REDACTED

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

October 16, 2020

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-3398

Attn: Filing Center

Re: UM 1857—PacifiCorp's Third Compliance Filing – Energy Storage Pilot and Evaluation Plan Update

PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company) submits for filing in compliance with Public Utility Commission of Oregon (Commission) Order No. 18-327, and modified by Order Nos. 19-242 and 19-333, updated estimated benefits and costs associated with the Company's energy storage pilot programs.

Pilot Project 1—Energy Storage Solution

On April 2, 2018, PacifiCorp selected for Commission approval in this docket the two megawatt/six megawatt-hour (MWh) base case energy storage solution as the preliminary sizing for the proposal, as described in Section 4.0 of the Final Oregon Energy Storage Project Proposal document (Pilot Project 1). This sizing met the minimum threshold of five MWh as set forth by House Bill 2193, accommodates the historic outage characterization on the feeder, and presented the lowest risk option given the information available to PacifiCorp at the time. PacifiCorp now provides an additional update on the current status of this project.

The Company originally planned to construct this project on land near the Hillview Substation in Corvallis, Oregon. After an exhaustive search of available property with willing property owners, it was determined that the only viable land would result in the removal of at least one residence and displacement of the occupant. Following consultation with Commission staff, PacifiCorp restarted the search for available property looking at other locations both in Corvallis and across PacifiCorp's Oregon service territory. One location that is fed from the Lakeport Substation located in Klamath Falls, was identified as a good candidate that allows for all of the high level use cases. The Company is currently engaged in negotiations for the use of a portion of a vacant parcel of land on which the Company intends to acquire a termed exclusive easement. At the time of this report, this property appears to be very favorable for the project and the Company expects to have a land agreement in place by the end of 2020.

The Owner's engineering is being provided by an external engineering firm and was procured through competitive bid and awarded at the end of 2018. The Owner's Engineer was selected based on lowest bid. The winning bid was for $[redacted]. This cost is in addition to the internal engineering reviews and project management. The combined costs were originally estimated to be approximately $60,000; however, based on current estimates and awarded contracts, this portion of the project is now estimated to be $255,000. The Owner's Engineers have completed the conceptual design, interconnection application, and permitting review.

The engineering, procurement, and construction (EPC) request for proposals issued in 2019 did not receive any qualified bid responses. As a result the EPC contract has been split into three contracts. The Engineering contract was awarded in December of 2019 for $[redacted], which was in line with the updated total project estimates. The equipment vendor has been selected and the agreement is expected to be executed by the end of 2020 for approximately $[redacted]. The Construction contract will be competitively bid in spring of 2022 once design is complete and the generation interconnection approval is granted.

This project is subject to the generation interconnection process. This review and acceptance process requires the project apply for a position in the interconnection queue once property rights have been obtained. The Company plans to submit this project for generation interconnection review by the end of 2020 to be placed in the spring 2021 queue. This will allow for project approval and construction to start in fall 2021 and commercial operation in spring 2022.

Finally, the cost of interconnecting the battery system to the distribution system was originally estimated at $550,000, but is now estimated at $805,000 based on the current design. [redacted].[1]

Pilot Project 2—Community Resiliency Pilot

In the stipulation filed in docket UM 1857 by PacifiCorp on July 18, 2018, and adopted by the Commission in Order No. 18-327 (September 4, 2018), PacifiCorp committed to developing a Community Resiliency Pilot (Pilot Project 2) to provide technical and financial assistance to study and deploy energy storage resources to facilities critical to emergency response or disaster recovery. The stipulation laid out a phased approach for Pilot Project 2, beginning with a consultant-led technical assistance concept resulting in a limited number of initial studies (Phase 1), followed by financial assistance for the installation of energy storage resources for up to four critical facilities (Phase 2).

In Order No. 18-327, the Commission authorized PacifiCorp to recover up to $200,000 in Phase 1 of Pilot Project 2. After the completion of Phase 1, but prior to beginning Phase 2, PacifiCorp will file a revised plan estimating the costs, benefits and anticipated learnings associated with

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[1] PacifiCorp's 2019 IRP is available online at the following link: https://www.pacificorp.com/energy/integrated-resource-plan.html.

Pilot Project 2 for Commission approval and seek Commission authorization to recover costs associated with Phase 2.

After a competitive procurement process, PacifiCorp awarded the technical assistance contract for Pilot Project 2 to TRC in August 2019. In November 2019, PacifiCorp initiated outreach to critical facilities across the state, culminating in the preliminary identification of nine facilities, which representatives expressed interest in participating in Pilot Project 2. PacifiCorp began the formal site selection and technical assessment process in early 2020, however, the coronavirus and associated response efforts soon caused disruptions in the implementation of Pilot Project 2.[2]

To date, PacifiCorp has completed and delivered three studies to customers. Another site progressed through the final desktop review stage before PacifiCorp lost engagement.[3] Two additional sites were selected for participation in the program and had proceeded to different stages of the technical assessment process before PacifiCorp lost engagement. PacifiCorp continues to look for opportunities to reengage facility managers and complete those studies.

PacifiCorp is nearing completion of a final report which details key learnings from Phase 1 of Pilot Project 2, based on the technical assessment work it was able to perform. The report focuses on lessons learned through preparing the individual reports, a high level estimate of potential utility benefits, as well as insights learned about the Oregon storage market from outreach to the storage industry. PacifiCorp expects to file this final report with the Commission shortly after filing this compliance filing.

PacifiCorp intends to solicit input from stakeholders and use the key learnings identified in the final Phase 1 report to develop a revised plan for Phase 2 of Pilot Project 2. PacifiCorp expects to be prepared to file a revised Phase 2 plan for Commission approval by the end of November 2020.

Additional Items

Since Pilot Project 1 is not yet in service, the Company is unable to provide a "a narrative of EIM benefits that have been achieved," or a "quantitative evaluation of the costs and benefits of the ESS in Project #1 relative to all other ESSs operated by PacifiCorp, and a narrative discussion on whether any learnings from PacifiCorp's other storage projects can be applied in Oregon" at this time.

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[2] Some of the specific challenges caused by the coronavirus were: 1) the closure of public spaces, which made physical site visits impossible; 2) slowed communications, caused by people's transition to working from home; and 3) the appropriate prioritization of coronavirus response efforts by people engaged in community emergency response efforts, many of whom were PacifiCorp's points-of-contact at the critical facilities. TRC worked with PacifiCorp to develop a virtual site visit process for participating facilities, but that process still required a site representative to be present at the facility.

[3] Every step of the technical assessment process was completed, except the site visit. The customer was not provided a study. However, TRC was able to complete the technical assessment for the site by plugging in assumptions and synthetic data where site-specific information was unavailable.

The Company has included a copy of the annual Sustainable Transportation and Energy Plan Project Status Report (STEP Report) filed with the Utah Public Service Commission. The most recently filed STEP Report is included in this annual update as Attachment 2.

Please direct any informal correspondence and questions regarding this filing to Cathie Allen Regulatory Affairs Manager, at (503) 813-5934.

Sincerely,

Etta Lockey
Vice President, Regulation

Enclosures

CERTIFICATE OF SERVICE

I certify that I electronically filed a true and correct copy of PacifiCorp's **Third Compliance Filing – Energy Storage Pilot and Evaluation Plan Update** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

Service List
UM 1857

CREA	
BRIAN SKEAHAN PMB 409 18160 COTTONWOOD RD SUNRIVER, OR 97707 BRIAN.SKEAHAN@YAHOO.COM	GREGORY M. ADAMS **(C)** RICHARDSON ADAMS, PLLC PO BOX 7218 BOISE, ID 83702 GREG@RICHARDSONADAMS.COM
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Dated October 16, 2020.

Katie Savarin

Katie Savarin
Coordinator, Regulatory Operations

CONFIDENTIAL

Attachment 1

REDACTED

Battery Cost Analysis Assumptions

CAPITAL UP FRONT

Cost Parameter/ Technology	Description/ What does this value include?	Source (where did I get this number?)	Project #1 Specific - LOW	Project #1 Specific - MID	Project #1 Specific - HIGH	Project #1 October 2019
Energy storage equipment cost ($/kWh)	DC battery system including - The costs of the energy storage medium (Li-Ion battery cells or flow battery electrolyte) - Asociated costs of assembling these components into a DC battery system	Cost update to the Battery Energy Storgae Study for the IRP, Appendix D of the Oregon Energy Storage Project Proposal	$553,500	$922,500	$1,291,500	[redacted]
Balance of system ($/kW)	Balance of Systen Costs include - Power conversion equipment (inverter, packaging, container, and controls) - The control system - Other supporting equipment, such as thermal management, wiring and interconnection equipment, and protection of various components	Cost update to the Battery Energy Storgae Study for the IRP, Appendix D of the Oregon Energy Storage Project Proposal	$514,720	$619,280	$723,840	[redacted]
EPC Cost ($/kWh)	All direct costs for development and project management, and costs associated with a fixed price, turn-key, EPC contract	Cost update to the Battery Energy Storgae Study for the IRP, Appendix D of the Oregon Energy Storage Project Proposal	$900,000	$1,350,000	$1,800,000	[redacted]
		UP FRONT SUBTOTAL	$1,968,220	$2,891,780	$3,815,340	$3,147,638
		$/kW equivalent	$984	$1,446	$1,908	$1,574
		$/W equivalent	$0.98	$1.45	$1.91	$1.57

