization on Unit 1.

STEP Project Report

Period Ending: December 31, 2017

STEP Project Name: Utah STEP Initiative Alternative NO_X Reduction

Project Objective:

The project is to perform one or more utility scale demonstration tests of an alternative NO_X emission control technology at the Hunter or Huntington power plants. The objective of the project is to find a cost effective technology, or combination of technologies, that can achieve or approach the NO_X emissions that match a Selective Catalytic Reduction (SCR).

Project Accounting:

Cost Object	2017
Annual Collection (Budget)	$125,000
Annual Spend (Capital)	$0.00
Committed Funds	$0.00
Uncommitted Funds	$0.00
External OMAG Expenses	$131,405
Subtotal	$131,405

Project Milestones:

Project Milestone	Delivery Date	Status
Kick off meeting	March 30, 2017	Complete
Draft version of RFI for Alternative NO_X Technologies	May 18, 2017	Complete, draft received on May 1, 2017
Issue RFI for Alternative NO_X Technologies	May 29, 2017	Completed
RFI Response Due	June 22, 2017	Completed
Summary of RFI Response	August 6, 2017	Completed
Issue RFP for Alternative NO_X Technologies Demonstration Test	August 20, 2017	Complete, August 24, 2017
RFP Response Due	October 9, 2017	Completed

Selection of Technologies for Demonstration Test	December 27, 2017	Complete
Submit Implementation APR for Demonstration Test	February 20, 2018	Deferred (see key challenges)

Key Challenges, Findings, Results and Lessons Learned:

Description of Investment	Anticipated Outcome	Challenges	Findings	Results	Lessons Learned
a. Request for Information	Selected vendors for alternative emission reduction technology	Limited availability implementable technology	Sixteen vendors were approached for their technology	Two vendors provided a substantially different technology for implementation	There is limited number of technologies on the market reach SCR type emission reduction
b. Request for Proposal Cost	A technology supplier capable for performing a demonstration test within the allocated budget	Limited number low cost technology for emission reduction	Only two vendors could meet the target emission reduction rate and neither were within the target budget	No vendor could be sourced that could meet the STEP requirement and were within the allocated budget.	The company should provide more direction to potential vendors before release of the RFP to gain a better understanding as to the cost associated with a demonstration test.

Program Benefits:

The benefit to the Company, and ultimately to the Customer, is to find a technology, or combination of technologies, that achieve NOx emission rate that approach or meet those that can be achieved by an SCR. Such a technology would be beneficial to rate payers and the Company by meeting the emission targets for the facility at lower cost. The demonstration test would allow the Company to evaluate potential technologies that meet these goals.

Project Challenge and Recommendations:

Rocky Mountain Power has completed a competitive request for proposals ("RFP") from four NOX control technology vendors. The four vendors were evaluated and none were capable of meeting the project's objectives within budget. As described in detail in the STEP NOx RFP Recommendation Memo attached, the Company recommends abanding the alternative NOX emission control technology demonstration test and utilizing the remaining STEP funds to expand other STEP projects. The Company is developing a proposal for the STEP funds which will be filed during CY 2018 with the Commission for approval.

Attachments:

1. Owner's engineer proposal recommendation report
2. Utah STEP Alternative NOx Technology Demonstration Test Memorandum

Introduction

This memo documents the results of S&L's preliminary review and technical evaluation of the RFP responses received as part of the Utah STEP Initiative Alternative NO_X Reduction Project. The goal of the project is to identify an alternate NO_X control solution (consisting of one or more NO_X control technologies) in order to achieve the mandated lower NO_X emissions at Hunter and Huntington, equivalent to SCR technology (~ 0.07 lb/MMBtu).

PacifiCorp received four responses to their Request for Proposal (RFP) for an Alternative NO_X Control Technology Demonstration. The four respondents included the following companies and proposed technology solutions:

VENDOR	TECHNOLOGY FOR DEMO	ESTIMATED TARGET EMISSION RATE FOR DEMO
AECOM	Ozone Injection	Approx. 0.05 lb/MMBtu
Air Pollution Control Solutions (APCS)	PerNOxide Injection	0.093-0.132 lb/MMBtu
Fuel Tech	SNCR	Approx. 0.165 lb/MMBtu (25% Reduction based on 0.22 lb/MMBtu baseline)
GE Power	Umbrella SNCR	Approx. 0.155 lb/MMBtu (30% Reduction based on 0.22 lb/MMBtu baseline)

A round of questions was issued to each respondent (except FuelTech) in October, 2017. Responses were received by November 9, 2017.

Preliminary Technical Evaluation

The proposals were evaluated according to the technical assessment criteria previously established by PacifiCorp and S&L. The following table shows the Technical Assessment Criteria and Scoring Methodology.

Item	Technical Assessment Criteria	Scoring Methodology
1	Testability – Is the proposed technology testable at Huntington?	Go / No Go
2	Is stack testing included in the proposal?	Go / No Go (No Go does not mean exclusion)
3	Does the proposed technology satisfy the STEP Initiative criteria for demonstration?	Go / No Go
4A	Demonstration Test Expected NO_X Reduction related to Permit Limit (30-day rolling average)	Scale: 1 point per 0.01 lb/MMBTU NO_X below current operation (0.22 lb/MMBtu, 2016 average)

4B	Plant Modifications Required	Permanent modification that affect plant operation and major changes required to plant power and/or water system 0-2, Permanent modification or major changes to plant power and/or water systems that do not affect plant operation 3-5, Temporary and removable modifications 6-8, No modifications 9-10.
4C	Technology Implementation History – Has the technology been implemented before on other coal fired boilers?	Technology has never been implemented or used 0-2, Technology only been utilized in bench testing 3-4; Technology has been utilized in slip stream pilot testing 5-6; Technology has been utilized on a full-scale boiler 7-8; Technology has been permanently installed/utilized on at least one coal fired utility boiler 9-10. NOTE: reduction of 2 point for known technologies that are not innovative to the coal fired utility boiler.
4D	Detail Work and Test Plan – Has the respondent provided sufficient information to demonstrate their understanding of the scope of the RFP and provided information so the company can make an informed decision regarding test modifications and equipment? Has the respondent met the criteria of the RFP?	Demonstrates marginal understanding and information 1-3; Demonstrates adequate understanding and information 4-6; Demonstrates not only understanding of requirements but shows additional though, creativity and understanding of risks and issues 7-10.
4E	Auxiliary Power and Utility Needs – Do the utilities required for the demonstration test pose a risk to operation of the unit? Be it auxiliary power consumption, demineralized water, steam or other? NOTE: this excludes reagent costs as these are to be provided by Contractor.	Rank based on cost of utilities to plant for demonstration. Highest costs for supply power, water, etc. 0-3; Additional costs for other utilities 4-7; Lowest cost (i.e. bringing a generator) 8-10.
4F	Schedule – Has the respondent submitted a schedule that the company can utilize for scheduling of demonstration testing? How does the proposed schedule impact the project and or plant?	No schedule provided 0; provided high level schedule with limited duration information and/or doesn't meet schedule as requested 0-3; provided schedule with enough information to plan demonstration test and/or moderate construction schedule 3-7; provided schedule detailed enough for company planning of demonstration test with minimum set-up required 8-10
4G	Other Emission Sources Created from Test – Will the reagent used in the test cause other regulated emissions to be generated.	New source pollutants created 1-3; additional non-regulated emissions created 4-7; No new emissions created 8-10
4H	Cost of Demonstration Testing – Pricing varies significantly based on estimated time on-site for contractor's personnel, cost of demonstration equipment, whether or not demonstration testing requires a testing contractor to be hired, etc.	Rank based on price. Highest cost 1-3; Moderately priced 4-7; Lowest cost 8-10 ***EXCLUDED FROM THE PRELIMINARY TECHNICAL EVALUATION***

4I	Cost-Sharing and/or Co-Funding Opportunities	No cost-sharing/co-funding 0; provided small cost-sharing amount with limitations (such as schedule, contract negotiations, etc.) 1-3; provided cost-sharing amount without limitations 4-7; provided largest amount of cost-sharing without limitations 8-10

For each of the above criteria, S&L has evaluated the proposals on a preliminary basis and has established the following preliminary scoring for each category and bidder.

