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1. INTRODUCTION

Southwest Research Institute® (SwRI®), Schlumberger Technology Corporation (SLB), and Chevron Corporation® (Chevron) are working to jointly develop a novel, optimized, and lightweight modular process for natural gas (NG) to replace water as a low-cost fracturing medium with a low environmental impact. Hydraulic fracturing is used to increase oil and NG production by injecting high-pressure fluid, primarily water, into a rock formation, which fractures the rock and releases trapped oil and NG. This method was developed to increase yield and make feasible production areas that would not otherwise be viable for large-scale oil and NG extraction using traditional drilling technologies.

Since the fracturing fluid is composed of approximately 90% water, one of the principal drawbacks to hydraulic fracturing is its excessive water use and associated large environmental footprint. According to recent data, fracturing applications in North America can consume as much as 11 million gallons of water per well [1]. During the fracturing process, some of the fracturing fluid is permanently lost and the portion that is recovered is contaminated by both fracturing chemicals and dissolved solids from the formation. The recovered water or flow-back represents a significant environmental challenge, as it must be treated before it can be reintroduced into the natural water system. Although there is some recycling for future fracturing, the majority of the flow-back water is hauled from the well site to a treatment facility or to an injection well for permanent underground disposal.

To mitigate these issues, an optimized, lightweight and modular surface process using NG to replace a majority of the water is being developed as a cost-effective and environmentally clean fracturing fluid. Using NG will result in significantly less consumption since the gas that is injected as a fracturing fluid will be mixed with the formation gas and extracted as if it were from the formation itself. This process will minimize the collection, waste, and treatment of large amounts of water and reduces the environmental impact of transporting and storing the fracturing fluid.

There are two major steps involved in utilizing NG as the primary fracturing medium: (1) increasing the supply pressure of NG to wellhead pressures suitable for fracturing and (2) mixing the required chemicals and proppant needed for the fracturing process at these elevated pressures. The second step (NG-proppant mixing at elevated pressures) still requires technology advancements but has previously been demonstrated in the field with other gases such as nitrogen (N_2) and carbon dioxide (CO_2). However, the first step (a compact, on-site unit for generating high-pressure NG at costs feasible for fracturing) has not been developed and is currently not commercially available. Due to the inherent compressibility of NG, more energy is required to compress the gas than what is required to pump water (or other incompressible liquids) to the very high-pressure required for downhole injection. This project aims to develop a novel, hybrid method to overcome this challenge.

The project work is being performed in five sequential phases. The first phase included a thorough thermodynamic, economic, and environmental analysis of potential process concepts, as well as detailed design of three, top-performing processes. The work completed in the first phase allowed the selected thermodynamic pathway of direct compression to be optimized for the intended application. In the second phase, a pilot-scale facility was constructed at the SwRI facilities in San Antonio, TX. The pilot-scale facility was used to generate NG foam at elevated pressures similar to those found in a field application. The facility was used to investigate various properties of NG foam; such data are not available in the literature. In the third phase, the pilot-scale facility was used to further explore the feasibility of this novel technology and provided a more substantial data set that can be used to implement the technology in the field. In the fourth phase (the current phase), laboratory tests, process models, and pilot-scale tests will be expanded to investigate the effects of realistic fluids and operating conditions. Specifically, the effects of multi-constituent NG mixtures, water impurities, and elevated operating temperatures on foam stability will be investigated. Furthermore, the impact of NG mixtures on the compression process efficiency and equipment footprint will be investigated. In the fifth phase, the potential for NG foam to enhance oil and gas recovery will be investigated in a series of laboratory fracture network tests.

The first budget period (BP1) for this project was completed in December 2015. Work from this first effort demonstrated that the use of a direct-compression system for fracturing is commercially viable and has economic potential. Work for the second budget period (BP2) was completed on March 31, 2017, and included pilot-scale investigations that demonstrated that stable NG foam can be generated at elevated pressures. The third budget period (BP3) was completed on December 31, 2018, and included expanded pilot-scale tests to further investigate the fluid properties of NG foam using a range of base fluid mixtures. The fourth budget period (BP4), began on January 1, 2019. This report covers work completed in the first quarter of BP3. The project goals and accomplishments related to those goals are discussed. Details related to any products developed in the quarter are outlined. Information on the project participants and collaborative organizations is listed and the impact of the work done during this quarter is reviewed. Any issues related to the project are outlined and, lastly, the current budget is reviewed.

2. ACCOMPLISHMENTS

2.1 Project Goals

The primary objective of this project is to develop and test a novel approach to use readily available wellhead (produced) NG as the primary fracturing fluid. This includes development, validation, and demonstration of affordable non-water-based and non-CO_2-based stimulation technologies, which can be used instead of, or in conjunction with, water-based hydraulic fracturing fluids to reduce water usage and the volume of flow-back fluids. The process will use NG at wellhead supply conditions and produce a fluid at conditions suitable for injection.

The project work is split into five budget periods. The milestones for each budget period are outlined in Table 8. This table includes an update on the status of each milestone in relation to the initial project plan. Explanations for deviations from the initial project plan are included.

2.2 Accomplishments

In the past quarter, the contract modification to proceed with BP4 scope of work was received on January 9, 2019, along with an initial level of project funding. The remaining project funds for BP4 were authorized on March 15, 2019. During the quarter, the project team of SwRI, SLB, and Chevron met in person to kick-off the project work and to tour some of the Schlumberger laboratories that will be utilized for the BP4 and BP5 scopes of work. A kick-off presentation was given to key personnel at DOE NETL.

Technical work during this time focused on: identifying the effects of water quality on the stability of foams, identifying natural gas mixtures to use in laboratory analyses and system analyses, preparing the pilot-scale foam test facility for tests at elevated temperature conditions, and updating the compression cycle model with representative natural gas mixtures. These accomplishments are discussed in detail in the following sections.

2.2.1 BP4 Project Objectives

The primary objective in BP4 is to identify how fluid composition and reservoir operating conditions affect the stability of the natural gas-based foams. To achieve this objective, two test campaigns will be conducted. First, the existing pilot-scale foam test facility at SwRI will be operated at elevated temperatures that are relevant to reservoir conditions (e.g., approximately 250 to 300 °F). The purpose of this set of tests is to investigate whether the natural gas-based foams, that have previously been shown to be stable at low temperature, will remain stable in the elevated temperature condition. Foam visualization equipment will be used for these tests to characterize properties of the foam, such as bubble size distribution, foam texture, and half-life. The second set of tests will be conducted at Schlumberger's laboratories with an existing closed-loop foam rheometer to explore the impact of gas and water composition on the rheology and stability of natural gas foams.