OWNER's COSTS

Sales tax ($)	State & local sales tax	https //www.taxrates.com/state-rates/oregon/	$0	$0	$0	$0
Interconnection application ($)	Interconnection studies costs owed to the transmission provider	http //www.pacificorp.com/tran/ts/gip/qf/oregon.html	$3,300	$7,300	$11,300	[redacted]
Interconnection (upgrades) ($)	Laydown area improvements and addition of distribution equipment	Grandview Energy Storage Detailed Integration Estimate	$446,000	$549,000	$652,000	[redacted]
Communications upgrade ($)	Portland Service Center and a Local Service Center comms modifications	Grandview Energy Storage Detailed Integration Estimate	$17,000	$17,000	$17,000	$17,000
Owner's project management ($)	Owner's direct engineering & project management	Grandview Energy Storage Detailed Integration Estimate	$54,000	$57,000	$60,000	[redacted]
AFUDC ($)	7%	RMP Capital Reporting	$174,196	$246,546	$318,895	$287,142
Cap surcharge ($)	7 - 12%	RMP Capital Reporting	$186,390	$358,019	$584,944	$416,971
		OWNER's COST SUBTOTAL	$880,887	$1,234,865	$1,644,139	$1,658,498
		$/kW equivalent	$440	$617	$822	$829
		$/W equivalent	$0.44	$0.62	$0.82	$0.83
		CAPITAL TOTAL	$2,849,107	$4,126,645	$5,459,479	$4,806,136
		$/kW equivalent	$1,425	$2,063	$2,730	$2,403
		$/W equivalent	**$1.42**	**$2.06**	**$2.73**	**$2.40**

O&M SUMMARY

Cost Parameter/ Technology	Description/ What does this value include?	Source (where did I get this number?)	Project #1 Specific - LOW	Project #1 Specific - MID	Project #1 Specific - HIGH	Project #1 Specific - High Confidence
Fixed O&M cost ($/kW-yr)	Maintenance of HVAC system, tightening of mechanical and electrical connections, cabinet touch up painting and cleaning, and landscaping maintenance, power stack and pump replacements, tightening of plumbing fixtures, tightening of mechanical and electrical connections, as well as semi-annual chemistry refresh and full discharge cycles to refresh capacity. **Does not include capacity maintenance or augmentation.**	Cost update to the Battery Energy Storgae Study for the IRP, Appendix D of the Oregon Energy Storage Project Proposal	$12,000	$17,000	$22,000	$17,000
Addition Inspection O&M ($/yr)	Monthly inspection	Range of values for Current Transmission and Distribution Substation Inspection Costs in the Albany District	$2,280	$2,778	$3,276	$2,778.00
Land Lease Costs ($/yr)			$3,525	$6,010.00	$9,018	$0.00
		O&M $/yr Equivalent	$17,805	$25,788	$34,294	$19,778
		O&M $/kW-year	**$9**	**$13**	**$17**	**$9.89**
		Equivalent O&M $/kW	$89.03	$128.94	$171.47	$98.89
		Equivalent O&M $/Watt	$0.09	$0.13	$0.17	$0.10
		TOTAL $/Watt Equivalent	**$1.51**	**$2.19**	**$2.90**	**$2.50**

Attachment 2

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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

April 30, 2020

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 Administrator

RE: **Docket No. 20-035-21—Rocky Mountain Power's Third Annual Sustainable Transportation and Energy Plan Act ("STEP") Program Status Report**

In accordance with Docket No. 16-035-36, Rocky Mountain Power (the "Company") hereby submits for filing its third Annual Sustainable Transportation and Energy Plan Act ("STEP") Program Status Report ("STEP Report"). The STEP Report contains the overall calendar year 2019 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 Utah Public Service Commission ("the Commission") dated October 12, 2017 ("Reporting Template").

The Reporting Template was designed to inform stakeholders of the STEP program's progress and funding, and the Company continues to modify and supplement the report based on feedback and recommendations from interested parties through various proceedings. A complete list of these changes is provided on pages 1.2 through 1.5 along with a reference to where the additional information can be found in the STEP Report, if applicable. The Company appreciates the feedback received so far on the STEP Report and looks forward to continued collaboration with interested parties to ensure the STEP Report is as useful as possible.

Also, the NOx Neural Network Implementation (Huntington Plant) project, Page 4.0, and the CarbonSAFE project, Page 8.0 are complete and final reports are included in this filing.

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
John.hutchins@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. 20-035-21

I hereby certify that on April 30, 2020, a true and correct copy of the foregoing was served by electronic mail to the following:

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Michele Beck	mbeck@utah.gov
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Data Request Response Center	datarequest@pacificorp.com
Jana Saba	jana.saba@pacificorp.com utahdockets@pacificorp.com

Katie Savarin

Katie Savarin
Coordinator, Regulatory Operations

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

STEP PROGRAM STATUS REPORT

For Period Ended
December 31, 2019

2019 ANNUAL STEP STATUS REPORT

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Overall STEP Program Information:

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2019 Annual STEP Status Report
STEP and USIP Accounting
CY 2019

Page No.		CY 2017	CY 2018	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	CY 2019 Total	2017-2019 Cummulative Total*
				CY 2019													
	STEP Account Beginning Balance	(15,850,031)	(19,861,068)	(23,946,249)	(24,516,425)	(25,214,174)	(24,424,754)	(24,119,511)	(23,825,606)	(23,951,249)	(23,699,725)	(23,791,236)	(23,478,140)	(23,550,338)	(23,304,970)	(23,946,249)	(15,850,031)
	Spending by Project																
2.0	EV Charge Infrastructure	487,502	1,881,703	167,183	29,552	28,147	121,399	320,862	140,899	438,389	88,439	322,975	83,267	47,199	35,828	1,824,139	4,193,344
3.0	Woody-waste Co-Fire Biomass at Hunter Unit :	-	262,837	-	-	45,738	79,084	79,472	-	110,367	-	127,071	-	147,211	-	588,943	851,780
4.0	NOx Neural Network Implementatio	457,767	207,616	115	22,243	12,568	23,451	14,256	-	39,149	-	-	39,152	1,760	78,928	231,621	897,004
5.0	Alternative NOx Reductior	131,405	26,010	-	-	-	-	-	-	-	-	-	-	-	-	-	157,415
6.0	CO2 Enhanced Coal Bed Methane (CO2 Reduction	-	73,041	0	(8,779)	10,725	124	-	28,201	-	280	11,582	-	-	-	42,133	115,174
7.0	Cryogenic Carbon Capture (Emerging CO2 Capture	160,451	530,289	-	-	309,118	95,249	-	-	123,522	-	13,843	2,635	53	167,330	711,750	1,402,490
8.0	CARBONsafe (CO2 Sequestration Site Characterizatior	150,239	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150,239
9.0	Solar Thermal Assessment (Grid Performance	-	-	-	-	20,250	-	18,500	-	-	-	-	44,307	-	-	83,057	83,057
10.0	Circuit Performance Meters (Substation Meterinc	13,676	427,349	(58,371)	122,766	(19,238)	2,208	36,388	8,333	15,271	64,263	106,295	87,497	33,364	53,002	451,777	892,802
11.0	Commercial Line Extensior	-	69,340	-	-	38,740	-	-	-	-	-	45,360	-	-	-	81,743	151,083
12.0	Gadsby Emissions Curtailmen	-	-	-	-	-	-	-	-	-	-	-	-	-	7,067	7,067	7,067
13.0	Panguitch Solar and Energy Storage Project	331,995	75,474	(1,417)	3,284	677,690	518,443	612,277	630,230	432,029	883,136	584,400	443,937	380,209	1,209,331	6,373,549	6,781,019
14.0	Microgrid Projec	-	90,713	-	-	1,007	98	-	-	782	75,829	-	-	-	-	77,717	168,430
15.0	Smart Inverter Projec	-	383,859	-	-	-	-	-	-	-	-	-	-	-	-	-	383,859
16.0	Battery Demand Response	-	-	-	-	-	-	-	-	-	-	-	-	925	3,344	4,270	4,270
17.0	Intermodal Hub	-	-	-	-	-	-	-	-	-	-	-	-	-	802,510	802,510	802,510
18.0	Advance Resiliency Management Systen	-	-	-	-	-	-	-	-	-	5,770	6,440	12,040	10,676	5,005	39,931	39,931
19.0	Utah Solar Incentive Progran	4,762,182	3,486,811	226,598	-	504,948	263,509	(301)	9,857	246,904	72,856	296,871	65,652	437,659	49,188	2,173,740	10,422,733
	Total Spending	6,495,218	7,515,042	334,109	169,066	1,629,693	1,103,565	1,081,453	817,519	1,406,412	1,190,573	1,514,838	778,487	1,059,056	2,411,533	13,493,946	27,504,205
	Surcharge Collections	(9,756,984)	(10,725,962)	(821,678)	(782,255)	(755,666)	(710,020)	(700,237)	(856,158)	(1,068,112)	(1,195,600)	(1,115,577)	(765,041)	(728,357)	(508,773)	(10,007,474)	(30,490,421)
	Ending Monthly Balance before Carrying Charge	(19,111,798)	(23,071,989)	(24,433,819)	(25,129,614)	(24,340,147)	(24,031,209)	(23,738,296)	(23,864,245)	(23,612,949)	(23,704,751)	(23,391,975)	(23,464,693)	(23,219,639)	(21,402,211)	(20,459,778)	(18,836,247)
	Carrying Charge	(749,270)	(874,261)	(82,606)	(84,559)	(84,607)	(88,303)	(87,310)	(87,005)	(86,776)	(86,485)	(86,165)	(85,644)	(85,331)	(81,586)	(1,026,377)	(2,649,907)
	Ending Monthly Balance	(19,861,068)	(23,946,249)	(24,516,425)	(25,214,174)	(24,424,754)	(24,119,511)	(23,825,606)	(23,951,249)	(23,699,725)	(23,791,236)	(23,478,140)	(23,550,338)	(23,304,970)	(21,483,797)	(21,486,154)	(21,486,154)