Go / No Go Criteria

Testability

All of the technologies can be tested on Unit 2 at Huntington Station, therefore all four bidders can move forward according to this criteria.

Stack Testing

All of the bidders included stack testing in their proposal with the exception of FuelTech who proposed to use the existing CEMS to measure NO_X during the demonstration. As not meeting this criteria does not exclude a bidder from moving forward, all four bidders can move forward according to this criteria.

STEP Initiative Criteria

The Utah Sustainable Transportation and Energy Plan is a policy that allows which directs funding for the exploration of new technologies and innovative programs to accomplish the goal of providing clean energy options and clean air. The Plan is intended, among other things, to research clean coal technologies and other emerging technologies.

The technologies proposed by AECOM (ozone injection) and APCS (PerNOxide injection) are both emerging technologies which have not been implemented at a full scale in the utility industry. Therefore, both of these technologies meet the STEP initiative criteria and can move forward according to this criteria.

SNCR technology proposed by FuelTech and GE has been widely implemented throughout the utility industry and is not considered to be an innovative or emerging technology. However, the proposed technology by GE is an innovative approach to traditional SNCR technology which has not been installed at a full scale basis in the United States. Therefore, according to this criteria, we believe that GE's proposed technology can move forward while FuelTech's technology does not meet the criteria and therefore should not be evaluated further.

Technical Criteria

<u>NO_X Emissions</u>

Of the proposed technologies, only the ozone injection (proposed by AECOM) is predicted to achieve NO_X emissions below the required future permit limit with SCR (0.07 lb/MMBtu at time of RFP issue).

The APCS proposed demonstration is expected to achieve an emission rate in the range of 0.093-0.132 lb/MMBtu while the GE proposed demonstration is expected to achieve approximately 0.14 lb/MMBtu (based on a 30% reduction from a 0.20 lb/MMBtu baseline). The GE control efficiency was evaluated based on the 2016 average baseline of 0.22 lb/MMBtu for the scoring methodology.

According to the scoring methodology, AECOM was awarded the most points for this criteria, followed by APCS and GE.

AECOM

0.22 lb/MMBtu – 0.05 lb/MMBtu = 0.17 lb/MMBtu x 1 Point/0.01 lb/MMBtu = <u>17 Points</u>
Adjusted to a **10** for the 10 point scale.

APCS

0.22 lb/MMBtu – 0.09 lb/MMBtu = 0.13 lb/MMBtu x 1 Point/0.01 lb/MMBtu = <u>13 Points</u>
[multiply by 10/17 to account for AECOM max score]
Adjusted to a **7.5** for the 10 point scale.

GE

0.22 lb/MMBtu – 0.155 lb/MMBtu = 0.065 lb/MMBtu x 1 Point/0.01 lb/MMBtu = <u>6.5 Points</u>
[multiply by 10/17 to account for AECOM max score]
Adjusted to a **4** for the 10 point scale.

The following table summarizes S&L's scores for this criteria based on the preliminary technical evaluation:

Item	Technical Criteria	AECOM	APCS	GE
4A	NO_X Emissions	10	7.5	4

<u>Plant Modification</u>

AECOM's proposed technology requires significant permanent modification to the existing facility including installation of a liner and baffles in the inlet ductwork to the FGD absorber vessel to be tested. In response to questions, AECOM indicated that removal of the baffles would be left to PacifiCorp, but estimated the baffles would result in approximately 0.25-0.75 in.w.c. If PacifiCorp elects to remove the baffles an additional unit outage would be required. If remaining, the baffles would result in an increase in pressure drop in the duct which could impact the balance of flue gas to each absorber vessel.

APCS indicated that they intend to re-use existing boiler doors and sootblower openings as available for the demonstration, but indicated that the final location of the required openings (up to 10 required openings) for the demonstration will not be determined until CFD modeling is completed after award. While the use of existing sootblower ports would have an impact on boiler cleaning during the test, this is not expected to have any significant long-lasting impacts. This evaluation is based on assuming that APCS will primarily use existing ports or boiler openings for their demonstration. If new ports are required for the demonstration, while permanent, these would have minimal impact on the operation of the unit. However, if required their score would likely be adjusted.

GE requires new ports to be installed for the demonstration. As discussed above, new ports would be permanent but would likely have a minimal impact on the operation of the unit (primarily impacting heat transfer surface area to a small degree) long term.

The following table summarizes S&L's scores for this criteria based on the preliminary technical evaluation:

Item	Technical Criteria	AECOM	APCS	GE
4B	Plant Modification	2	6	4

Technology Implementation History

AECOM has performed some small slip stream testing previously, but has not demonstrated their ozone injection technology at full scale.

Based on their preliminary responses to the previous Request for Information, it is understood that APCS has performed bench scale testing but has not demonstrated their PerNOxide technology on a pilot scale or beyond. APCS was asked to provide previous installation and testing experience, but did not provide any additional information regarding installation and testing of the proposed technology.

GE has installed their Umbrella SNCR technology at a full scale on coal-fired boilers outside of the United States; however, they have yet to demonstrate their technology at a full scale on a coal-fired utility boiler domestically.

The following table summarizes S&L's scores for this criteria based on the preliminary technical evaluation:

Item	Technical Criteria	AECOM	APCS	GE
4C	Technology Development	5	4	9

Detail Work and Test Plan

AECOM provided a very detailed test plan, which clearly identified their scope, approach to testing, requirements of PacifiCorp. There is a significant amount of work in PacifiCorp's scope as defined by AECOM to support the installation and demonstration.

APCS's initial proposal was lacking detail with significant information identified as "TBD". Questions were posed to APCS regarding their proposed test plan and schedule and their response provided a narrative of a five phase approach to the test which met the intent of the Specification. As part of this discussion, APCS identified the variables which would be adjusted during the preliminary parametric testing and how this would be applied to the long term testing. In addition, the discussion identified some of the required emissions testing that would be required. However, their proposed approach requires CFD modeling, which makes it difficult to evaluate the full impact of the proposed demonstration.

GE also provided a relatively detailed test plan, which clearly identified their scope, approach to testing, and requirements of PacifiCorp. Initially, GE did not include the load following demonstration testing for days 7-14, but in response to a question GE provided a cost adder to include this scope. The proposed demonstration skid requires manual adjustment and in response to a question GE indicated that this is expected to occur 10-25 times during the demonstration. GE indicated that no signal is required for the demonstration; it is unclear from the proposed approach how the load following demonstration will be tested and whether this will adjust to changing load conditions or remain stationary.

The following table summarizes S&L's scores for this criteria based on the preliminary technical evaluation:

Item	Technical Criteria	AECOM	APCS	GE
4D	Test Plan	7	6	5

Aux Power and Utility Needs

AECOM's proposal indicates that the auxiliary power consumption of the demonstration equipment will be approximately 1.7 MW. In addition, AECOM's proposal requires PacifiCorp to supply demin water and diesel fuel for pumps, compressors and lights. AECOM provided a cost adder to supply diesel fuel for pumps and a generator for the demonstration.

In response to questions, APCS provided minimal information regarding the type of utilities which would be required, including a limited quantity of water for dilution and flushing, 480V power for the small supply pumps and steam for the urea storage and injection. While APCS provided information on the type of steam that would be required (1000-1200°F), they did not indicated the quantity of steam that would be required either on an interim or continuous basis. While it is anticipated that the utility requirements would be minimal, there may be an issue with providing steam at the required consumption rate which will not be identified until after the CFD modeling is completed after award.