A second objective of the BP4 work is to identify the effects of fluid composition (i.e., natural gas composition) on the efficiency and equipment layout of the direct compression process. Compression cycle models developed during BP1 will be updated to investigate the impact of multicomponent natural gas mixtures.

A final objective of the BP4 work is to explore whether the use of natural gas-based foams may result in some production benefits. For this work, existing software tools will be used to model production from a selected reservoir using rheology data generated during this project.

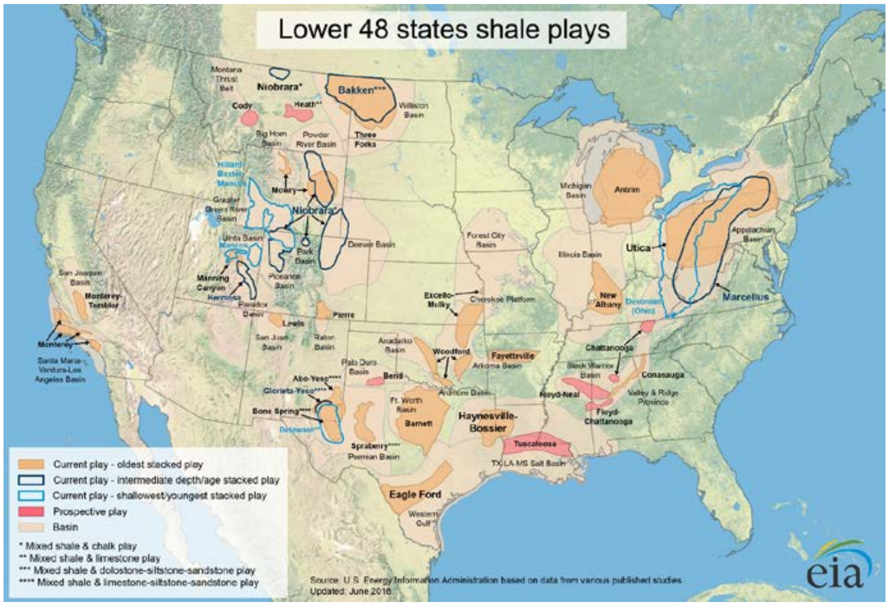
2.2.2 Temperature and Water Quality Effects on Foam Stability

One of the key objectives for the BP4 work is to identify the stability of natural gas-based foams when exposed to conditions that are relevant to the final field application, such as high-pressure and high-temperature operating conditions. In addition to reservoir operating conditions, the fluids used to create the natural gas foam are also relevant to the final field application. In particular, it is envisioned that produced water (as opposed to fresh water) could be used for the aqueous phase of the foam. As such, the effect of water quality on the foaming ability (i.e., the ability to mix the foam) and the foam stability over time must be identified. As an initial step, a literature review was conducted to identify any known effects of water quality and temperature on the stability of foams.

The available literature on foam used in oil and gas applications focuses almost entirely on air-based, N_2-based, and CO_2-based foams. However, this project has demonstrated that the qualitative trends applicable to N_2 and CO_2 foam are generally applicable to natural gas-based foam and are informative; particularly in designing the tests for BP4. Key observations and conclusions from the literature review are summarized in the following sections.

Relevant Reservoir Temperature and Temperature Effects on Foam Stability

The bottomhole pressure and temperature of several major shale plays were identified. Figure 1 maps the major shale plays in the 48 contiguous states and Table 1 provides the bottomhole temperature and pressure of the reservoir. Based on this information, it was determined that the maximum temperature target for the foam stability tests will be 300 °F.


Lower 48 states shale plays

Source: U.S. Energy Information Administration based on data from various published studies
Updated: June 2016

Figure 1. Shale Plays in Lower 48 States of United States [2] as of 2011.

Table 1. Range of Shale Depths, Bottomhole Temperature, and Reservoir Pressure of Plays in North America

Shale play	Basin	Depth [ft]	Bottomhole Temperature [°F]	Reservoir Pressure [psi]
Barnett [3–5]	Fort Worth	6,500 – 8,500	200	3,000 – 4,000
Woodford [4]	Andarko	6,000 – 11,000	130 – 170	5,000 – 10,000
Granite Wash [6]	Andarko	9,000 – 14,500	~200	4,000 – 10,000
Eagle Ford [7]	Maverick	4,000 – 14,000	175 – 300	4,000 – 8,000
Fayetteville [4]	Arkoma	1,500 – 6,000	100 – 150	1,000 – 2,000
Wolfcamp	Permian	4,000 – 10,000	100 - 160	2,000 – 5,000
Spraberry [8]	Permian	5,100 – 8,300	130 – 140	900 – 900
Haynesville [4]	Louisian	10,500 – 13,500	260 – 380	10,000 – 12,000
Marcellus [4,9]	Appalachian	4,000 – 8,500	100 – 150	1,500 – 5,000
Utica [10,11]	Applachian	4,000 – 8,000	140 – 250	4,500 – 9,000
Ohio [3,5]	Applachian	2,000 – 5,000	100 – 140	500 – 2,000
Antrim [3,5]	Michigan	600 – 2000	~75	200 – 700
New Albany [3,5]	Illinois	500 – 2,000	80 – 105	300 – 600
Niobrara [12]	Rocky Mt.	3,000 – 14,000	120 – 160	7,000 – 10,000
Bakken	Rocky Mt.	4,500 – 9,500	175 – 250	3,000 – 7,300
Lewis [3–5]	San Juan	3,000 – 6,000	130 – 170	1,000 – 1,5000
Mancos [13]	San Juan	2,700 – 7,000	150 – 170	570 – 1,900
Duvernay [14]	Alberta	9,000 – 12,000	170 – 230	4,300 – 6,100

Due to geothermal gradients, foam used in drilling and hydraulic fracturing processes undergoes a significant variation in the operating temperature with increasing wellbore depth. Moreover, the foam experiences a pH change from alkaline to acidic nature during foaming and defoaming process [15]. The physicochemical parameters such as temperature, surface tension, pH, ionic strength (function of salt concentration) etc. significantly influence the interfacial behavior of the foaming agents/stabilizers that control the rheological properties, foaming ability, and foam stability. Foaming ability is the ability of the surfactant to produce foam whereas the foam stability refers to the durability or lifetime (half-life) of the foam.