*the STEP Account Begninning Balance of ($15,850,031) is the begninng balance as of January 2017

2019 Annual STEP Status Report
STEP/DSM Assets/Liabilities
(Based on STEP Legislation)

CY 2017

	Program Expenditures	Accrued Program Expenditures	Amortization of Expense (over 10 years)	Unused DSM Revenue Collections	Carrying Charge	End Balance	Cash Basic Accumulated Balance
					10.65%		
FY16	-	2,693,388	-	(7,097,889)		(4,404,501)	(7,097,889)
1	2,648,142	262,689	(11,010)	(5,596,470)	(76,126)	(7,177,276)	(10,133,354)
2	3,754,612	348,093	(37,611)	(5,851,627)	(99,406)	(9,063,215)	(12,367,385)
3	3,478,015	(117,206)	(67,973)	(4,670,909)	(115,356)	(10,556,644)	(13,743,608)
4	4,355,254	586,848	(100,399)	(4,668,416)	(123,810)	(10,507,168)	(14,280,980)
5	3,686,017	(291,172)	(134,079)	(4,563,595)	(131,233)	(11,941,231)	(15,423,870)
6	3,848,077	669,594	(164,408)	(5,989,272)	(147,118)	(13,724,357)	(17,876,590)
7	3,924,229	1,047,010	(197,648)	(7,728,712)	(176,414)	(16,855,892)	(22,055,136)
8	4,036,553	(195,749)	(231,059)	(4,577,217)	(199,164)	(18,022,529)	(23,026,024)
9	2,972,860	924,940	(260,144)	269,800	(191,121)	(14,306,194)	(20,234,629)
10	4,678,938	39,552	(292,027)	269,150	(158,921)	(9,769,503)	(15,737,489)
11	6,803,166	(694,191)	(339,869)	345,359	(109,457)	(3,764,495)	(9,038,290)
12	9,380,581	(1,204,040)	(407,301)	407,396	(38,588)	4,373,553	303,797
Estimate	-	-	-	4,322	(8,859)	4,369,016	299,260
Total	53,566,445	4,069,756	(2,243,529)	(49,448,082)	(1,566,714)		
			55,392,672		(51,014,796)	4,377,875	
			Total Asset		Total Liabilities		

CY 2018

	Program Expenditures	Accrued Program Expenditures	Amortization of Expense (over 10 years)	Unused DSM Revenue Collections	Carrying Charge	End Balance	Cash Basic Accumulated Balance
					9.21%		
FY17	-	4,069,756	-	299,260		4,369,016	299,260
1	3,568,395	522,546	(461,232)	(2,054,799)	6,335	5,950,261	1,357,959
2	3,374,756	(255,983)	(490,143)	(4,171,129)	5,485	4,413,248	76,929
3	4,020,585	(809,314)	(521,052)	(4,312,160)	(2,528)	2,788,779	(738,226)
4	3,506,710	(239,128)	(552,362)	(4,393,042)	(11,187)	1,099,771	(2,188,106)
5	3,627,311	581,878	(582,102)	(4,227,927)	(21,332)	477,599	(3,392,156)
6	4,220,629	699,578	(614,788)	(5,526,489)	(33,405)	(776,876)	(5,346,209)
7	5,022,885	384,297	(653,261)	(7,346,126)	(52,454)	(3,421,535)	(8,375,165)
8	4,164,510	868,008	(691,624)	(7,635,830)	(80,255)	(6,796,726)	(12,618,364)
9	2,671,925	454,900	(720,025)	(6,662,806)	(114,924)	(11,167,655)	(17,444,193)
10	4,757,938	(305,047)	(751,069)	(4,673,096)	(136,441)	(12,275,370)	(18,246,861)
11	6,769,886	(2,282,310)	(799,057)	(4,176,547)	(133,159)	(12,896,557)	(16,585,738)
12	5,518,134	134,805	(850,260)	(4,836,366)	(127,942)	(13,058,187)	(16,882,172)
Estimate	-	-	-		877	(13,057,310)	(16,881,295)
Total	51,223,665	3,823,986	(7,686,975)	(59,717,055)	(700,930)		
				-			
			47,360,676		(60,417,985)	(13,057,310)	
			Total Asset		Total Liabilities		

CY 2019

	Program Expenditures	Accrued Program Expenditures	Amortization of Expense (over 10 years)	Unused DSM Revenue Collections	Carrying Charge	End Balance	Cash Basic Accumulated Balance
					9.21%		
FY18	-	3,823,986	-	(16,881,295)		(13,057,310)	(16,881,295)
1	2,226,187	409,558	(882,851)	(4,647,371)	(142,243)	(16,094,030)	(20,327,574)
2	3,125,236	(851,191)	(905,431)	9,742,037	(110,111)	(5,093,489)	(8,475,842)
3	3,363,644	929,979	(932,571)	(3,986,014)	(71,019)	(5,789,470)	(10,101,802)
4	4,141,721	(298,685)	(963,923)	(3,566,324)	(79,022)	(6,555,703)	(10,569,350)
5	3,750,564	(389,337)	(996,702)	(3,546,409)	(84,161)	(7,821,747)	(11,446,057)
6	3,030,543	1,099,368	(1,025,077)	(4,533,002)	(97,548)	(9,347,465)	(14,071,142)
7	4,107,773	377,100	(1,055,307)	(5,916,482)	(118,987)	(11,953,367)	(17,054,144)
8	4,296,799	101,144	(1,090,082)	(6,793,244)	(144,654)	(15,583,403)	(20,785,325)
9	5,468,058	(705,972)	(1,130,583)	(6,211,505)	(166,719)	(18,330,125)	(22,826,074)
10	4,265,394	757,369	(1,171,487)	(3,787,195)	(177,851)	(18,443,895)	(23,697,214)
11	5,000,367	360,815	(1,209,461)	(3,584,184)	(181,083)	(18,057,442)	(23,671,575)
12	8,872,512	276,491	(1,267,099)	(4,176,107)	(168,519)	(14,520,163)	(20,410,787)
Estimate	-	-	-		9,874	(14,510,289)	(20,400,913)
Total	51,648,796	5,890,625	(12,630,573)	(57,887,094)	(1,532,043)		
				-			
			44,908,848		(59,419,137)	(14,510,289)	
			Total Asset		Total Liabilities		

2019 ANNUAL STEP STATUS REPORT

For Period Ended December 31, 2019

List of Report Changes in Compliance with Commission Orders and Other Commitments

The following is a list of modifications to the STEP Report, which have been suggested by interested parties in various dockets pertaining to STEP. Each item is listed along with the source of the change and where the recommendation was incorporated into the STEP Report or otherwise provided.