GE requires minimal power consumption, plant air and water be provided by PacifiCorp. All of the required reagents are being provided by GE as specified.

The following table summarizes S&L's scores for this criteria based on the preliminary technical evaluation:

Item	Technical Criteria	AECOM	APCS	GE
4E	Utility Needs	0	5	9

Schedule

AECOM provided a schedule for construction and testing of their demonstration. However, the proposed work requires a significant quantity of on-site construction work to be performed by PacifiCorp as well as an outage to modify the FGD inlet ductwork. PacifiCorp has a maintenance outage scheduled for next fall which could accommodate this work.

APCS did not provide a schedule with their initial proposal but rather referenced the schedule defined in the Specification. Questions were posed to APCS regarding their proposed test plan and schedule and their response outlined a preliminary scheduled of approximately 4-6 weeks depending on the scope. This schedule includes one week of setup, 6 days of steady state parametric testing, one week to analyze data followed by eight days of load following operation. If an additional week of load following is selected, APCS proposed another one week break prior to the additional testing to analyze data and further optimize the system. Based on the results of the CFD model, additional boiler penetrations may be required which would require an outage to install. Similar to above, this may be completed during the maintenance outage scheduled for next fall. However, if the additional boiler penetrations do not coincide with a door, boiler tube panels would need to be procured. Boiler tube panels require a relatively long lead time which could impact the ability to install them during the outage depending on when the CFD modeling is completed.

GE also requires modification to the boiler openings by adding new penetrations to accommodate their injection lances. Similar to above, this may be completed during the maintenance outage scheduled for next fall. While boiler tube panels are long lead items, GE does not require CFD modeling to identify the quantity or location, so there is minimal impact to the outage schedule expected.

The following table summarizes S&L's scores for this criteria based on the preliminary technical evaluation:

Item	Technical Criteria	AECOM	APCS	GE
4F	Schedule	7	5	7

Other Emission Sources

AECOM's proposed ozone injection requires ozone generators to be installed on-site. It is unknown what sort of permitting requirements may be associated with use of an ozone generator on-site. In response to a question, AECOM indicated that they are not aware of any additional permitting requirements associated with this technology at any of the refinery applications. However, they indicated that ozone monitors would be recommended for any enclosed spaces. It is unclear whether injection of ozone into the FGD could result in release of ozone through the FGD or oxidation of other pollutants, such as SO_2 to SO_3. While AECOM claims there will be no negative impacts to the other pollutants, this will not be known until the demonstration occurs.

APCS's proposed technology involves the injection of peroxide and urea into the boiler. Urea injection into the boiler, typical for SNCR, will result in ammonia slip leaving the boiler; however, the expected ammonia slip concentration has not been estimated by APCS. The fate of the peroxide is unknown and it is unclear whether this could increase other emissions. In response to a question, APCS indicated that they have estimated the CO emission may be as high as 2.5% of the injected urea; as the injection rate of the urea is unknown this cannot be fully evaluated.

GE's proposed technology is a variation of SNCR technology. As discussed above, SNCR technology uses urea injection into the boiler which will result in ammonia slip leaving the boiler and could impact CO emissions, though increased CO emissions have been difficult to quantify for SNCR installations in the past.

The following table summarizes S&L's scores for this criteria based on the preliminary technical evaluation:

Item	Technical Criteria	AECOM	APCS	GE
4G	Other Emissions	5	6	7

Cost of Demonstration Testing

The cost of the demonstration testing was excluded from the preliminary technical evaluation.

Cost-Sharing and/or Co-Funding Opportunities

AECOM has proposed significant co-funding from themselves and their partners; however, the co-funding comes with high risk terms ("clawback provision") requiring repayment if the technology is not purchased within two years of a successful demonstration. As it is proposed, S&L would not recommend accepting the clawback provision.

APCS indicated in their proposal that they have sought out potential co-funding opportunities as part of their proposal but were unable to secure any contributions. However, APCS did indicate that these discussions are on-going. Further, they indicated that each of the team participants has independently reduced costs in various areas but does not quantify those reductions.

GE did not provide any cost share or co-funding for the demonstration.

The following table summarizes S&L's scores for this criteria based on the preliminary technical evaluation:

Item	Technical Criteria	AECOM	APCS	GE
4I	Cost-Sharing and/or Co-Funding	3	1	0

Preliminary Technical Evaluation Recommendation

As discussed above, FuelTech was eliminated from the evaluation as their proposed technology does not meet the criteria of the STEP initiative.

The following table summarizes the evaluated score for each of the remaining bidders.

Item	**Technical Criteria**	**AECOM**	**APCS**	**GE**
---	TOTAL	39	35.5	45
	RANK	2	3	1

Bid Evaluation Matrix - SUBSIDIARY NAME-PROJECT NAME-LOCATION-Doc

Evaluator makes changes in the orange shaded cells and enters the rating in the yellow shaded cells. Revise and hide/unhide columns and rows to suit the project.

% Weight	Technical Assessment Criteria		1 AECOM	2 APCS	3 GE Alstom
1	Go / No Go	Testability (Is the proposed technology testable at Huntington)	Yes	Yes	Yes
2		Is stack testing included in proposal (A NO GO does not mean exclusion)	Yes	Yes	Yes
2		Does the proposed technology satisfy the STEP Initiative criteria for demonstration?	Yes	Yes	Yes
3		Technical 4: Not Used:			
4	S&L	A. Demonstration Test Expected NO_X Reduction related to Permit Limit (30-day rolling average): Scale: 1 point per 0.01 lb/MMBTU NO_X reduction.	10.00	8.00	4.00
		B. Plant Modification Required: Scale 0-2 for permanent modification that affect plant operation and major changes required to plant power and/or water system, 3-5 for permanent modification or major changes to plant power and/or water systems that do not affect plant operation, 6-8 for temporary and removable modifications, 9-10 for no modifications	2.00	4.00	4.00
		C. Technology Implementation History: Has the technology been implemented before on other coal fired boilers. Scale: Technology has never been implemented or used 0-2, Technology only been utilized in bench testing 3-4; Technology has been utilized in slip stream pilot testing 5-6; Technology has been utilized on a full-scale boiler 7-8; Technology has been permanently installed/utilized on at least one coal fired utility boiler 9-10. NOTE: reduction of 2 point for known technologies that are not innovated to the coal fired utility boiler.	5.00	4.00	9.00
		D. Detail Work and Test Plan: Has the respondent provided sufficient information to demonstrate their understanding of the scope of the RFP and provided information so the company can make a informed decision regarding test modifications and equipment. Has the respondent met the criteria of the RFP. Scale: Demonstrates marginal understanding and information 1-3; Demonstrates adequate understanding and information 4-6; Demonstrates not only understanding of requirements but shows additional though, creativity and understanding of risks and issues 7-10.	7.00	3.00	5.00
		E. Auxiliary Power and Utility Needs: Do the utilities required for the demonstration test pose a risk to operation of the unit. Be it auxiliary power consumption, demineralized water, steam or other. Scale: Rank based on cost of utilities to plant for demonstration. Highest costs for supply reagent(s), power, water, etc. 0-3; Additional costs for reagent(s) 4-7; Lowest cost (i.e. bringing a generator) 8-10.	0.00	5.00	9.00
		F. Schedule: Has the respondent submitted a schedule that the company can utilize for scheduling of demonstration testing; Scale: No schedule provided 0; provided high level schedule with limited duration information 0-3; provided schedule with enough information to plan demonstration test 3-7; provided schedule detailed enough for company planning of demonstration test 8-10	7.00	5.00	7.00
		G. Other Emission Sources Created from Test: Will the reagent used in the test cause other regulated emissions to be generated. Scale: New source pollutants created 1-3; additional non-regulated emissions created 4-7; No new emissions created 8-10	5.00	6.00	7.00
		H. Cost of Demonstration Testing: Pricing varies significantly based on estimated time on-site for contractor's personnel, cost of demonstration equipment, whether or not demonstration testing requires a testing contractor to be hired, etc. Scale: Rank based on price. Highest cost 1-3; Moderately priced 4-7; Lowest cost 8-10			
		G. Cost-Sharing and/or Co-Funding Opportunities: Scale: Rank based on amount of cost-sharing. No cost-sharing/co-funding 0; provided small cost-sharing amount with limitations (such as schedule, contract negotiations, etc.) 1-3; provided cost-sharing amount without limitations 4-7; provided largest amount of cost-sharing without limitations 8-10	3.00	1.00	0.00