Several experimental investigations have focused on studying the effect of high temperatures, varying pH, and salt concentrations on the foaming ability and stability of the aqueous foams. Some of the experimental investigations dedicated to the study of aqueous foams at elevated temperatures are summarized in Table 2.

Table 2. Summary of Experimental Literature on the Effects of Temperature on the Stability of Aqueous Foams

Source	**Foam formulation**			**Press.**	**Temp.**
	Liquid phase	**Additives / Surfactants**	**Gas**	[psi]	[°F]
[16]	Brine (Na^+, Ca^{2+}, Cl^- based)	Non-ionic: NP-7, NP-10, NP-15, NP-21, Alkyl polyglycoside Anionic: SDS, SDS’, SDBS	CO_2	725	140 - 248
[17]	Distilled water	Surfactant (foamer)	N_2	Atm	73 - 194
[18]	Brine (1% by wt. KCl)	Anionic: SDS Cationic: Cetyltrimethyl ammonium bromide Polymer: Hydroxy Ethyl Cellulose (HEC)	Air	Atm	86 - 122
[19]	Distilled water	Cationic: Zonyl FSD flurosurfactant Non-ionic: Zonyl FSN flurosurfactant Anionic: Zonyl FS-62 flurosurfactant	N_2	Atm	68 - 176
[20]	Salt water	Anionic: C12/C3 alkyl phosphate ester	Air/N_2	100	77 - 194
[21]	Water	Anionic: AOS, SDBS, Sodium lauryl sulfate (K12), Sodium lauroyl sarcosinate (LS-30) Cationic: Cetyl trimethyl ammonium chloride (1631), dodecyl trimethyl ammonium chloride (1231) Amphoteric: disodium cocoamphodiacetate (CAD-40), Lauramido propyl hydroxyl sultaine (LHSB)	Air	NA	60 - 150
[22]	Water	Non-ionic: N-NP-15c, N-NP-21c Ionic: N-NP-15c-H, N-NP-21c-H	CO_2	750 – 1,700	100 - 210
[23]	Brine (22.0×10^4 mg/L in total salinity) + crude oil	Amphoteric: Cocamidopropyl Hydroxysultaine	N_2		176 - 250
[24]	Brine (Ca^{2+}, Mg^{2+} based 22.0×10^4 mg/L in total salinity) + crude oil	Non-ionic: Polyoxy Ethylene Nonyl Phenyl Ether, Cocoalkylamine, Alkylphenol Ethoxylates, Alkyl Polyglycosides Amphoteric: Hydroxy Sulfobetaine, Imidazoline, Dodecyl Dimethyl Betaine, Lauryl Hydroxysultaine, Cocoamidopropyl Betaine, Aliphatic Alcohol Polyoxyethylene Ethers Sulfonates, Lauramidopropyl Betaine Anionic: SDS, A-olefin Sulfonate, Diphenyloxide Disulfonate	N_2	3000	176 - 250

AOS = Sodium alpha-olefin sulfonate, SDS: Sodium Dodecyl Sulfate, SDS’ = Sodium dodecyl sulfonate, SDBS = Sodium dodecyl benzene sulfonate

Foaming temperature is a critical factor that influences the foaming ability of the surfactant and stability of the foams. As shown in Table 1, bottomhole temperatures greater than 200 °F are not uncommon in the North American shale plays. Thus, it is desirable to have a foam that can survive elevated temperatures without degradation. Parameters such as Brownian motion, foam viscosity, critical micelle concentration, gas-liquid interface surface tension etc. decide the foaming ability and foam stability. Literature shows that these parameters are affected by the change in temperature and degrade the foam's stability at elevated temperatures [16–25]. The work of Y. Zhang et al. [22] with CO_2 based aqueous foams show that as the temperature is raised from 100 °F to 210 °F, the foam liquid film evaporates and the viscosity decreases. This leads to an accelerated liquid drainage from the foam lamellae that aggravates the bursting process of the foam and hence degrades the foam half-life. Their study showed that in comparison to non-ionic surfactants, ionic surfactants can better tackle temperature effects on the foam stability. A recent study by Wang et al. [16] with CO_2 based aqueous foams at 725 psi shows that in the presence of non-ionic surfactants, the foaming ability and foam half-life experience a 4x reduction when the foam temperature is changed from 140 °F to 248 °F. Nevertheless, use of certain foaming agents such as anionic surfactants have potential to retard the effect of temperature on the foam stability.

Similarly, experimental work of [18, 24, 25] with N_2 based aqueous foams shows degradation of foaming foam stability (half-life) with increase in the foam temperature. Whereas, the foaming ability of surfactant is found to increase with increase in the temperature. This tendency is due to increase in the kinetic energy of the surfactant molecules that enhances the adsorption rate of surfactants at the gas-liquid interface and hence improves the foaming ability. A comparative study of CO_2 and N_2 based aqueous foams [26] over a wide range of pressure and temperatures concluded that increase in temperature improves liquid lamellae's monolayer permeability and increases the pressure inside gas bubbles. The monolayer permeability favors mass diffusion and the pressure difference leads to merger of smaller bubbles with larger gas bubbles resulting into unstable foam behavior. Effect of temperature on the stability of N_2 and CO_2 based foams is illustrated in Figure 2.