Docket No. 18-035-16 (First STEP Report)

Several recommendations were proposed by parties in response to the First STEP Report. Exhibit A, which accompanied the reply comments of Rocky Mountain Power filed on July 27, 2018, summarized the parties' recommendations. A revised Exhibit A is provided below containing the items that were approved by the Commission, along with a new column that provides a reference to how the Company incorporated the recommendation:

Summary of Requirements from 1st STEP Report Docket No. 18-035-16

Topic	Division	Office	SWEEP/UCE	Compliance Reference
USIP	1) Include a spreadsheet that reconciles USIP expenditures and ending balances that correlate to the STEP Report, RMP Exhibit A.			See Page 19.0
Overall DSM/STEP Liability Account	2) Include a brief summary and spreadsheet explaining the DSM/STEP Liability and Asset balancing accounts.			See Page 1.1
Electric Vehicle	3) Include a spreadsheet explaining the Electric Vehicle ("EV") Program expenditures.			See page 2.4 and Exhibits 2A-2E
	4) Provide accounting and explanations in the annual report that demonstrate the EV Program in a more transparent manner.	1) Table 1 EVCI should be modified such that the accounting information is presented in a more easily understood format.		See page 2.0
		2) Table 3 EVCI should include the date each custom project was accepted by the Company.		See Exhibit 2-A, column "creation date"
	5) The parties should meet to discuss how to proceed with accounting for EV custom project incentives and other commitments.			Discussed at STEP Collaborative on October 23, 2018
	6) Provide at a minimum, a status report for the additional filing requirements for the EV Program.			Discussed at STEP Collaborative on October 23, 2018
			1) modify future reports to include: total number of workplace charging ports by county, the number of employers and sites, the average and range of total costs for each charging station.	See Table 2 and Exhibit 2-A in the EV program report
Clean Coal	7) File with the Commission to reallocate funds from the Alternative NOx Emission Control Technology to another program.	5) Recommends that the Commission clearly indicate that the funds associated with this project are no longer authorized to be spent unless and until the Company receives approval for a reallocation or new proposal that is found to be in the public interest.		Application Submitted 11/13/18, approved 2/6/19
Panguitch Battery Storage		3) The Company should provide an explanation on the battery storage project accounting and milestones in reply comments in this docket.		See Docket No. 18-035-16 RMP Reply Comments p. 3-4
Overall Report	8) The Division suggests that RMP provide an explanation for any external OMAG expense in future reports.			Explanation of external OMAG is provided where applicable
		4) The Company should meet with interested parties to discuss potential modifications and/or enhancements to the STEP Annual Status Report.		STEP Collaborative held on October 23, 2018

Docket No. 16-035-36 February 6, 2019 Commission Order

On November 13, 2018 the Company filed for approval to modify the funding amounts previously authorized by the STEP Act. The Commission approved the Company's request in an order issued February 6, 2019. The order included the following additional reporting requirements for the annual STEP report:

Summary of Requirements from February 6, 2019 Order (Docket No. 16-035-36)

Topic	Requirement	Compliance Reference
Commercial Line Extension	Include: 1) number of applications submitted 2) number of applications selected to receive incentives 3) whether recipients received multiple incentive awards 4) if awarded: a) size of project b) cost c) amount of incentive d) number of charging stations e) number of conduit extensions installed for future EV charging locations as provided for in Regulation No. 13	Page 11.0-11.1
Storage and Solar Technology Project	Meet with parties to discuss:	Meeting held on February 25, 2019
	1) Provide requested project cost data	Requested data was provided through discovery on March 25, 2019 in Docket No. 16-035-36 OCS 21.1 3rd Supplemental
	2) Develop reporting requirements for this data in annual STEP reports going forward	None at this time although parties anticipate additional reporting requirements may develop as the project moves forward
	3) Discuss types of info to be provided after STEP ends (and in what manner)	

***********************************NEW***********************************

Docket No. 16-035-36 June 28, 2019 Commission Order

On March 8, 2019 the Company filed for approval of three new innovative utility programs under the STEP Act. The Commission approved the Company's request in an order issued June 28, 2019. The order included the following additional reporting requirements for the annual STEP report:

Summary of Requirements from June 28, 2019 Order (Docket No. 16-035-36)		
Topic	**Requirement**	**Compliance Reference**
Intermodal Hub	STEP Annual Report include progress on achieving the project's four tasks outlined in the Application	Starting on Page 17.0
	- Provide cost benefit analysis at project conclusion (Office)	will be provided at conclusion
	- Report on any elements that are not resolved within appropriate timeframes (Office)	will be reported if applicable
EXIT strategy Meeting	Include a summary of meeting in STEP Report (Division & PSC recommendation)	See Page 1.6
Ongoing OMAG	reporting on ongoing OMAG (Office)	See Page 1.6
Other	Quarterly updates w/ project accounting (Division and Office)	Ongoing, next update scheduled May 19, 2020
Battery Demand Response	comprehensive performance update report - mid year and in STEP report (WRA - RMP reply comments)	Nothing to report at this time. Updates will begin in Q4 2020
	- proof of permit from city (Division)	filed Docket No. 16-035-36, 8/28/19
	- legal protections for ratepayers (Division)	filed Docket No. 16-035-36, 4/17/20

<u>Docket No. 19-035-T12 August 20, 2019 Commission Order</u>

On July 23, 2019 the Company filed for approval to refund $3.06 million in surplus revenues collected under the discontinued Schedule 107 related to the canceled Utah Solar Incentive Program through a reduction in the STEP surcharge collections through Schedule 196. The Commission approved the Company's request to refund the revenues over 12 months beginning November 1, 2019. The order included the following additional reporting requirement for the annual STEP report:

Summary of Requirements from August 20, 2019 Order (Docket No. 19-035-T12)		
Topic	**Requirement**	**Compliance Reference**
USIP	Order: include the additional USIP balance reporting that the DPU requested in its August 9, 2019 comments in RMP's annual STEP and USIP status reports. DPU comments:The Division recommends the Commission direct RMP to include in its Annual STEP Report and Annual USIP Report an accounting of the USIP balance including the current variable charges explained above.	See USIP Explanation beginning on Page 19.0.

Docket No. 19-035-17 (Second STEP Report)

Below is a summary recommendations from the 2nd annual STEP report:

Summary of Requirements from 2nd STEP report (Docket No. 19-035-17)		
Topic	**Requirement**	**Compliance Reference**
USIP	coordinate and add detail on USIP	See USIP Explanation beginning on Page 19.0.
Accounting Summary	add footnote - see revised exhibit A (Office)	Footnote added to Page 1.0
Line extension	- specify number of applications received better - clarify if anyone received multiple rewards - check column labels on table 2	Pages 11.0-11.2

STEP Exit Strategy and Planning Meeting
November 12, 2019

Attendees

In person:
Brenda Salter, DPU
Justin Jetter, AG's Office for the DPU
Bob Davis, DPU
Cheryl Murray, OCS
Kate Bowman, UCE
Sophie Hayes, WRA
Kelly Francone, UAE
Jana Saba, RMP
Shawn Grant, RMP

On the phone:
Kayla Bishop, RMP
Artie Powell, DPU
Robert Meredith, RMP

Discussion Topics & Meeting Summary

1. <u>Remaining Unspent STEP funds</u>
   The company shared that it estimates that, based on current STEP budget projections, some remaining STEP funds is likely. Participants discussed possible uses of any remaining funds including refund to customers, continuation of a current STEP project, or a new project. Many expressed a preference to refund any excess funds to customers. Parties also discussed the possibility of retaining a portion of the funds in a regulatory liability to use for any ongoing costs of STEP projects beyond 2021 as discussed in more detail below. Parties decided to meet again after the conclusion of STEP once the amount of remaining funds is certain to collaborate on the use of the funds. If a refund is the preferred approach, the refund could be proposed as part of the final annual STEP filing, due to be filed in 2022.
   a. <u>USIP balance end of 2023 *(reference Docket No. 19-035-T12, 7/23/19 Tariff Filing)*</u>
      Although the USIP incentive payouts are scheduled to go through 2023, the majority of the USIP incentives will be paid at the time the use of any excess STEP funds is being determined (Q2/Q3 of 2022). Therefore parties discussed that it may make sense to combine the excess USIP funds with the excess STEP funds and apply the same treatment. This item will also be discussed at the conclusion of STEP.
2. <u>Ongoing STEP costs</u>
   a. <u>Reporting</u>

Type, granularity, format, and timing of information *(reference Docket No. 16-035-36, 6/28/19 Report and Order)*

Parties agree that the company will provide the detailed information by project for any ongoing costs associated with STEP projects when it files its final reports on the STEP projects in 2022.

b. Ongoing benefits

c. Regulatory liability

i. Terms (length, carrying charge, etc)

ii. What to do with any remaining balance

The parties discussed the option of setting aside a portion of any remaining STEP funds to use for ongoing costs. It was determined that parties would discuss once the STEP program concludes after 2021 when the magnitude of the expected ongoing costs can be reasonably estimated.

3. Final accounting

a. EV program use or lose and September fiscal year

i. The EV program prescriptive incentives for AC Level 2 and DC Fast Chargers follow an October 1st through September 30th fiscal year, while Grant-based custom projects and partnerships follow a January 1st through December 31st program year. Accounting for the EV program in this manner helps ensure funding for the EV program is used efficiently, and helps avoid the unnecessary loss of funds due to the use-it-or-lose-it nature of the EV program's funding.

b. Can projects be allowed a few months close out process? Or must all costs stop 12/31/2021?

The STEP period is 2017-2021. The company informed the meeting participants that it may take time to close out the accounting and payouts associated with STEP projects, which may necessitate a delay of the final STEP report – due April 30, 2021 – to capture the final accounting for the projects. The group generally discussed allowing the company until March 31, 2022 to finalize the accounting for the projects. The company would request a delay from the Commission to delay the final report filing – likely to June 30, 2022.

4. Final reporting timing

In early 2022, the company would request permission from the Commission to delay the final report filing – from April 30, 2022 to possibly June 30, 2022. Note, the final report is intended to represent the final annual STEP report that presents CY 2021 actual information. This is not referencing the report and recommendation to the Legislature as referenced in 54-20-106.