To: Chad Teply

From: Mike Saunders
Richard Goff

Cc: Glen Pinterich
Larry Bruno
Greg Betenson
Quinn Healy
Mark Rutherford
Michael Dayton
DeAnne Garcia

Date: January 12, 2018

RE: Utah Sustainable Transportation and Energy Program Alternative NO_X Technology Demonstration Test

Introduction:

This memorandum recommends that the Utah Sustainable Transportation and Energy Program ("STEP") Alternative Nitrogen Oxides ("NO_X") Technology Demonstration Test be deferred in support of funding other STEP projects. The evaluation team has completed a competitive request for proposals ("RFP") from four NO_X control technology vendors. The four vendors were evaluated and none were capable of meeting the project's objectives below within budget:

1. Assess alternative options for implementation of one or more NO_X reduction technologies that in combination achieve similar emissions rates expected from a Selective Catalytic Reduction ("SCR") system.

2. Select one or more NO_X emissions technologies that appear to be capable of meeting the primary objective, and where indicated and further testing is required, install a slip stream or full stream demonstration of the technology.

3. Assess the economic feasibility of full scale implementation of the technologies compared to other available NO_X emissions control options for Hunter and Huntington plants.

Two of the evaluated vendors meet these objectives, but there testing costs were not within the budget set under the Utah STEP program. The other two vendors did not meet the innovation or the emerging technology objective.

The remainder of this memorandum summarizes the Company's evaluation of the vendors proposed technologies, provided a technical summary, presents a company of the proposal, offers a recommendation and lists anticipated next steps.

Evaluation Process for Short-Listed Bidders

The evaluated vendors were selected from the results of a Company issued request for information ("RFI") process. The vendors selected for the short-list RFP were picked from the RFI responses. The Company then issued a RFP for performing a technology demonstration test on Huntington Unit 1. The Company then evaluated the RFP responses using a project team agreed upon and pre-approved evaluation matrix. Each vendor was evaluated on the criteria listed in Table 1.

Table 1: Demonstration Test RFP Evaluation Criteria

Description / Criteria	**Scoring Parameter**
Price and pricing schedule	Least Cost Provider
Technology compatible with Huntington Power Plant	Go / No Go
STEP initiative criteria met	Go / No Go
Demonstration test expected NO_X reduction related to permit limit (30-day rolling average):	1 point per 0.01 lb./MMBTU NOX reduction
Plant Modifications Required	Rating Scale: 0-2 for permanent modification that affect plant operation and major changes required to plant power and/or water systems; 3-5 for permanent modification or major changes to plant power and/or water systems that do not affect plant operation; 6-8 for temporary and removable modifications; 9-10 for no modifications
Technology Implementation History: Has the technology been implemented before on other coal fire boilers?	Rating Scale: Technology has never been implemented or used 0-2; Technology only been utilized in bench testing 3-4; Technology has been utilized in slip stream pilot testing 5-6; Technology has been utilized on a full scale boiler 7-8; Technology has been permanently installed/utilized on at least one coal fired utility boilers 9-10.
Detail Work and Test Plan: Has the respondent provided sufficient information to demonstrate their understanding of the scope of the RFP and provided information so the company can make an informed decision regarding test modifications and equipment. Has the respondent met the criteria of the RFP?	Rating Scale: Demonstrates marginal understanding and information 1-3; Demonstrates adequate understanding and information 4-6; Demonstrates not only understanding of requirements but shows additional though, creativity and understanding of risks and issues 7-10.

Auxiliary Power and Utility Needs: Do the utilities required for the demonstration test pose a risk to operation of the unit (be it auxiliary power consumption, demineralized water, steam or other)?	Rating Scale: Rank based on cost of utilities to plant for demonstration. Highest costs for supply reagent(s), power, water, etc. 0-3; Additional costs for reagent(s) 4-7; Lowest cost (i.e. bringing a generator) 8-10.
Schedule: Has the respondent submitted a schedule that the company can utilize for scheduling of demonstration testing?	Rating Scale: No schedule provided 0; provided high level schedule with limited duration information 0-3; provided schedule with enough information to plan demonstration test 3-7; provided schedule detailed enough for company planning of demonstration test 8-10
Other Emission Sources Created from Test: Will the reagent used in the test cause other regulated emissions to be generated?	Rating Scale: New source pollutants created 1-3; additional non-regulated emissions created 4-7; No new emissions created 8-10

The commercial and technical sections of the evaluation matrix were weighed at 50 percent each towards the complete evaluation. The vendors were requested to supply a proposal based on the technology provided in RFI. The short-listed vendors and requested test technology is listed in Table 2.

Table 2: Invited RFP Vendors and Requested Test Technology

Vendor	Technology
GE / Alstom	Umbrella Selective Non-Catalytic Reduction ("SNCR")
APCS	Advance SNCR (50% Urea and 50% Hydrogen Peroxide)
Fuel Tech	SNCR (Urea Injection)
AECOM	LoTOx^{TM} (Ozone injection)

SNCR's vendors were added to the RFP as a price check against emerging technology. The RFP was issued on August 4, 2017 and responses were received on October 9, 2017.

Technical Summary

The technical evaluation was performed by a team consisting of Sargent and Lundy (acting as owner's engineer), the Huntington engineering manager, and the Advanced NOx Control Technology project manager. Attachment A to this memorandum contains the evaluation matrix and Sargent and Lundy's technical evaluation. Table 3 below outlines the final technical scoring of the four vendors.

Table 3: Final Technical Evaluation Summary

Rank	**Vendor / Technology**	**Technical Score**
1	General Electric (Umbrella SNCR)	9.56
2	AECOM (Ozone Injection)	8.80
3	APCS (Peroxide and Urea injection)	7.49

4	Fuel Tech (traditional SNCR)	N/A

A technical evaluation summary is listed below of the NO_X reduction level, major concerns and issues with the vendor proposals.

Common to all vendors:

- All evaluated vendors require an outage in which to install modifications to the boiler or flue gas path ductwork and to install additional material required for testing. The outage requirement can be achieved during Huntington's fall 2018 overhaul.
- Company to provide water, electricity, and testing support. The level of required support varies with vendor.

General Electric

- SNCR technology proposed by General Electric is not considered an emerging technology in the utility industry. However, General Electric's approach was considered innovative enough to warrant further evaluation.
- General Electric predicts a 30 percent reduction in NO_X emissions with the Umbrella SNCR.
- Umbrella SNCR's have been installed in coal fired boilers outside of the United States.
- General Electric did not provide load following capability for the test demonstration. If load following is pursued by the Company, then additional cost would be added to the testing.
- Injection of Urea could impact carbon monoxide emissions and could create ammonia slip issue.

AECOM

- AECOM's ozone injection met the STEP requirements and is considered innovative and emerging.
- AECOM predicted a 70 percent reduction in NO_X emission that is capable of meeting SCR type performance.
- Significant and permanent modifications to the existing facility are required for the AECOM test. The work is to be carried out by the Company and at its cost. This work includes, but is not limited to, installation of injection ports, lining of the flue gas path ductwork, installation of distribution baffles, auxiliary power modifications, piping, supports, cooling water supply, and supply of oxygen for testing.
- AECOM requires approximately 1.7 Megawatts of power to operate the ozone generator.
- Ozone injection has not been tested previously at this scale.
- It is unknown if the injection of ozone into the flue gas desulphurization system would result in a release of other pollutants such as SO_2 and SO_3.