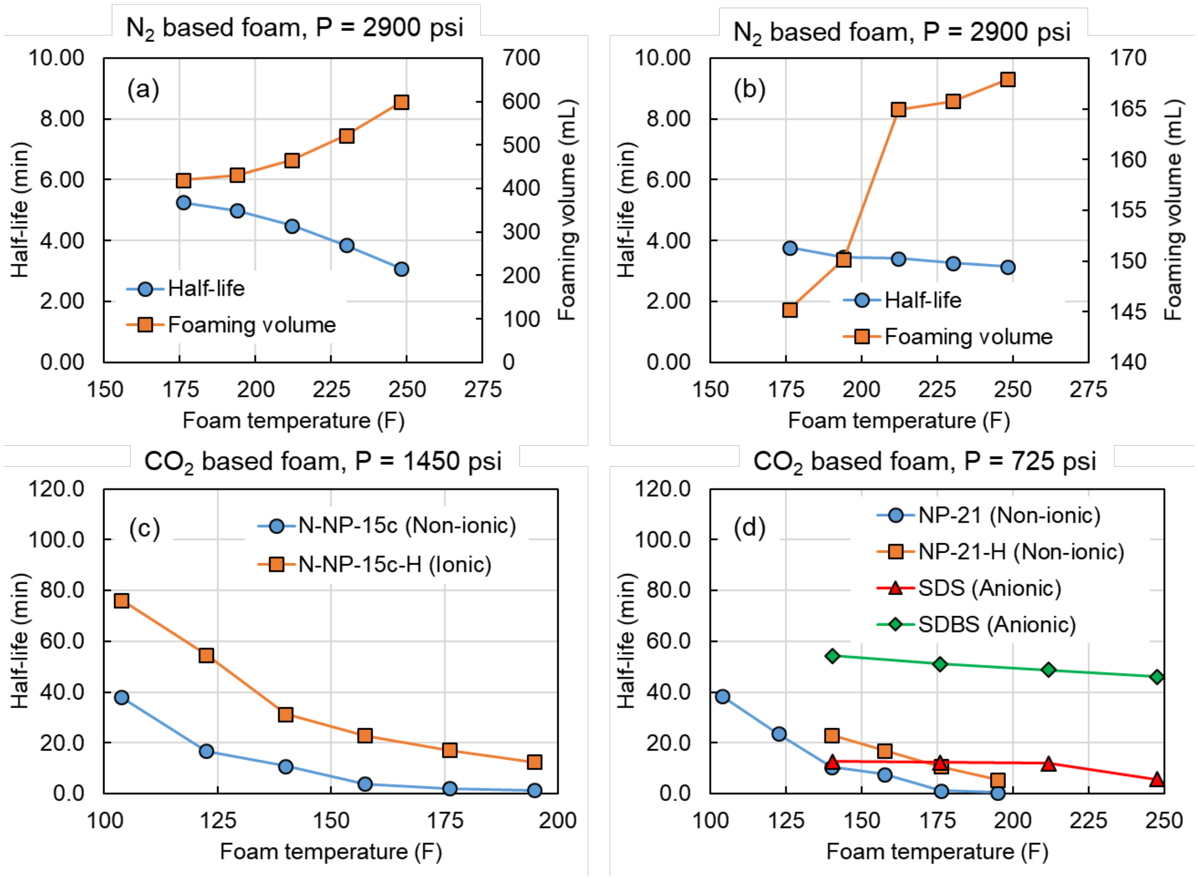


Figure 2. Effect of temperature on foam stability (half-life). (a) N2 based foam using amphoteric surfactant [23], (b) N2 based foam using non-ionic and anionic surfactants [24] (c) CO2 based foam using non-ionic and ionic surfactants [22], (d) CO2 based foam using non-ionic and anionic surfactants [16].

Effect of Aqueous phase pH on Foam Stability

The change in pH of the foam's liquid (aqueous) phase essentially alters the surface charge and zeta potential of the foaming agents. This change in surface properties affects the molecular interaction (cohesion/repulsion) between the foaming agent's molecules that further influence the interfacial properties of the liquid film and hence the foam stability. Aqueous foam literature reports the effect of pH on the stability of N_2 [17] and CO_2 [27] based foams. For N_2 based foams [17], the effect of pH in a range of 2-12 on the stability and foaming ability of aqueous foam is shown in Figure 3. The foam stability (expressed as instantaneous foam volume) was found to increase for $2 > pH > 9$. Further increase in aqueous phase pH resulted in decreased foam stability. Their study showed the foaming ability is less sensitive to the pH in acid range. Whereas, in the base range, the foaming ability is decreased dramatically at $pH \geq 12$. Similarly, for CO_2 based foams [27], a non-linear effect of increase in pH on the decrease in initial foam volume was reported. Although, the percentage decrease in foam volume was small (less than 5%) at all pH values, the foam stability was highest at pH ~ 5 and lowest at pH ~13. They argued that the injection of CO_2 in the aqueous phase creates a buffering effect and hence diminishes the effect of increasing pH on the foam stability.

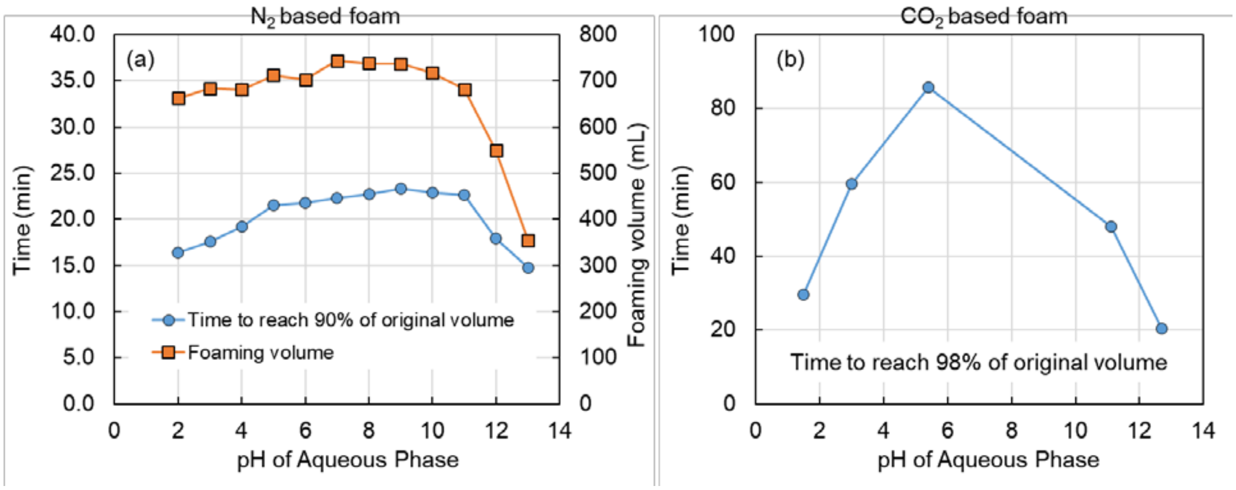


Figure 3 Effect of pH on foam stability: (a) N_2 based foam [17], (b) CO_2 based foams [27].

Effect of pH on the foam stability and foaming ability is non-linear.