5. Exit Meeting report to the PSC *(reference Docket No. 16-035-36, 6/28/19 Report and Order)*

STEP Project Report

Period Ending December 31, 2019[1]

STEP Project Name:

Electric Vehicle ("EV") Charging Infrastructure:

1. EV Time of Use ("TOU") Pilot – Schedule 2E;
2. Plug-in EV Pilot Incentive Program – Schedule 120; and
3. Plug-in EV 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.

2019 EV PROGRAM BUDGET ACCOUNTING

Table 1 below is an accounting of how the $2 million 2019 EV Program budget was allocated. Prescriptive incentives represent measures that follow a program fiscal year of October 1st through September 30th, while custom incentives for committed funds follow the calendar year. Prescriptive incentives in Table 1 were completed during the EV Program's fiscal year. Custom incentives in Table 1 were committed to custom projects that the Company approved through the customer application process. Incentives for custom projects will be paid to customers upon the actual completion of their projects. Additional details and support for Table 1 prescriptive incentives can be found in Exhibit 2-A.

Table 1 – 2019 EV Program Budget Accounting

2019 EV Program Budget Costs/Commitments				
Category	**Prescriptive Incentives**	**Committed Custom Incentives**	**Program Management**	**Total**
Time of Use Rate Sign-up	$29,400	-	-	$29,400
Time of Use Load Research Study	$17,000	-	-	$17,000
Time of Use Meters	-	-	$554.48	$554.48
Non-Residential AC Level 2 Chargers – Single Port	$108,013.58	-	-	$108,013.58
Non-Residential AC Level 2 Chargers – Multi-Port	$520,440.58	-	-	$520,440.58
Non-Residential & Multi-Family DC Fast Chargers	$265,678.33	-	-	$265,678.33
Custom Projects	-	$669,439.49	-	$669,439.49
Administrative Costs	-	-	$127,958.88	$127,958.88
Outreach & Awareness	-	-	$261,514.66	$261,514.66
Total	$940,532.49	$669,439.49	$390,028.02	**$2,000,000**

[1] Incentive payments for the Time of Use Pilot, Non-Residential AC Level 2 Chargers, and Non-Residential & Multi-Family DC Fast Chargers (prescriptive incentives) from October 1, 2019, through December 31, 2019, used 2020 incentive funds, consistent with the program's fiscal year structure approved in Docket No. 16-035-36, and will be included in the reporting period for the 2020 EV Program budget.

2019 PRESCRIPTIVE INCENTIVE LOCATIONS

Table 2 below is a breakout by city for prescriptive incentive equipment installations and TOU sign-ups from the 2019 EV Program fiscal year occurred (October 1, 2018 through September 30, 2019). There were a combined total of 573 AC Level 2 and DC Fast charging ports installed for public and/or workplace use. Of those, 460 ports were installed across 86 employers and 113 ports were installed across 4 multi-family properties.

Table 2 – EV Charger Installations and Time-of-Use Sign-ups by City

City (ut)	DC Fast Charger Single Port	AC Level 2 Chargers		TOU Rate Sign-ups	
		Multi-Port	Single Port	Option 1	Option 2
Alta		1	2		
American Fork					2
Bluff			1		
Bluffdale				2	1
Cedar city			2		1
Cedar fort					1
Cedar hills					1
Centerville			4		
Clearfield		11			
Coalville		5			
Corinne			8		
Cottonwood Heights		12	23		1
Draper		14	2	1	8
Erda				1	1
Farmington				2	3
Farr west					1
Francis				1	
Grantsville					2
Harrisville					1
Herriman				3	6
Highland				2	
Hill Air Force Base			2		
Holladay					1
Kaysville					1
Lake point			2		
Layton	2				7
Liberty			2		1
Logan		50			
Mapleton				1	
Marriott Slaterville					1
Midvale		7	2		
Millcreek		1	3	5	8
Moab		2			
Murray					1
New Harmony					1
Nibley				1	1

City (ut)	DC Fast Charger Single Port	AC Level 2 Chargers		TOU Rate Sign-ups	
		Multi-Port	Single Port	Option 1	Option 2
North logan					2
North Ogden					3
North Salt Lake				1	1
Ogden			2	1	4
Orem			8		2
Park City	8	9		1	4
Plain City				1	
Pleasant Grove		7			
Riverton				2	1
Roy					1
Salt Lake City		79	71	2	9
Sandy		1	3	1	5
Saratoga Springs					1
South Jordan					2
South Salt Lake			7	1	2
Stansbury Park				1	2
Summit County			1		
Syracuse				1	1
Taylorsville		2	1	2	3
Tooele				1	
Toquerville					1
Tremonton			6		1
Vernal					1
Vineyard				1	1
Wellsville					1
West Bountiful				1	1
West Haven					1
West Jordan				2	2
West Valley City		4	1		4
White City				1	
Woods Cross					1
Total	**10**	**205**	**153**	**39**	**108**

CUSTOM PROJECTS

Custom Projects 14 through 16 are listed in Table 3 below, which includes a description, incentive amount, and equipment to be installed from customer applications that were approved by the Company and committed from the 2019 EV Program budget during the 2019 calendar year. A summary of the 2019 EV Program budget committed funds for custom projects can be found in Exhibit 2-B. Incentives for custom projects will actually be paid to customers upon the completion of their projects, and may be adjusted downward based on the actual equipment that gets installed and actual equipment costs. The 2019 custom projects are expected to be completed and paid in 2020.

Custom Projects 1 through 9 were reported in the 2017 Annual STEP report representing $1,359,874 of committed funds from the 2017 EV Program budget. Custom Projects 10 through 13 were reported in the 2018 Annual STEP report representing $998,500 of committed funds from the 2018 EV Program budget. Exhibits 2-B and 2-C provide updated information on committed custom projects. There were a combined total of 67 AC Level 2 and DC Fast charging ports installed for workplace/public use from completed custom projects in 2019.

Table 3 – 2019 EV Program Budget Custom Project Commitments[2]

Custom Projects	Incentive	Description	Equipment Type
Project 14 Accepted June 2019	$330,000	A major healthcare provider is committed to provide vehicle charging to its customers and caregivers. Its goal is to install EV charging at all of its campuses, clinics and business locations. The business is committed to maintaining a consistent model and technology for ease of our customers, maintenance, and data. The equipment also provides us with the needed billing functionality required for Stark laws regarding our physician population. The project will include 66 AC Level 2 Chargers at 33 different locations.	66 AC Level 2 Charging Ports
Project 15 Accepted June 2019	$170,000	A city is planning to install 45 AC Level 2 electric vehicle chargers. The city has a goal to promote elecrification and wants charging to convenient for residents and visitors	45 AC Level 2 Charging Ports
Project 16 Accepted December 2019	$169,439	A government agency will be installing several electric vehicle chargers throughout the state of Utah. Specific sites have been identified in areas where electric vehicle charging is lacking. The intent of this project is to allow EV drivers to be able to charge throughout the state.	18 AC Level 2 Charging Ports and 10 DC Fast Charger Port
Total 2019 EV Budget Commitments	$669,439	---	129 AC Level 2 Charging Ports, 10 DC Fast Charging Ports

[2] Custom projects listed in Table 3 may evolve and are expected be completed throughout 2020. Actual incentive amounts and installed equipment will be included in subsequent reports for completed custom projects.

2019 CALENDAR YEAR ACCOUNTING

Table 4 below provides an accounting of how the EV Program costs for calendar year 2019 are posted to SAP (the Company's accounting system), and reconciles to the STEP accounting. The amount of funds that actually post to SAP in a calendar year is dependent upon when projects complete. For example, most of the custom projects that were committed in 2018 from the 2018 EV Program budget completed in 2019, which means the funds associated with those custom projects posted to SAP in 2019. So while SAP accounting reflects those costs in 2019, they were, in fact, counted towards the \$2 million 2018 EV Program budget. Additionally, prescriptive incentives follow a fiscal year of October 1st through September 30th. As such, prescriptive incentives for the 2019 EV Program budget include the timeframe of October 1, 2018 through September 30, 2019, with Q4 2019 prescriptive incentive costs being counted as part of the 2020 EV Program budget. So even though SAP accounting includes prescriptive incentive costs from October 1, 2019, through December 31, 2019, as part of the calendar year, costs during that timeframe for prescriptive incentives are counted towards the \$2 million 2020 EV Program budget. Likewise, the prescriptive incentive costs during the timeframe of October 1, 2018, through December 31, 2018, are captured in SAP for that calendar year, but were counted towards the \$2 million 2019 EV Program budget, consistent with the fiscal year of the EV Program for prescriptive incentives. Exhibit 2-D provides SAP year over year accounting for each calendar year, which reconciles to the STEP accounting, and Exhibit 2-E provides a year over year accounting for how each \$2 million EV Program year budget was allocated.