- AECOM's co-funding support includes a "claw-back" provision in which if the Company does not install a full scale system within two years then an additional charge would be applied.

APCS

- APCS estimates a 60 percent reduction in NO_X emissions with the peroxide urea injection.
- Modifications to the unit includes use of sootblower openings and new boiler water wall openings for injection locations. Additional injection locations would be identified after a computational fluid dynamic model is performed.
- The injection medium has not been tested beyond bench scale phase.
- Minimal information was received as to the water and power requirements needed for the demonstration test. APCS does require auxiliary steam in the temperature range between 1,000 - 1,200°F.
- Injection of Urea could impact carbon monoxide emissions and ammonia slip.

Fuel Tech

- SNCR technology proposed by Fuel Tech is not considered an innovative or emerging technology and is widely implemented throughout the utility industry. A decision was made to exclude Fuel Tech from consideration as it doesn't meet the STEP innovation criteria.
- Fuel Tech's technical and commercial proposal additionally did not meet other RFP requirements.

Commercial / Cost Summary

The budget for the Advance NO_X control emission technology STEP program is $1.415 Million. Currently, the project has committed approximately $225,000 in owner's engineer and other costs. Company labor cost are being held under a separate STEP order. The remaining amount of $1.190 Million is available for the demonstration testing. Table 4 below summarizes the initial proposal cost provided by the vendors plus a proposal adder to conform to the performance specification. The proposal adders are based off responses to RFP questions issued to the vendors for proposal clarifications.

Table 4: **Demonstration Test Cost Summary**

Vendor	**Initial Proposal**	**Proposal adder to Conform**	**Total**
General Electric	$1,085,585	$376,298	$1,461,883
AECOM	$2,344,000	$2,070,900[1]	$4,414,900
APCS	$3,476,875	Undetermined	$3,476,875
Fuel Tech	$430,000[2]	Undetermined engineering costs	$430,000

[1] Includes claw-back provision amount

[2] Fuel Tech initial proposal cost is based off their RFI response. Fuel Tech declined to provide a full RFP response.

Based on the provided cost from the vendors, only Fuel Tech, which was eliminated technically, was low enough to perform a demonstration test with the funding available. It is anticipated that there will be additional costs from APCS to perform the test once the design is completed. The General Electric testing price could be reduced if the Company decides to forgo the load following testing provision requested in the RFP. If not, then Company would only know how the SNCR performs at full load and low load.

Based on the above proposals General Electric was the only vendor that was close to the STEP budget. The remaining vendors were well above budget and Fuel Tech did not meet the STEP requirements.

Recommendation

Each of the vendors that supplied a proposal fell short in meeting both the commercial and technical requirements. Table 5 summarizes the evaluation on both a commercial and technical side.

Table 5: Commercial and Technical Evaluation Summary

*Legend: (-) borderline acceptable, x – does not meet requirements, ✓ - meets requirement

Vendor	Commercial	Technical	Overall
General Electric	-	-	-
AECOM	x	✓	X
APCS	x	✓	X
Fuel TECH	✓	x	X

Upon review of the commercial and technical evaluation, it is recommended that the Company forgo the alternative NO_X emission control technology demonstration test and utilize the target STEP funding to further support one or multiple other STEP projects. Utilizing the STEP funds on other projects would be of a higher value to the Company's customers than performing a demonstration test with a technology that is already well established like SNCR.

Next Steps

The following is are the next steps identified for the project:

- Approach the Utah Public Service Commission with a formal request to utilize STEP funds for one or more of the other STEP projects.
  - The recommended additional funding projects:
    - Phase II of the Carbon SAFE work;
    - Further biomass firing; or
    - Further carbon dioxide cryogenic capture support.

- Complete the technical report summarizing the cost for a full scale implementation of the Alternative NO_X emission control technology.

Attachments:

Attachment 1: Sargent and Lundy Technical Evaluation, November 16, 2017.

STEP Project Report

Period Ending: December 31, 2017

STEP Project Name: Utah STEP Study Evaluation for CO2 Enhanced Coal Bed Methane Recovery

Project Objective:

The project is to perform a feasibility study to evaluate opportunities to use carbon dioxide (“CO_2”) for beneficial use for enhanced natural gas recovery from coal seams, specifically coal seams in the Emery County area. As part of the study, an assessment will be made of the capability of local coal seams to concurrently sequester CO_2.

Project Accounting:

Cost Object	2017
Annual Collection (Budget)	$0.00
Annual Spend (Capital)	$0.00
Committed Funds	$0.00
Uncommitted Funds	$0.00
External OMAG Expenses	$0.00
Subtotal	$0.00

Project Milestones:

Project Milestone	Delivery Date	Status
Notice to Proceed Start Date	January 1, 2018	Completed
Contracts with PacifiCorp Complete	January 31, 2018	Completed
Draft Test Program Submitted	January 31, 2018	Completed
Revised Program Submitted	February 15, 2018	Delayed
Annual Report 1 Presented and Submitted	January 31, 2019	On Target

Annual Report 2 Presented and Submitted	January 31, 2020	On Target
Annual Report 3 Presented and Submitted	January 30, 2021	On Target
Develop Concept for Future In-situ Pilot Testing	July 1, 2021	On Target
Final Report Presented and Submitted	October 31, 2021	On Target

Program Benefits:

The benefits of the project will be a technical, economic and environmental study on the costs and benefits of injecting coal fired power plant derived CO_2 for enhanced methane recovery from underground coal beds. The study will also determine whether the Emery County coal beds are conducive to enhanced methane recovery using CO_2. Deliverables will also include proposing technologies and strategies for improving CO_2 injection efficiency. The University will also study the risk of induced seismicity due to the CO_2 injection.

The deliverables above benefit the Rocky Mountain Power's customers by utilizing STEP funding to study increasing the efficiency of energy production while simultaneously decreasing CO_2 emissions. When the benefits of the study are combined with other studies and work being conducted under the STEP program, sufficient knowledge about carbon sequestration is gathered for potential future use.

Potential future applications for similar projects:

When combined with the results of the STEP CarbonSAFE project and the STEP cryogenic carbon capture demonstration, Rocky Mountain Power would have sufficient information to start to develop a strategy for carbon sequestration in Utah. Additionally, information gathered from the study can be utilized to develop further understanding of potential enhance energy recovery in Utah with simultaneous carbon dioxide sequestration.

Cryogenic Carbon Capture - STEP Project Report

Period Ending: December 31, 2017

STEP Project Name: Cryogenic Carbon Capture (CCC) Demonstration

Project Objective:

The objective of this project is to continue the development and demonstration of the promising Cryogenic Carbon Capture technology.

This Scope of Work is divided into two primary phases. The first, called the Development Phase, involves research to be performed by Contractor into specific areas where it is believed efficiency, reliability, or overall performance of the process can be improved. The Contactor's recommendations and experimental results will then be used to make changes and enhancements to the skid demonstration unit provided as part of this Scope of Work. On-site preparations by the Contractor of the testing area, most likely the Hunter Power Plant in central Utah, will also be conducted during this time. The Field Demonstration Phase will then use this demonstration unit at the site during an extended test run over approximately five to six months. The Contactor's development work will take place during 2017 and early 2018 with the field testing beginning in late 2018.

These phases will be conducted by Contactor in parallel with a proposed DOE project to mature the technology and gather critical information in preparation for a scale-up.