Effect of Aqueous phase Salinity on Foam Stability

Similar to the effect of pH, the change in salt concentration in the aqueous phase of the foam affects the particle charge and hence the zeta potential of the foaming agent. The change in zeta potential affects the foaming agent's adsorption rates at the gas-liquid interface and eventually controls the foam stability. A recent study with N_2 based foams [23] revealed that a fourfold increase in aqueous phase salinity marginally decreased the foaming ability but increased the foam half-life by more than 30%. They argued that increase in increased salt concentration resulted into adsorption of salts at gas-liquid interface. This resulted in thicker lamellae making it difficult for the aqueous phase to drain and destabilize the foam. Another studies on N_2 based foam [17, 28] and air-based foam [29] exhibited a trend of decreasing foam stability with increase in the salt concentrations. A similar trend in terms of decreasing foam viscosity with increase in salt concentration was observed [30]. They concluded that increase in salt concentration tends to compress the electric double layer of the surfactant at the gas-liquid interface that results in aggregation and precipitation of the foaming agents leading to decrease in the bubble surface tension and foam viscosity. A foam with reduced viscosity undergo a quicker liquid drainage that reduces the foam half-life. It must be mentioned that the work of Sun et al. (2016) [23] used zwitterionic surfactant (surfactants with both anionic and cationic behavior) others used anionic surfactants [17, 28–30]. Rojas et al. [28] found a 15x reduction in half-life when the salt concentration was increased from 0.5% (by wt.) to 1%. However, as shown in Table 3, the adverse effect of added salinity on the foam half-life was largely impeded after the addition of non-ionic polymer to the aqueous foam. The polymer acted as a stabilizing agent and opposed the detrimental effect of salt concentration on the foam's half-life. Thus, it appears that the stability of aqueous foams with variation in the aqueous phase salinity is dependent on the type of foaming agent (surfactant) and presence of stabilizers.

Table 3. Effect of Salt Concentration and Presence Of Polymer on the Stability of Foams [28]

System	**Concentration (%)**	**Half-life (min)**
Anionic surfactant / Salt	0.5 / 0.5	63
Anionic surfactant / Salt	0.5 / 1.0	4
Anionic surfactant / Non-ionic polymer / Salt	0.5 / 0.2 / 0.5	349
Anionic surfactant / Non-ionic polymer / Salt	0.5 / 0.5 / 1.0	322

<u>Effect of Aqueous phase contamination with crude oil on Foam Stability</u>

In addition to the pH level and salinity of the aqueous phase, the contamination of the aqueous foam with crude oil also affects the foam's stability. The experimental studies of [17, 24, 30] show that the foam's stability at various concentrations of crude oil is dictated by the physical properties of crude oil such as density and viscosity. Mohammad et al. [17] found that low API crude oil i.e., oil with high density and high viscosity offered better foam stability. This is possibly because higher density oil easily forms an emulsion with water phase and increases the foam viscosity [30]. Increased viscosity slows down gravity driven drainage and thus prevents degradation of foam's half-life.

2.2.3 Pilot-Scale Foam Test Facility Updates

The pilot-scale test facility will be modified during BP4 with some key updates including an improved flow control mechanism in the tube rheometer section and some modifications to the foam collection system. To improve the flow and pressure control in the tube rheometer section, an additional control valve will be added where a manually controlled needle valve (VLV025) is currently installed (see Figure 4). In the current configuration, VLV025 is set to a fixed position (i.e., a fixed flow resistance) such that a majority of the flow bypasses the tube rheometer. Flow through the rheometer is increased by closing CV002. The primary issue with the current configuration is that as the control valve is closed, the overall system resistance increases and the upstream operating pressure increases. To alleviate this issue, a second control valve (CV004) will be added to this portion of the pilot-scale test facility. With the second control valve, the resistance downstream of the tube rheometer will become a variable resistance and the flows can be balanced between the two paths without increasing the upstream pressure. The valve selected for this application is identical to CV002, has been purchased, and is expected to arrive early in the next quarter.

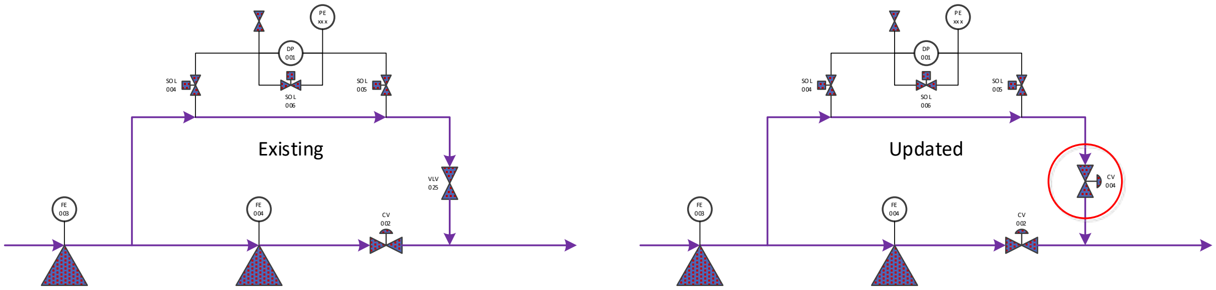


Figure 4. Existing (Left) and Modified (Right) Control and Instrumentation for Tube Rheometer Section

2.2.4 Compression Cycle Model Updates

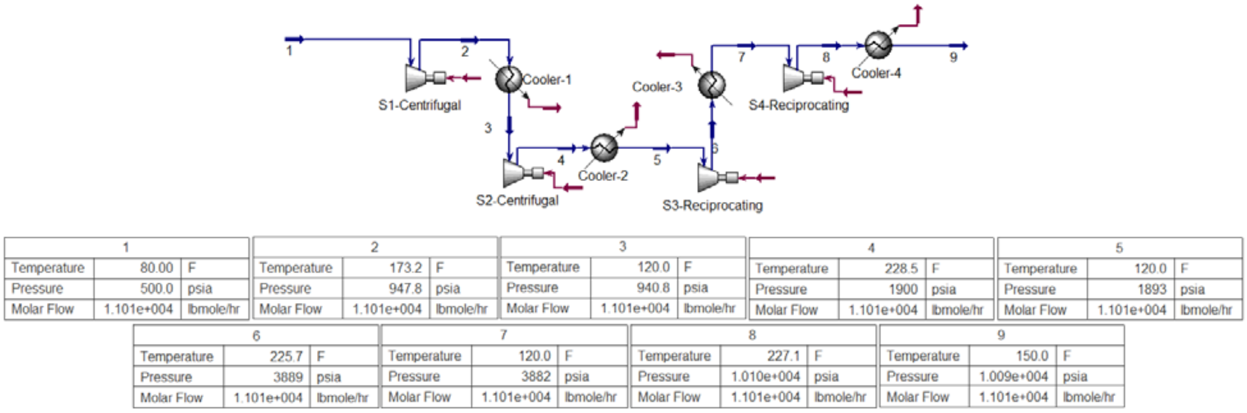
Based on previous phases of this project, the top cycle that was chosen for future work was direct compression. In the past quarter, efforts were made to update the thermodynamic cycle model for the direct compression cycle with representative natural gas mixtures to investigate the effects of using the available natural gas at possible field sites. Previously, methane was used in the thermodynamic models to generate a baseline for comparison to other cycles. In addition, the thermodynamics of pure methane are very well understood in comparison to more complex hydrocarbon mixtures found in the field.