Table 4 – 2019 Calendar Year Actual SAP Postings

EV Program Actual Postings in SAP by Calendar Year	
Category	**CY 2019**
Time of Use Rate Sign-up	\$28,600
Time of Use Load Research Study	\$17,000
Time of Use Meters	\$554.48
Non-Residential AC Level 2 Chargers – Single Port	\$108,565.43
Non-Residential AC Level 2 Chargers – Multi-Port	\$507,769.60
Non-Residential & Multi-Family DC Fast Chargers	\$265,678.33
Custom Projects	\$506,497.68
Administrative Costs	\$127,958.88
Outreach & Awareness	\$261,514.66
Total	**\$1,824,139.06**

2019 ELECTRIC VEHICLE INCENTIVE PROGRAM ACTIVITIES

Time of Use and Load Research Study

A total of 147 customers received incentives with 2019 EV Program budget funds for participating in the Time of Use program, apart from the load research study. By the end of the EV Program's 2019 fiscal year, 273 customers were enrolled in the Time of Use program. During 2019, the load research study concluded and participants were surveyed.

EV Program Changes

On November 18, 2019, the Company filed Advice No. 19-16 in Docket No. 19-035-T16 to adjust existing incentives, add program controls, and to add a new offering for residential customers. Incentives for non-residential and multi-family AC Level 2 Chargers were decreased to better align with the Utah Department of Environmental Quality's incentive program and to allow for additional participation due to steady partication growth. Program controls were also added to help prevent scenarios that may have resulted in customers receiving tens of thousands of dollars more than the actual cost of their equipment. Lastly, a new offering for residential customers was added to the EV Program, providing an incentive of up to $200 for residential AC Level 2 Chargers. These proposed program changes were approved by the Commission in their order issued December 31, 2019, with an effective date of January 1, 2020.

Attachments:

- Exhibit 2-A: 2019 EV Program Budget Prescriptive Incentives
- Exhibit 2-B: EV Program Custom Project Committed Funds and Expenditures
- Exhibit 2-C: EV Program Custom Project Details Year Over Year
- Exhibit 2-D: EV Program Actual SAP Postings by Calendar Year
- Exhibit 2-E: EV Program Budget Allocations Year Over Year

Exhibit 2-A

2019 EV Program Budget Prescriptive Incentives

EV Program Prescriptive Incentives (2019 Budget Funds)

Project Name	Measure_Name	Quantity	Number of Ports	Customer Incentive	Measure Cost	Creation Date	City	Zip Code
EVUT_265370	EV DC Fast Charger (single port)	8	8	$ 240,000.00	$ 686,656.00	2/1/2019	PARK CITY	84060
EVUT_278367	EV DC Fast Charger (single port)	2	2	$ 25,678.33	$ 34,237.77	6/4/2019	LAYTON	84041
EVUT_243565	EV Level 2 Charger (multi port)	1	2	$ 3,500.00	$ 5,364.00	10/2/2018	MILLCREEK	84117
EVUT_247305	EV Level 2 Charger (multi port)	2	4	$ 4,016.85	$ 5,355.80	11/5/2018	Pleasant Grove	84062
EVUT_247487	EV Level 2 Charger (multi port)	1	2	$ 2,008.43	$ 2,677.90	11/5/2018	CLEARFIELD	84015
EVUT_248438	EV Level 2 Charger (multi port)	5	10	$ 10,042.13	$ 13,389.50	11/7/2018	MIDVALE	84047
EVUT_249771	EV Level 2 Charger (multi port)	12	24	$ 16,046.10	$ 21,394.80	11/13/2018	SLC	84116
EVUT_252210	EV Level 2 Charger (multi port)	1	2	$ 3,500.00	$ 4,700.00	12/14/2018	DRAPER	84020
EVUT_253677	EV Level 2 Charger (multi port)	3	6	$ 6,025.27	$ 8,033.70	12/18/2018	COTTONWOOD HEIGHTS	84121
EVUT_266670	EV Level 2 Charger (multi port)	2	4	$ 2,575.65	$ 3,434.20	2/11/2019	SALT LAKE CITY	84109
EVUT_267047	EV Level 2 Charger (multi port)	6	12	$ 12,050.55	$ 16,067.40	2/19/2019	SALT LAKE CITY	84115
EVUT_267803	EV Level 2 Charger (multi port)	2	4	$ 6,852.00	$ 9,136.00	3/8/2019	TAYLORSVILLE	84129
EVUT_267919	EV Level 2 Charger (multi port)	5	10	$ 10,042.13	$ 13,389.50	3/12/2019	PARK CITY	84098
EVUT_272631	EV Level 2 Charger (multi port)	4	8	$ 8,037.00	$ 10,716.00	4/16/2019	SLC	84104
EVUT_272632	EV Level 2 Charger (multi port)	5	10	$ 10,042.13	$ 13,389.50	4/16/2019	SLC	84116
EVUT_272633	EV Level 2 Charger (multi port)	4	8	$ 8,033.70	$ 10,711.60	4/16/2019	West Valley City	84119
EVUT_273033	EV Level 2 Charger (multi port)	10	20	$ 10,111.50	$ 13,482.00	4/24/2019	CLEARFIELD	84016
EVUT_275866	EV Level 2 Charger (multi port)	1	2	$ 3,500.00	$ 4,700.00	5/9/2019	PARK CITY	84098
EVUT_277937	EV Level 2 Charger (multi port)	5	10	$ 15,000.00	$ 20,000.00	5/23/2019	COTTONWOOD HEIGHTS	84121
EVUT_278376	EV Level 2 Charger (multi port)	1	2	$ 2,008.43	$ 2,677.90	6/4/2019	DRAPER	84020
EVUT_278377	EV Level 2 Charger (multi port)	2	4	$ 5,068.50	$ 6,758.00	6/4/2019	MIDVALE	84047
EVUT_280009	EV Level 2 Charger (multi port)	2	4	$ 7,000.00	$ 10,670.00	6/21/2019	COALVILLE	84017
EVUT_280009	EV Level 2 Charger (multi port)	3	6	$ 10,278.00	$ 13,704.00	6/21/2019	COALVILLE	84017
EVUT_280192	EV Level 2 Charger (multi port)	2	4	$ 4,227.45	$ 5,636.60	6/25/2019	PLEASANT GROVE	84062
EVUT_280496	EV Level 2 Charger (multi port)	4	8	$ 8,033.70	$ 10,711.60	6/26/2019	SALT LAKE CITY	84106
EVUT_281381	EV Level 2 Charger (multi port)	3	6	$ 3,434.17	$ 4,578.90	7/3/2019	SALT LAKE CITY	84108
EVUT_281502	EV Level 2 Charger (multi port)	2	4	$ 7,000.00	$ 14,166.00	7/11/2019	Salt Lake City	84115
EVUT_281502	EV Level 2 Charger (multi port)	1	2	$ 3,500.00	$ 6,569.00	7/11/2019	Salt Lake City	84115
EVUT_282407	EV Level 2 Charger (multi port)	4	8	$ 8,033.70	$ 10,711.60	7/16/2019	SALT LAKE CITY	84116
EVUT_283335	EV Level 2 Charger (multi port)	4	8	$ 8,454.90	$ 11,273.20	7/30/2019	COTTONWOOD HEIGHTS	84047
EVUT_283463	EV Level 2 Charger (multi port)	1	2	$ 1,144.72	$ 1,526.30	8/5/2019	Sandy	84070
EVUT_282954	EV Level 2 Charger (multi port)	1	2	$ 3,500.00	$ 4,700.00	8/14/2019	PARK CITY	84098
EVUT_284278	EV Level 2 Charger (multi port)	50	100	$ 137,812.50	$ 183,750.00	8/14/2019	LOGAN	84321
EVUT_284432	EV Level 2 Charger (multi port)	7	14	$ 24,500.00	$ 33,789.00	8/16/2019	SALT LAKE CITY	84114
EVUT_284432	EV Level 2 Charger (multi port)	8	16	$ 27,186.00	$ 36,248.00	8/16/2019	SALT LAKE CITY	84114
EVUT_284437	EV Level 2 Charger (multi port)	4	8	$ 14,000.00	$ 19,308.00	8/16/2019	SALT LAKE CITY	84116
EVUT_284439	EV Level 2 Charger (multi port)	7	14	$ 24,500.00	$ 33,789.00	8/16/2019	DRAPER	84020
EVUT_284441	EV Level 2 Charger (multi port)	5	10	$ 17,500.00	$ 24,135.00	8/16/2019	DRAPER	84020
EVUT_284442	EV Level 2 Charger (multi port)	8	16	$ 27,186.00	$ 36,248.00	8/16/2019	SALT LAKE CITY	84111
EVUT_284444	EV Level 2 Charger (multi port)	2	4	$ 7,000.00	$ 9,654.00	8/16/2019	SALT LAKE CITY	84114
EVUT_284861	EV Level 2 Charger (multi port)	2	4	$ 7,000.00	$ 9,400.00	8/20/2019	MOAB	84532
EVUT_286344	EV Level 2 Charger (multi port)	3	6	$ 3,167.10	$ 4,222.80	8/29/2019	SALT LAKE CITY	84104
EVUT_286374	EV Level 2 Charger (multi port)	1	2	$ 910.57	$ 1,214.10	9/3/2019	ALTA	84092
EVUT_285124	EV Level 2 Charger (multi port)	3	6	$ 10,500.00	$ 14,100.00	9/4/2019	PLEASANT GROVE	84062
EVUT_286959	EV Level 2 Charger (multi port)	4	8	$ 14,000.00	$ 22,512.00	9/10/2019	SALT LAKE CITY	84112
EVUT_288400	EV Level 2 Charger (multi port)	2	4	$ 2,111.40	$ 2,815.20	9/24/2019	PARK CITY	84060
EVUT_243682	EV Level 2 Charger (single port)	4	4	$ 2,481.75	$ 3,309.00	10/4/2018	SALT LAKE CITY	84101
EVUT_243684	EV Level 2 Charger (single port)	1	1	$ 444.75	$ 593.00	10/4/2018	SOUTH SALT LAKE	84115