Project Accounting:

Cost Object	**2017**
Annual Collection (Budget)	$356,557
Annual Spend (Capital)	$0.00
Committed Funds	$0.00
Uncommitted Funds	$0.00
External OMAG Expenses	$160,451
Subtotal	$160,451

Project Milestones:

Project Milestone	Delivery Date	Status
Sustainable Energy Solutions (SES) will deliver a report containing the basic designs for both a self-cleaning heat exchanger and the experimental dual solid-liquid separations system. SES will also begin purchasing equipment for these systems.	6/15/2017	Completed
SES will deliver a report containing the following: - The final designs, documentation of parts ordered, and initial tests of the experimental alternate refrigeration system. - The final designs and documentation of parts ordered of the experimental self-cleaning heat exchanger. - The design, documentation of parts ordered and installation of equipment for pre-treatment of real flue gases and dual solid-liquid separations.	8/15/2017	Completed
SES will deliver a report containing the following: - The purchase orders and initial test reports of improved instrumentation such as advanced cryogenic flow measurement and output measurement. - Results of testing for the experimental integrated system with simulated flue gas at minimum 1/4 tonne per day CO2 - Results of testing of the experimental integrated system tested with real flue gas.	11/15/2017	Completed
SES will deliver a report containing the following: - Designs and documentation of parts ordered for permanent skid-scale unit ops, including HX's, dryers, separations.	2/15/2018	Completed
SES will deliver a report containing the following: - Documentation of parts ordered for permanent skid-scale unit ops and skid integration. - Results of testing the permanent skid system with simulated flue gas at 1 tonne/day. - Shakedown testing completed.	5/15/2018	On Target
SES will deliver a report containing the following: - A description of the preparations and modifications at the Hunter PP site. - Documentation of insurance, transport, personnel trailer, and other on-site needs. - A description of the ongoing on-site setup and shakedown of the ECL testing skid.	8/15/2018	On Target

SES will deliver the following: - Finalized setup and operation of the ECL Skid at the Hunter PP. - A full report of the testing to-date under RMP funding, with continued testing occurring under the NETL contract.	11/15/2018	On Target

Program Benefits:

The benefits are validating a technology that can capture carbon dioxide gas at an economically viable cost. Such a technology would be beneficial by proving the ability to reduce carbon dioxide emissions. The demonstration test would allow the Company to evaluate the ability of SES's CCC technology to meet these goals.

Potential future applications for similar projects:

Third party engineering services will be procured in 2018 to assess the scalability of the technology for complete processing of flue gas at utility power plants.

STEP Project Report

Period Ending: December 31, 2017

STEP Project Name: Utah STEP CarbonSAFE Pre-Feasibility Study – Phase 1

Project Objective:

The Company co-funded participation in a University of Utah pre-feasibility study to evaluate the development of commercial scale carbon capture and sequestration ("CCS") storage in Utah. The pre-feasibility study is being performed under Funding Opportunity Announcement (FOA Number DE-FOA-00001584) and is known as the Carbon Storage Assurance Facility Enterprise ("CarbonSAFE").

Project Accounting:

Cost Object	2017
Annual Collection (Budget)	$150,000
Annual Spend (Capital)	$0.00
Committed Funds	$0.00
Uncommitted Funds	$0.00
External OMAG Expenses	$150,239
Subtotal	$150,239

Project Milestones:

Project Milestone	Delivery Date	Status
Project Kick-off	July 10, 2017	Completed
Quarterly Report	December 31, 2017	Completed
Technology Assessment Completed	December 31, 2017	Completed
Phase II – Application Submission	February 28, 2018	Completed
Quarterly Report	April 31, 2018	On Target
Final Report Presented and Submitted	July 1, 2018	On Target

Program Benefits:

The CarbonSAFE STEP funding was part of a larger funding initiative from the Department of Energy of $1.2 million for conducting a pre-feasibility study into a developing a commercial scale carbon dioxide storage reservoir. The participation into the study has resulted in a high level cost estimate as to the cost to construct a carbon dioxide capture facility at one of the existing Utah coal fired power plants. The pre-feasibility study along with the high level cost estimate provides information to the Company to determine if carbon dioxide capture is feasible in Utah.

Potential future applications for similar projects:

Pending the results of the pre-feasibility study. A potential large carbon dioxide storage reservoir in Utah, the next step would be to conduct a feasibility study. The feasibility study would be part of the Phase II CarbonSAFE funding opportunity from the Department of Energy.

STEP Project Report

Period Ending: December 31, 2017

STEP Project Name: Feasibility Assessment of Solar Thermal Integration – Hunter Plant

Project Objective:

This project will investigate the potential of integrating solar thermal collection to provide steam and/or feedwater heating into the Hunter 3 boiler/feedwater cycle. Integration of a solar thermal collection system would have a benefit of minimizing coal consumption and the attendant emissions associated with reduced coal use. The study would focus on the application of parabolic solar troughs and would also consider power tower collections systems.

Factors that will be evaluated in the study are:

- Site specific costs and benefits of solar thermal integration at the Hunter Plant
- Steam/feedwater injection points in the boiler feedwater cycle and those impacts on performance
- Impact on coal consumption and associated emissions
- Land requirements

Project Accounting:

Cost Object	2017
Annual Collection (Budget)	$0.00
Annual Spend (Capital)	$0.00
Committed Funds	$0.00
Uncommitted Funds	$0.00
External OMAG Expenses	$0.00
Subtotal	$0.00

Project Milestones:

Project Milestones	Delivery Date	Status
Contract between BYU and PacifiCorp complete (Assumed start date)	1/1/2019	On Target

Contract between Owner’s Engineer and PacifiCorp complete	3/2/2019	On Target
Commencement Study	5/1/2019	On Target
Draft of proposed study objectives	5/31/2019	On Target
Final proposed study objectives	6/30/2019	On Target
Solar resource study draft complete	7/31/2019	On Target
Land resource study draft complete	12/30/2019	On Target
Select steam/feedwater injection points	4/30/2020	On Target
Cycle efficiency draft calculations complete	6/29/2020	On Target
Coal consumption offset and solar augmentation cost estimates draft complete	12/29/2020	On Target
Draft final report submitted	2/28/2021	On Target
Final report submitted	6/26/2021	On Target

Program Benefits: To be determined

Potential future applications for similar projects: To be determined

Note:

Project is on schedule and set to begin in 2019.

STEP Project Report

Period Ending December 31, 2017

STEP Project Name: Circuit Performance Meters (Substation Metering)

Project Objective:

Deploy an advanced substation metering program that includes installing advanced metering infrastructure on approximately fifty circuits connected to distribution substations in Utah where limited or no existing communications exist. This project will enable higher data visibility on the distribution system by providing for the installation of advanced meters, setting up remote communication paths with all installed meters and the purchase of a data management and analytics tool to automatically collect, analyze, interpret and report on the available data.

Project Accounting:

	2017
Annual Collection (Budget)	$110,000
Annual Spend (Capital)	$13,676
Committed Funds	$0
Uncommitted Funds	$0
External OMAG Expenses	$0
Subtotal	$13,676

The 2017 budget variance was affected by:

1. not executing the contract for the data analytics software in 2017. Contract was awarded in March 2018.
2. the budget allowed for meter installation at 3 sites, estimated at $20,000 per site; 2 sites were completed for a combined cost of $13,676

Project Milestones:

Milestones	**Delivery Date**	**Status/Progress**
Complete 2 pilot sites in 2017	December 31, 2017	The 2 pilot sites were completed by December 31, 2017.
Execute contract for data anlaytics software	December 31, 2017	A vendor was selected in December 2017 but due to a delay caused by contract negotiations, contract was awarded in March 2018.
Install metering on 25 circuits in 2018	December 31, 2018	On track to install metering on 25 circuits in 2018.

Install metering on 23 circuits in 2019	December 31, 2019	On track to install metering on 23 circuits in 2019.

Key Challenges, Findings, Results and Lessons Learned:

Description of Investment	Anticipated Outcome	Challenges	Findings	Results	Lessons Learned
a.					
b.					
c.					