Chevron provided background on energized fracturing history that included representative hydrocarbon mixtures that could be available for use during hydraulic fracturing. Two gas compositions provided by Chevron that were used in the thermodynamic cycle model are provided in Table 4.

Table 4. Representative Natural Gas Composition for Cycle Model Performance (Provided by Chevron)

Component	Chevron Comp 1	Chevron Comp 2
	%mol	%mol
Nitrogen	1.818	1.082
Carbon Dioxide	0.858	0.565
Methane	70.088	79.297
Ethane	16.035	13.428
Propane	7.757	4.025
iso-Butane	0.714	0.366
n-Butane	1.782	0.65
iso-Pentane	0.294	0.117
n-Pentane	0.325	0.136
Hexanes	0.158	0.128
Heptanes	0.114	0.119
Octanes	0.043	0.067
Nonanes	0.011	0.019
Decanes	0.003	0
Undecanes	0	0.001

The HYSYS process model of the direct compression cycle was used during this quarter with the most recently updated compressor and cooler specifications and conditions. The cycle layout diagram with the set pressures and temperatures is shown in Figure 5. The composition of the inlet stream (1) was changed to one of the representative gas composition shown in Table 4.



1		
Temperature	80.00	F
Pressure	500.0	psia
Molar Flow	1.101e+004	lbmole/hr

2		
Temperature	173.2	F
Pressure	947.8	psia
Molar Flow	1.101e+004	lbmole/hr

3		
Temperature	120.0	F
Pressure	940.8	psia
Molar Flow	1.101e+004	lbmole/hr

4		
Temperature	228.5	F
Pressure	1900	psia
Molar Flow	1.101e+004	lbmole/hr

5		
Temperature	120.0	F
Pressure	1893	psia
Molar Flow	1.101e+004	lbmole/hr

6		
Temperature	225.7	F
Pressure	3889	psia
Molar Flow	1.101e+004	lbmole/hr

7		
Temperature	120.0	F
Pressure	3882	psia
Molar Flow	1.101e+004	lbmole/hr

8		
Temperature	227.1	F
Pressure	1.010e+004	psia
Molar Flow	1.101e+004	lbmole/hr

9		
Temperature	150.0	F
Pressure	1.009e+004	psia
Molar Flow	1.101e+004	lbmole/hr

Figure 5. Direct Compression Cycle Layout Diagram with Operating Conditions

A parametric study was conducted using different equations of state (EOS) available in HYSYS. The purpose of this study was to determine the sensitivity of the cycle model to fluid property variations that result when different EOS are employed. Note that initial cycle models assumed pure methane as the working fluid and utilized the Aspen Properties package RefProp, based on the NIST REPFOP reference database.

The fluid property packages used in the study were RefProp (if available), Peng-Robinson, PR-Twu, SRK-Twu, and PSRK. Peng-Robinson and SRK are commonly used in evaluating hydrocarbon cycles. The pressures, temperatures and mass flowrates remained the same during the parametric study throughout the system. Results of the steady for the inlet stream (1) are provided in Table 5 and Table 6 for Chevron Comp 1 and Chevron Comp 2 gas compositions, respectively.

Table 5. Cycle Model Results for Inlet Condition (1) using Gas Composition Chevron Comp 1

Fluid Package	RefProp	SRK-Twu	Peng-Robinson	PR-Twu
Vapor / Phase Fraction	0.99690	0.99693	0.99731	0.99737
Vapor Mass Flow [kg/s]	27.7703	27.7643	27.7958	27.7981
Liquid Mass Flow [kg/s]	0.2297	0.2357	0.2042	0.2019
Std Ideal Liq Vol Flow [barrel/day]	42446	42200	42446	42200
Heat Flow [kW]	-102848	-103338	-102920	-103392
Compressor Power [kW]	11582	12245	TBD	11419
Heat Rejection [kW]	14103	15159	TBD	14596

Table 6. Cycle Model Results for Inlet Condition (1) using Gas Composition Chevron Comp 2

Fluid Package	Peng-Robinson	SRK-Twu	PSRK	PR-Twu
Vapor / Phase Fraction	0.99914	0.99895	0.99894	0.99913
Vapor Mass Flow [kg/s]	27.9086	27.8864	27.8861	27.9054
Liquid Mass Flow [kg/s]	0.0914	0.1136	0.1139	0.0946
Std Ideal Liq Vol Flow [barrel/day]	45246	45085	45147	45004
Heat Flow [kW]	-110924	-111439	-110605	-111278
Compressor Power [kW]	13075	14250	14156	13348
Heat Rejection [kW]	15834	17005	16726	16412

Note that some non-trivial differences in total heat flow and liquid volume flows result when the different EOS are used. More investigation will be performed in the next quarter to determine the best fluid property package to use with subsequent cycle analyses.

The initial finding when using the representative natural gas mixtures is that the initial condition at the inlet of the first compressor is multiphase. When using pure methane, the inlet stream to the first compressor is in the vapor state at the given operating conditions of 500 psia and 80 °F. When set to the same operating conditions, the two repetitive gas compositions investigated are in the two-phase region, meaning that liquid drop-out is predicted to occur at the first compressor. In the next quarter, we will investigate solutions to avoid multiphase compression.

The next steps for the next quarter involve updating the cycle model with at least two additional representative natural gas compositions. Example compositions will most likely include those from the Permian and Marcellus shale plays. Focus will be made on adding a composition that includes larger amounts of heavier hydrocarbons such as the composition found in Table 7 and possible a composition that is a lighter natural gas (80%mol+ methane). Due to the likelihood that the natural gas feed for the cycle will be multiphase under current conditions, an effort will be made to update the cycle model with characteristic compressor maps and parameters. This will allow a full examination of the effects of changing the inlet conditions of the compressors and their impact on the entire cycle performance.