Project Name	Measure_Name	Quantity	Number of Ports	Customer Incentive	Measure Cost	Creation Date	City	Zip Code
EVUT_243684	EV Level 2 Charger (single port)	3	3	$ 1,134.00	$ 1,512.00	10/4/2018	SOUTH SALT LAKE	84115
EVUT_243685	EV Level 2 Charger (single port)	4	4	$ 1,317.00	$ 1,756.00	10/4/2018	SLC	84119
EVUT_243686	EV Level 2 Charger (single port)	1	1	$ 329.25	$ 439.00	10/4/2018	ALTA	84092
EVUT_243687	EV Level 2 Charger (single port)	2	2	$ 658.50	$ 878.00	10/4/2018	SANDY	84093
EVUT_244360	EV Level 2 Charger (single port)	3	3	$ 3,255.75	$ 4,341.00	10/18/2018	SALT LAKE CITY	84101
EVUT_244361	EV Level 2 Charger (single port)	2	2	$ 4,485.00	$ 5,980.00	10/18/2018	COTTONWOOD HEIGHTS	84121
EVUT_244362	EV Level 2 Charger (single port)	6	6	$ 13,455.00	$ 17,940.00	10/18/2018	COTTONWOOD HEIGHTS	84121
EVUT_244646	EV Level 2 Charger (single port)	2	2	$ 750.00	$ 1,000.00	10/23/2018	CEDAR CITY	84720
EVUT_244858	EV Level 2 Charger (single port)	2	2	$ 1,243.50	$ 1,658.00	10/30/2018	OGDEN	84414
EVUT_244859	EV Level 2 Charger (single port)	8	8	$ 4,230.00	$ 5,640.00	10/30/2018	CORINNE	84307
EVUT_245004	EV Level 2 Charger (single port)	4	4	$ 3,215.40	$ 4,287.20	11/1/2018	OREM	84097
EVUT_248404	EV Level 2 Charger (single port)	2	2	$ 658.50	$ 878.00	11/5/2018	TREMONTON	84337
EVUT_250817	EV Level 2 Charger (single port)	1	1	$ 336.83	$ 449.10	11/30/2018	BLUFF	84512
EVUT_251271	EV Level 2 Charger (single port)	2	2	$ 733.50	$ 978.00	12/5/2018	SALT LAKE CITY	84105
EVUT_251393	EV Level 2 Charger (single port)	2	2	$ 750.00	$ 1,000.00	12/7/2018	MILLCREEK	84124
EVUT_253677	EV Level 2 Charger (single port)	2	2	$ 1,240.88	$ 1,654.50	12/18/2018	COTTONWOOD HEIGHTS	84121
EVUT_262599	EV Level 2 Charger (single port)	4	4	$ 1,347.00	$ 1,796.00	1/22/2019	SLC	84111
EVUT_262605	EV Level 2 Charger (single port)	2	2	$ 658.50	$ 878.00	1/23/2019	OREM	84058
EVUT_267045	EV Level 2 Charger (single port)	1	1	$ 329.25	$ 439.00	2/19/2019	MIDVALE	84047
EVUT_267931	EV Level 2 Charger (single port)	2	2	$ 658.50	$ 878.00	3/13/2019	Hill Air Force Base	84056
EVUT_268257	EV Level 2 Charger (single port)	6	6	$ 2,020.95	$ 2,694.60	3/18/2019	SALT LAKE CITY	84111
EVUT_268687	EV Level 2 Charger (single port)	10	10	$ 3,368.25	$ 4,491.00	3/19/2019	Salt Lake City	84105
EVUT_269190	EV Level 2 Charger (single port)	1	1	$ 573.06	$ 764.08	3/27/2019	SUMMIT COUNTY	84098
EVUT_271416	EV Level 2 Charger (single port)	4	4	$ 1,317.30	$ 1,756.40	4/8/2019	SALT LAKE CITY	84102
EVUT_272507	EV Level 2 Charger (single port)	2	2	$ 673.65	$ 898.20	4/12/2019	LAKE POINT	84074
EVUT_272508	EV Level 2 Charger (single port)	1	1	$ 412.49	$ 549.99	4/12/2019	MILLCREEK	84109
EVUT_276557	EV Level 2 Charger (single port)	2	2	$ 868.05	$ 1,157.40	5/14/2019	SALT LAKE CITY	84116
EVUT_277484	EV Level 2 Charger (single port)	4	4	$ 1,347.30	$ 1,796.40	5/16/2019	SALT LAKE CITY	84101
EVUT_277864	EV Level 2 Charger (single port)	1	1	$ 303.75	$ 405.00	5/21/2019	OREM	84058
EVUT_277936	EV Level 2 Charger (single port)	6	6	$ 2,604.15	$ 3,472.20	5/23/2019	SALT LAKE CITY	84102
EVUT_278370	EV Level 2 Charger (single port)	1	1	$ 444.75	$ 593.00	6/4/2019	SOUTH SALT LAKE	84115
EVUT_278371	EV Level 2 Charger (single port)	1	1	$ 444.75	$ 593.00	6/4/2019	SANDY	84070
EVUT_278376	EV Level 2 Charger (single port)	2	2	$ 673.65	$ 898.20	6/4/2019	DRAPER	84020
EVUT_278375	EV Level 2 Charger (single port)	1	1	$ 476.25	$ 635.00	6/4/2019	LIBERTY	84310
EVUT_278375	EV Level 2 Charger (single port)	1	1	$ 498.75	$ 665.00	6/4/2019	LIBERTY	84310
EVUT_279492	EV Level 2 Charger (single port)	1	1	$ 673.65	$ 898.20	6/11/2019	TAYLORSVILLE	84129
EVUT_279494	EV Level 2 Charger (single port)	4	4	$ 1,525.50	$ 2,034.00	6/11/2019	SALT LAKE CITY	84105
EVUT_280008	EV Level 2 Charger (single port)	1	1	$ 375.00	$ 500.00	6/21/2019	SOUTH SALT LAKE	84115
EVUT_281145	EV Level 2 Charger (single port)	2	2	$ 1,334.91	$ 1,779.88	7/3/2019	TREMONTON	84337
EVUT_281147	EV Level 2 Charger (single port)	4	4	$ 2,994.10	$ 3,992.13	7/3/2019	CENTERVILLE	84014
EVUT_281411	EV Level 2 Charger (single port)	1	1	$ 381.38	$ 508.50	7/9/2019	SOUTH SALT LAKE	84119
EVUT_282408	EV Level 2 Charger (single port)	1	1	$ 561.75	$ 749.00	7/29/2019	OREM	84057
EVUT_283198	EV Level 2 Charger (single port)	4	4	$ 1,525.50	$ 2,034.00	7/29/2019	SALT LAKE CITY	84116
EVUT_283443	EV Level 2 Charger (single port)	6	6	$ 2,020.95	$ 2,694.60	8/1/2019	SALT LAKE CITY	84180
EVUT_283879	EV Level 2 Charger (single port)	8	8	$ 3,051.00	$ 4,068.00	8/9/2019	SALT LAKE CITY	84111
EVUT_284277	EV Level 2 Charger (single port)	1	1	$ 375.00	$ 500.00	8/14/2019	WEST VALLEY CITY	84120
EVUT_285967	EV Level 2 Charger (single port)	9	9	$ 20,182.50	$ 26,910.00	8/26/2019	COTTONWOOD HEIGHTS	84121
EVUT_285974	EV Level 2 Charger (single port)	4	4	$ 8,970.00	$ 11,960.00	8/26/2019	COTTONWOOD HEIGHTS	84121
EVUT_285976	EV Level 2 Charger (single port)	1	1	$ 1,950.00	$ 2,600.00	8/26/2019	MIDVALE	84047