Program Benefits

- Enable increasing levels of distributed energy resources on the power grid in an affordable and reliable way by providing increasing visibility on loading levels, load shape, and event information needed to develop thorough interconnection studies and hosting capacities for customers, determining safe switching procedures and cost effective capital improvement plans.
- Assists in preventing load imbalance on a distribution circuit caused by single phase distributed energy resources which can result in three phase voltage imbalance issues and increasing potential for unintended circuit breaker operations from elevated neutral currents.
- Understand harmonic issues caused by distributed energy resources and take appropriate steps to resolve issues, if any, in a proactive way.
- Improve optimization opportunities for capital costs and system losses by providing measurements of per-phase vector quantities for voltage and current.
- Identify service quality issues early and allow timely development and implementation of cost effective mitigation.
- Enhance understanding of intermittent generation resources and their impact on the power grid.
- Reduce time delays of approvals for customers seeking distributed generation interconnections.
- Provide customers with circuit information with a higher level of accuracy.
- Identify and control risks associated with the integration of significant penetration of distributed energy resources. This includes controlling claims from power quality issues, customer equipment failure, utility/customer equipment damage or impact on customer generation levels.

Potential future applications for similar projects:

There is the potential to install advanced metering devices on all circuits with limited or no communications regardless of the existence of distributed energy resources on those circuits.

STEP Project Report

Period Ending December 31, 2017

STEP Project Name: **Commercial Line Extension Pilot Program**

Project Objective:

Incentivise developers of commercial/industrial property to install electrical backbone within their developments, and provide for Plug-in Electrical Vehicle charging stations.

Project Accounting:

	2017
Annual Collection (Budget)	$500,000
Annual Spend (Capital)	
Committed Funds*	$16,905
Uncommitted Funds	--
External OMAG Expenses	--
Subtotal	$0.00

*$16,905 was committed in 2017, but not paid until 2018.

Project Milestones:

The Commercial Line Extension Pilot Program is applied each time a commercial or industrial developer requests installation of primary voltage backbone facilities within their development. There are no specific project milestones. Rather each development is independent, and is initiated when the developer makes the request for service. Funds are transferred to the individual job upon the developer paying their share of the cost of the development.

Key Challenges, Findings, Results and Lessons Learned:

2018 will be the first complete year of this program, and the first year where the program was available in the early months of the year when construction projects are typically initiated.

Program Benefits

As developers request full backbone installation within their developments, the number of build ready commercial and industrial lots will increase. This is opposed to lots where electricity has to be brought to the lots from some distance away, right-of-ways obtained, road crossing permits obtained, public utility easement clearances to previously installed other utility resolved, and any other electrical construction off-of-the-lot problem resolved.

As developers provided full development design information, the electrical grid serving the area can be better engineered. This leads to greater reliability and less capacity upgrade work of already installed facilities, which by nature is more expensive than intial contstruction where there are fewer removals of existing facilities and better access to right-of-ways.

To the extent developers do construction within their developments, sites for PEV charging will be identified and power made available to those locations. This will contribute to the environmental benefits of EV use.

Potential future applications for similar projects:

This program will give experience in this type of incentive to developers. This understanding will add understanding to what works and what more may be needed for efficient upfront design of commercial and industrial developments and siting of electrical infrastructure supporting such areas.

Attachments:

The Commercial Line Extension Pilot Program document

Commercial Line Extension Pilot Program
of the
Sustainable Transportation and Energy Program (STEP)

Description of the Program

The Commercial Line Extension Pilot Program, Regulation No. 13, is part of Rocky Mountain Power's Utah Sustainable Transportation and Energy Plan ("STEP"). It provides a line extension allowance for commercial or industrial developers within the boundaries of their development. It also applies to the non-residential portion of a mixed residential and non-residential development. One of the provision of Regulation No. 13 is the requirement for parking spaces allocated for electrical vehicle charging.

Background

Commercial development in Utah has increased due to the improving economy, and at the same time developers face competitive pressure from each other. With that has come an increasing resistance by developers towards Rock Mountain Power's line extension costs for electrical facilities inside developments. An increasing number of commercial developers work around the line extension requirements to reduce the developer's cost of electrical infrastructure. They do this by developing projects in small phases when they have a customer willing to fund the backbone costs with their (the customer's) line extension allowance. They also minimizing the size of and extent of facilities to be built by requesting just enough for a portion of the development, rather than providing information on the full extent of the development. This results in multiple trips and piecemeal installation of backbone facilities within the development. This has the potential of a less than optimal design within the development since the full build out of the development is not known.

The commercial line extension allowance will offset a portion of those costs providing an incentive for developers to look at long term build out of their development and fund facilities to meet their long term needs.

Components and Benefits of the Pilot Program

1. Regulation No. 13 provides a commercial developer allowance of 20% of the construction cost of backbone electrical facilities inside the development.
2. This allowance will aid in economic development and growth of commercial businesses by incenting developers to install backbone with their developments which makes it more affordable for new business to locate in the development, thus increasing overall business vitality.
3. The allowance is simple to apply. It is a straight 20% of the backbone cost. This simplicity should reduce confusion and incent construction of facilities to meet full build out of the development and effective integration into the electrical system.
4. Aligns with residential development allowance, meaning in a mixed development with both non-residential and residential, both are applied, each towards their respective share of the costs.

5. The allowance is STEP funded. As such it is a contribution in aid of construction toward the cost of electrical infrastructure. It will have no impact on RMP capital budgets, or O&M budgets.
6. The allowance is conditional on the developer allocating space in parking areas for PEV charging, and installing conduit to that location for installation electrical supply for PEV chargers. The developer may apply for assistance in installing the PEV chargers by applying and complying with requirements to receive funding through the STEP Electric Vehicle program.
7. $500,000 per year is the anticipated spend for commercial line extension allowances. Funding will be provided until $2,500,000 is expended, or the expiration of the five year STEP program, whichever comes first.

Project Implementation

The Commercial Line Extension Pilot Program, Regulation No. 13, was filed on June 6, 2017. This was well into the construction season, well after line extension requests for developments are typically submitted and contracted for. In 2017 only three developments were contracted for after that that date.

Outreach is being made in 2018 to the developer community. 2018 will be the first full year for this program and will be a much better measure of the program.

STEP Project Report

Period Ending: December 31, 2017

STEP Project Name: Gadsby Emissions Curtailment

Project Objective:

To help improve air quality, the Gadsby Emissions Curtailment program offers a process where the Gadsby Power Plant would curtail its emissions during winter inversion air quality events as defined by the Utah Division of Air Quality ("UDAQ"). The UDAQ issues action alerts when pollution is approaching unhealthy levels. These alerts proactively notify residents and businesses before pollution build-up so they can begin to reduce their emissions. When pollution levels reach 15 µg/m3 for PM2.5, DAQ issues a 'yellow' or voluntary action day, urging Utah residents to drive less and take other pollution reduction measures. At 25 µg/m3, 10 µg/m3 below the EPA health standard, DAQ issues a "red" or mandatory advisory prohibiting burning of wood and coal stoves or fireplaces. It is at the 25 µg/m3 level when RMP will take action to curtail the Gadsby Steam units.

Project Accounting:

Cost Object	2017
Annual Collection (Budget)	$100,000
Annual Spend (Capital)	$0.00
Committed Funds	$0.00
Uncommitted Funds	$0.00
External OMAG Expenses	$0.00
Subtotal	$0.00

In 2017 during DAQ posted air quality events it was not economic for Gadsby to operate thus no STEP funds were utilized.