Table 7. Example Natural Gas Composition at Permian Shale Basin [31]

Component	Site A, Permian Basin
	%vol
Methane	66.26
Ethane	13.66
Propane	10.29
Carbon Dioxide	0.34
n-Butane	3.76
Nitrogen	2.23
i-Butane	0.98
n-Pentane	0.87
Hexane	0.75
i-Pentane	0.83

2.2.5 Reservoir Model Updates

Figure 6 depicts the simulation workflow for modeling unconventional reservoirs. The workflow was derived from the integrated “seismic-to-simulation” workflow. These workflows have been designed around the use of a complex fracture model to seamlessly integrate the various processes involved in well completion design/analysis and production optimization for unconventional reservoirs. The key steps include the construction of the geological model and detailed mechanical earth model (MEM) with the geomechanical and reservoir properties, a detailed completion description, simulation of fracturing treatment (with natural gas foam in this instance), calibration of the fracture model against microseismic observation, generation of the reservoir grid model, and production simulation. Recent publication by Pankaj et al. [32] presented and used this complete workflow or some of its components in detailed reservoir characterization, completion design based on reservoir and completion quality, fracture simulation, calibration against microseismic data, and production matching and simulation.

In this study, we leverage the workflow steps as needed and use only components 1, 2, and 3 from Figure 6. In step 1, a geological model with geomechanical and petrophysical property distribution will be used from a reference well in the Eagle Ford formation.

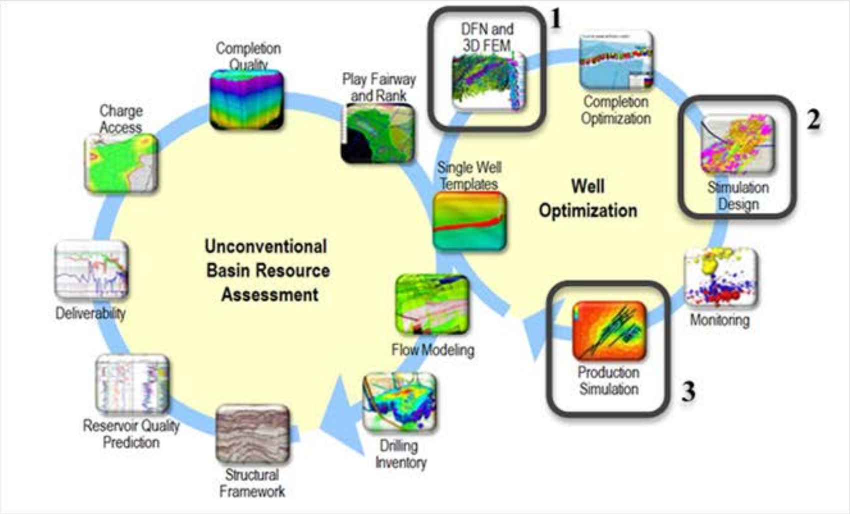


Figure 6. Single or multiple well pad completion optimization workflow

For the next step of stimulation design and hydraulic fracture modeling, a complex fracture model will be used. The complex model allows us to model the fracture geometry by predicting the interaction of hydraulic fractures with the pre-existing heterogeneity (rock fabric, texture, planes of weakness, or natural fractures) in the formation. The proposed fracture model simulates fracture propagation, rock deformation, stress shadow, and fluid and proppant flow in the complex fracture network. This model solves the problem of fluid flow in the fracture network and the elastic deformation of the fractures, and has similar assumptions and governing equations to those of conventional pseudo-3D fracture models. However, instead of solving the problem for a single planar fracture, the complex fracture model solves these equations for the complex fracture network, which is defined as the branching of the hydraulic fractures at the intersections with the natural fractures.

2.3 Opportunities for Training and Professional Development

No opportunities for training and professional development occurred during this last quarter.

2.4 Dissemination of Results to Communities of Interest

No publications or presentations were released in the past quarter.

2.5 Plan for Next Quarter

In the next quarter, the BP4 work will continue and will focus on generating a test matrix and schedule for the various laboratory tests along with continuing the modeling activities.

2.6 Summary of Tasks for Next Quarter

- Continue the design installation of pilot-scale facility upgrades to operate with natural gas foam at an elevated temperature
- Finalize the test matrix
- Continue modeling activities using natural gas mixtures

3. PRODUCTS

With any technical work, results will be documented and reported to the appropriate entities. In addition, the work may produce new technology or intellectual property. This section provides a summary of how the technical results of this project have been disseminated and lists any new technology or intellectual property that has been produced.

3.1 Publications

No publications were submitted during the past quarter.

3.2 Technologies or Techniques

No new techniques or technologies have been developed in the last quarter.

3.3 Intellectual Property

No intellectual property, such as patents or inventions, has been submitted or developed in the last quarter.

4. PARTICIPANTS & OTHER COLLABORATING ORGANIZATIONS

The work required to develop the high-pressure NG processing system for fracturing requires the technical knowledge and effort of many individuals. SwRI, SLB, and Chevron are collaborating to complete the work. This section provides a summary of the specific individuals and organizations who have contributed in the last quarter.

4.1 SwRI – Prime Contractor

The following list provides the name of the Principal Investigator (PI) and each person who has worked at least one person-month per year (160 hours of effort) in the last quarter.

- Griffin Beck
    - Project role: PI
    - Nearest person-month worked: 0.0
    - Contribution to project: BP4 test design and project management
    - Funding support: DOE
    - Collaborated with individual(s) in foreign country(ies): No
    - Country(ies) of foreign collaborator(s): None
    - Traveled to a foreign country(ies): No
    - If traveled to a foreign country(ies), duration of stay: N/A

4.2 Other Organizations

For this project, SwRI is collaborating with SLB and Chevron. SLB is a subcontractor and cost-share supporter for this project. Chevron is a cost-share supporter for this project. More information about their participation is listed below.

- SLB
    - Location of organization: United States
    - Partner’s contribution to the project: Analysis and design support, laboratory testing, reservoir modeling
    - Financial support: N/A
    - In-kind support: Labor hours in the first budget period
    - Facilities: N/A
    - Collaborative research: SLB staff supported reservoir modeling tasks during the first quarter
    - Personnel exchanges: N/A
- Chevron
    - Location of organization: United States
    - Partner’s contribution to the project: Analysis and design support
    - Financial support: N/A
    - In-kind support: Labor hours in the first budget period
    - Facilities: N/A
    - Collaborative research: Chevron staff provided technical expertise for the project
    - Personnel exchanges: N/A

5. IMPACT

The use of NG foam is expected to have a smaller environmental footprint and may enhance gas and oil recovery compared to traditional, water-based fluids. Despite these potential benefits, fracturing with NG foams has not been widely adopted due in part to limited fluid property data. This project has provided much-needed information to the industry to advance fracturing with NG foams.

As noted in previous reports, past research efforts by others have investigated the rheological properties of foams generated with nonflammable gases, namely nitrogen and carbon dioxide. However, published literature is not available for the rheological properties of NG foam. The data generated by this project will be critical in future design work, particularly in understanding the impact of the gas compression machinery.

6. CHANGES/PROBLEMS

In the past quarter, updated milestones and delivery dates were generated for the additional project phases. These changes are documented in Table 8 beginning with Milestone H.

Table 8. Summary of Milestone Completion Status

Budget Period	Milestone Letter	Milestone Title/Description	Planned Completion Date	Actual Completion Date	Verification Method	Comments (Progress towards achieving milestone, explanation of deviations from plan, etc.)
1	A	Top 2 to 3 Thermodynamic Cycles Identified	January 2, 2015 **New: June 9, 2015**	Complete June 9, 2015	At least two combinations of thermodynamic paths and sets of equipment have been identified as being capable of accomplishing natural gas compression from approximately 200-1,000 psi inlet to 10,000 psi outlet.	Completion of this milestone has been delayed by execution of full contract. Actual completion date was June 9, 2015.
	B	Top Thermodynamic Cycle Identified	May 1, 2015 **New: September 30, 2015**	Complete September 30, 2015	At least one combination of thermodynamic paths and sets of equipment has been identified as being capable of accomplishing natural gas compression from approximately 200-1,000 psi inlet to 10,000 psi outlet in an economically feasible fashion. This is considered a critical path milestone.	Start of this work was delayed due to delay in execution of full contract. Actual completion date was September 30, 2015.
	C	Finalized Detailed Design	September 30, 2015 **New: December 31, 2015**	Complete, December 31, 2015	A laboratory-scale compression/pump test train will be designed to accomplish natural gas compression from approximately 200-1000 psi inlet to 10,000 psi outlet in an economically feasible fashion. This is considered a critical path milestone.	With the delay in execution of the full contract, this milestone was completed on December 31, 2015.
2	D	Compressor/Pump Train Set-up Complete	March 17, 2016 **New: December 30, 2016**	Complete, December 30, 2016	The laboratory-scale compression/pump test train will be assembled/constructed. This is considered a critical path milestone.	Due to a delay in contract execution, delays with component deliveries, and delays related to commissioning, the construction was completed Dec. 30, 2016.
	E	Test Data Acquired and Analyzed	September 30, 2016 **New: March 31, 2017**	Complete, March 31, 2017	Measured data will confirm that the laboratory-scale compression/pump test train is able to accomplish natural gas compression from approximately 200-1000 psi inlet to 10,000 psi outlet in an economically feasible, compact, and portable fashion. This is considered a critical path milestone.	With the delayed completion of the test stand, testing and data analysis was completed March 31, 2017.
3	F	Test Facility Modifications Complete	October 31, 2017 **New: March 31, 2018**	Complete March 30, 2018	Modifications to the BP2 test stand are complete and the test matrix has been generated.	The test stand modifications were completed on March 30, 2018.
	G	Test Data Acquired and Analyzed	3/31/2018 **New: December 31, 2018**	Complete December 31, 2018	Measured data will provide detailed information about the rheology properties of NG foam.	Initial data processing is complete. Further processing will occur as needed.
4	H	Test Facility Modifications Complete	August 13, 2019	In Progress	Modifications to support high-temperature stability tests are complete	Facility upgrades are being designed
	I	Test Data Acquired and Analyzed	December 31, 2019		Data collected on the pilot-scale foam test facility and the closed-loop rheometer will be used to determine the effect of water quality, gas composition, and operating temperature on the stability of natural gas-based foam	
	J	Compression Cycle Models Updated	September 30, 2019	In Progress	Cycles have been modeled with realistic natural gas compositions	Model updates are in progress
	K	Initial Reservoir Model Complete	September 30, 2019	In Progress	Initial reservoir models will be used to explore potential production benefits related to natural gas-based foam	Reservoir model parameters are currently being explored/defined
5	L	Portable Foam System Complete	June 30, 2020		The portable foam system has been designed, built, and commissioned	
	M	Test Data Acquired and Analyzed	December 31, 2020		Fracture network data has been generated and analyzed	
	N	Final Reservoir Model Complete	September 30, 2019		The reservoir model has been updated with additional information generated by the fracture network tests	

7. BUDGETARY INFORMATION

A summary of the budgetary data for the BP4 portion of the project is provided in Table 9. This table shows the planned costs over the four quarters, the actual incurred costs to date, and the variance for the current budget period. The costs are split between the Federal and Non-Federal share.

In the first quarter of BP4, $25,085 were used in support of the project kick-off meeting, the literature review, and the initial modeling efforts described previously. The variance between the planned costs and the actual costs are due to in part to a delay in some of the test loop modification activities. It is expected that the current variance will be corrected as loop modification activities increase and as invoices are received from SLB and Chevron.

Table 9. Budgetary Information for Budget Period 4

Budget Period 4				
Reporting Quarter	**Q1**	**Q2**	**Q3**	**Q4**
Start	**1/5/2019**	**3/30/2019**	**7/6/2019**	**9/28/2019**
End	**3/29/2019**	**7/5/2019**	**9/27/2019**	**1/3/2020**
Baseline Cost Plan	$148,932	$406,734	$658,888	$804,755
Federal Share	$106,721	$322,311	$532,253	$635,909
Non-Federal Share	$42,211	$84,423	$126,634	$168,846
Total Planned	***$148,932***	***$406,734***	***$658,888***	***$804,755***
Actual Incurred Cost	$25,085			
Federal Share	$25,085			
Non-Federal Share	$0			
Total Incurred Costs	***$25,085***			
Variance	$123,847			
Federal Share	$81,636			
Non-Federal Share	$42,211			
Total Variance	***$123,847***			

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