Project Milestones:

Project Milestones	Delivery Date	Status/Progress

Key Challenges, Findings, Results and Lessons Learned:

Challenges	Anticipated Outcome	Findings	Results	Lessons Learned

Program Benefits:

Many of the company's customers live in communities that are located within the non-attainment areas, including Salt Lake City which is where the Gadsby Power Plant is located. The primary benefit of curtailing Gadsby is the potential reduction of NOx emissions which contribute to the formation of PM 2.5. According to DAQ (see Appendix 1), the Gadsby's Power Plant may emit 0.437 tons of NOx per day during a typical winter inversion day, which makes Gadsby the 10th largest emitter of NOx in the Salt Lake non-attainment area. This program would ensure that those emissions would not occur during periods of unhealthy air quality and not contribute pollutants to air sheds of non-attainment areas.

Potential future applications for similar projects:

STEP Project Report

Period Ending December 31, 2017

STEP Project Name: Battery Storage - Panguitch Solar and Energy Storage Project

Project Objective:

Rocky Mountain Power will install a five (5) megawatt-hours battery energy storage system to resolve voltage issues on the Sevier–Panguitch 69 kilovolt transmission line. Panguitch substation is fed radially from Sevier, and all capacitive voltage correction factors have been exhausted.

To correct the voltage issues experienced during peak loading conditions, a stationary battery system will be connected to the 12.5 kilovolt distribution circuits that are connected to Panguitch substation. This reduces the loading on the power transformer and improves voltage conditions. The system will be sized to handle the voltage corrections as load grows in the area.

Project Accounting:

	2017
Annual Collection (Budget)	$500,000
Annual Spend (Capital)	$331,995
Committed Funds	$331,995
Uncommitted Funds	
External OMAG Expenses	
Subtotal	$331,995

Project Milestones:*

Milestones	Delivery Date	Status/Progress
Award an engineering, procurement and construction (EPC) contract.		Pre-bid meeting scheduled for 4/17/2018.
Prairie Dog Permit	July 30, 2018	US Fish & Wildlife to release a prairie dog conservation and permitting plan/instruction by April 30, 2018. Upon this release the Company will submit a praire dog application.
Small Generation Interconnection Agreement – Finalized	June 2018	Currently the team is working complting the Facility Study stage of the SGIA process.
EPC Design Complete	TBD	Dates to be updated after EPC contractor awarded.

EPC Major Equipment Deliviered	TBD	Dates to be updated after EPC contractor awarded.
Construction Complete	TBD	Dates to be updated after EPC contractor awarded.
Commercial Operation Date	TBD	Dates to be updated after EPC contractor awarded.

Key Challenges, Findings, Results and Lessons Learned:

Description of Investment	Anticipated Outcome	Challenges	Findings	Results	Lessons Learned
a. N/A	N/A	N/A	N/A	N/A	N/A
b. N/A	N/A	N/A	N/A	N/A	N/A
c. N/A	N/A	N/A	N/A	N/A	N/A

Project Benefits

- The loading on the 69–12.5 kilovolt power transformer at Panguitch substation will be reduced thereby ensuring the line voltage on the Sevier–Panguitch 69 kilovolt transmission line does not drop below 90% and will defer the traditional capacity increase capital investment beyond fifteen years when using present growth rates in this area.
- Enables the Company to get first-hand operational experience with control algorithms and efficiency levels associated with energy storage combined with solar. This gained experience will prepare the company in advance of large scale integration of such technology that are now becoming readily available options for customers as energy storage price declines.
- Enables the Company to become familiar with and utilize innovative technologies to provide customers with solutions to power quality issues.

Potential future applications for similar projects:

Depending on the outcome of the installation and operation a this solar-battery system there could be a number of applications across Rocky Mountain Power’s system on long radial feeds such as at Panguitch that would provide economic deferral of an major transmission rebuild.

STEP Project Report

Period Ending December 31, 2017

STEP Project Name:

Microgrid Project

Project Objective:

Deploy a microgrid demonstration project at the Utah State University Electric Vehicle Roadway (USUEVR) research facility and test track to demonstrtate and understand the ability to integrate generation, energy storage, and controls to create a microgrid.

Project Accounting:

	2017
Annual Collection (Budget)	N/A
Annual Spend (Capital)	N/A
Committed Funds	N/A
Uncommitted Funds	N/A
External OMAG Expenses	N/A
Subtotal	N/A

Project Milestones:

Milestones	Delivery Date	Status/Progress
Data collection and EVR characterization	06/30/2018	Installed smart meter and started analyzing the EVR load profiles
Preliminary microgrid planning tool	09/30/2018	Started review of the existing planning tools
Microgrid layout and test plan	12/31/2018	Planning layout of the EVR microgrid
Deploy microgrid system at EVR	04/30/2019	
Optimize planning tool for microgrid	08/31/2019	
Apply planning tool to HAFB microgrid	12/31/2019	
Create fact sheet for planning tool	4/30/2020	
Recommendations to DERs interconnection policy	06/30/2020	

Key Challenges, Findings, Results and Lessons Learned:

Description of Investment	Anticipated Outcome	Challenges	Findings	Results	Lessons Learned
a.					

b.					
c.					

Program Benefits

- Qualifies the viability of operating a microgrid on the Company's distribution system, and any resultant reliability improvement.
- Assists in understanding the intricacies of microgrid system operation, costs and their ability to address other value streams such as reliability, load shaping and power quality.
- Creates a quantified list of Company distribution system impacts resulting from the interconnection of microgrids.
- Enables the creation of policy and standards for subsequent microgrid interconnection requests, if and when allowed by the Company.
- Enables the potential development of a future microgrid service program.

Potential future applications for similar projects:

Collaborate with customers to identify and potentially deploy microgrid systems that utilizes advanced control systems and Internet of Things (IoT) for optimizing distributed energy resources.

STEP Project Report

Period Ending December 31, 2017

STEP Project Name:

Smart Inverter Project

Project Objective:

To investigate the capabilities of smart inverters and their impact and benefit for the company's electric distribution system.

Project Accounting:

	2017
Annual Collection (Budget)	N/A
Annual Spend (Capital)	N/A
Committed Funds	N/A
Uncommitted Funds	N/A
External OMAG Expenses	N/A
Subtotal	N/A

Project Milestones:

Milestones	Delivery Date	Status/Progress
Hosting Capacity Study of RMP Distribution Circuits	6/31/2018	Initiated; Circuit selection complete and data collection started
Laboratory Evaluation of Smart Inverters	09/30/2018	Initiated; Inverter selection and test plan development underway
Smart Inverter Setting Analysis	8/31/2018	Not Started
Review of Interconnection Requirements and Industry Practices	10/31/2018	Not Started

Key Challenges, Findings, Results and Lessons Learned:

Description of Investment	Anticipated Outcome	Challenges	Findings	Results	Lessons Learned
a.					

b.					
c.					

Program Benefits

- This program will enable a greater understanding of these innovative solutions as the Company continues to make the grid more progressive
- Provides the Company, Utah Public Service Commission, and other stakeholders with information regarding the capabilities of advanced inverters and changes to interconnection standards.
- The findings from this project will assist the company in updating *PacifiCorp Policy 138: Distributed energy resource interconnection policy.*
- Enables the company to gain knowledge on smart inverter operation for solar and battery combined projects.
- Enables the Company to become familiar with and utilize innovative technologies to provide customers with solutions to power quality issues.
- Opportunity to provide guidance to the company's distribution engineers to enhance the company's distribution planning process.
- The Company continues to experience rapid growth in interconnection requests and considers innovative technologies such as smart inverters a valuable tool to improve service to customers.
- Provides a better understanding of smart inverter settings will potentially assist in improved utilization of grid assets leading to cost savings for customers.
- This project aligns with the goals of the program to support the greater use of renewable energy. Through this project, the Company is taking steps to prepare for an enhanced deployment of clean energy sources for its customers.

Potential future applications for similar projects:

Develop automated hosting capacity analysis tool to leverage on smart inverter capabilities and provide enhanced grid support using DER systems connected to the distribution system.