Project Name	Measure_Name	Quantity	Number of Ports	Customer Incentive	Measure Cost	Creation Date	City	Zip Code
EVUT_286376	EV Level 2 Charger (single port)	1	1	$ 381.38	$ 508.50	9/3/2019	ALTA	84092
EVUT_288404	EV Level 2 Charger (single port)	2	2	$ 1,971.00	$ 2,628.00	9/24/2019	TREMONTON	84337
N/A	EV Time of Use Load Research Study	81	-	$ 17,000.00	-	Q4 2018 - Q3 2019	N/A	
EVUT_243844	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	10/16/2018	BLUFFDALE	84065
EVUT_244027	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	10/16/2018	HERRIMAN	84096
EVUT_244408	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	10/23/2018	MAPLETON	84664
EVUT_258968	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	12/26/2018	RIVERTON	84065
EVUT_259445	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	1/2/2019	SANDY	84070
EVUT_259662	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	1/7/2019	HIGHLAND	84003
EVUT_260081	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	1/10/2019	NIBLEY	84321
EVUT_260098	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	1/14/2019	HERRIMAN	84096
EVUT_263685	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	1/31/2019	WEST JORDAN	84088
EVUT_265369	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	2/1/2019	VINEYARD	84059
EVUT_266480	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	2/8/2019	DRAPER	84020
EVUT_266485	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	2/11/2019	MILLCREEK	84124
EVUT_266486	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	2/11/2019	RIVERTON	84096
EVUT_267225	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	2/25/2019	FARMINGTON	84025
EVUT_267218	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	2/25/2019	FARMINGTON	84025
EVUT_267508	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	2/28/2019	HIGHLAND	84003
EVUT_267238	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	3/1/2019	PARK CITY	84098
EVUT_268051	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	3/14/2019	NORTH SALT LAKE	84054
EVUT_269183	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	3/26/2019	TAYLORSVILLE	84129
EVUT_269186	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	3/28/2019	MILLCREEK	84109
EVUT_271328	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	4/4/2019	WHITE CITY	84094
EVUT_272503	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	4/16/2019	MILLCREEK	84106
EVUT_272872	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	4/22/2019	WEST JORDAN	84081
EVUT_273040	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	4/25/2019	SALT LAKE CITY	84108
EVUT_273043	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	4/26/2019	HERRIMAN	84096
EVUT_273048	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	4/29/2019	PLAIN CITY	84404
EVUT_273050	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	4/29/2019	MILLCREEK	84124
EVUT_273692	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	5/1/2019	TAYLORSVILLE	84129
EVUT_275861	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	5/1/2019	FRANCIS	84036
EVUT_277996	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	5/29/2019	TOOELE	84074
EVUT_281136	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	7/1/2019	STANSBURY PARK	84074
EVUT_282701	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	7/26/2019	SOUTH SALT LAKE	84106
EVUT_282702	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	7/26/2019	ERDA	84074
EVUT_282910	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	7/26/2019	OGDEN	84403
EVUT_283346	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	8/1/2019	BLUFFDALE	84065
EVUT_283442	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	8/1/2019	MILLCREEK	84109
EVUT_283462	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	8/5/2019	WEST BOUNTIFUL	84087
EVUT_284466	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	8/20/2019	SYRACUSE	84075
EVUT_284877	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	1	-	$ 200.00	-	8/23/2019	SALT LAKE CITY	84106
EVUT_243210	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	10/1/2018	PARK CITY	84098
EVUT_243211	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	10/1/2018	HERRIMAN	84096
EVUT_243569	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	10/4/2018	AMERICAN FORK	84003
EVUT_243696	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	10/16/2018	SALT LAKE CITY	84103
EVUT_243701	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	10/16/2018	WEST VALLEY CITY	84119
EVUT_243702	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	10/16/2018	SALT LAKE CITY	84105
EVUT_243843	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	10/16/2018	OREM	84097

Project Name	Measure_Name	Quantity	Number of Ports	Customer Incentive	Measure Cost	Creation Date	City	Zip Code
EVUT_243850	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	10/16/2018	KAYSVILLE	84037
EVUT_243851	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	10/16/2018	SOUTH JORDAN	84009
EVUT_243857	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	10/16/2018	HERRIMAN	84096
EVUT_244048	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	10/16/2018	WEST VALLEY CITY	84120
EVUT_244166	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	10/16/2018	MILLCREEK	84124
EVUT_244367	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	10/19/2018	MILLCREEK	84124
EVUT_244405	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	10/23/2018	VINEYARD	84059
EVUT_244857	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	10/30/2018	SANDY	84070
EVUT_245001	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	11/1/2018	WEST JORDAN	84081
EVUT_248410	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	11/6/2018	LAYTON	84041
EVUT_250502	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	11/27/2018	STANSBURY PARK	84074
EVUT_250606	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	11/27/2018	TOQUERVILLE	84774
EVUT_250802	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	11/29/2018	FARMINGTON	84025
EVUT_250803	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	11/29/2018	OREM	84057
EVUT_251231	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	12/5/2018	PARK CITY	84098
EVUT_251398	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	12/12/2018	WEST JORDAN	84088
EVUT_251998	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	12/12/2018	SALT LAKE CITY	84103
EVUT_251397	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	12/13/2018	WEST VALLEY CITY	84119
EVUT_252141	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	12/13/2018	GRANTSVILLE	84029
EVUT_258963	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	12/26/2018	BLUFFDALE	84065
EVUT_258964	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	12/26/2018	CEDAR HILLS	84062
EVUT_259524	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	1/4/2019	WEST VALLEY CITY	84119
EVUT_259651	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	1/4/2019	TAYLORSVILLE	84129
EVUT_259661	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	1/7/2019	ERDA	84074
EVUT_259664	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	1/8/2019	HERRIMAN	84096
EVUT_260082	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	1/10/2019	DRAPER	84020
EVUT_262833	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	1/25/2019	NORTH OGDEN	84414
EVUT_262840	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	1/25/2019	SANDY	84092
EVUT_262846	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	1/28/2019	HARRISVILLE	84414
EVUT_262847	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	1/28/2019	MILLCREEK	84124
EVUT_262848	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	1/28/2019	WELLSVILLE	84339
EVUT_263686	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	1/31/2019	SALT LAKE CITY	84109
EVUT_264537	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	2/1/2019	LIBERTY	84310
EVUT_265378	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	2/5/2019	SARATOGA SPRINGS	84045
EVUT_265372	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	2/5/2019	MILLCREEK	84124
EVUT_266321	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	2/6/2019	DRAPER	84020
EVUT_266479	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	2/8/2019	DRAPER	84020
EVUT_266482	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	2/8/2019	NORTH OGDEN	84414
EVUT_266671	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	2/12/2019	SOUTH JORDAN	84009
EVUT_266741	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	2/14/2019	MILLCREEK	84124
EVUT_267235	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	2/25/2019	COTTONWOOD HEIGHTS	84121
EVUT_267239	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	2/25/2019	SALT LAKE CITY	84105
EVUT_267509	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	3/1/2019	SANDY	84093
EVUT_267530	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	3/1/2019	DRAPER	84020
EVUT_267808	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	3/12/2019	FARMINGTON	84025
EVUT_267821	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	3/12/2019	VERNAL	84078
EVUT_267930	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	3/13/2019	SOUTH SALT LAKE	84115
EVUT_268102	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	3/14/2019	MILLCREEK	84109
EVUT_268682	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	3/19/2019	SYRACUSE	84075

Project Name	Measure_Name	Quantity	Number of Ports	Customer Incentive	Measure Cost	Creation Date	City	Zip Code
EVUT_268692	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	3/20/2019	NORTH OGDEN	84414
EVUT_269185	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	3/27/2019	OGDEN	84404
EVUT_271326	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	4/3/2019	FARMINGTON	84025
EVUT_271417	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	4/9/2019	LAYTON	84041
EVUT_272504	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	4/16/2019	NEW HARMONY	84757
EVUT_272869	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	4/19/2019	DRAPER	84020
EVUT_272873	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	4/22/2019	NORTH LOGAN	84341
EVUT_272874	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	4/23/2019	RIVERTON	84096
EVUT_272875	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	4/23/2019	WEST HAVEN	84401
EVUT_273049	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	4/29/2019	SANDY	84092
EVUT_273051	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	4/29/2019	AMERICAN FORK	84003
EVUT_275862	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	5/1/2019	GRANTSVILLE	84029
EVUT_276006	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	5/6/2019	LAYTON	84041
EVUT_276007	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	5/6/2019	LAYTON	84040
EVUT_276501	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	5/13/2019	DRAPER	84020
EVUT_278365	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	6/4/2019	SALT LAKE CITY	84108
EVUT_278383	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	6/11/2019	WEST BOUNTIFUL	84087
EVUT_278451	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	6/11/2019	OGDEN	84403
EVUT_278452	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	6/11/2019	MURRAY	84121
EVUT_278453	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	6/11/2019	FARR WEST	84404
EVUT_278454	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	6/11/2019	HOLLADAY	84121
EVUT_278458	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	6/11/2019	OGDEN	84403
EVUT_279490	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	6/11/2019	LAYTON	84041
EVUT_279632	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	6/18/2019	HERRIMAN	84096
EVUT_280189	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	6/25/2019	MARRIOTT SLATERVILLE	84404
EVUT_280695	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	7/1/2019	PARK CITY	84060
EVUT_281409	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	7/9/2019	NORTH SALT LAKE	84054
EVUT_281503	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	7/11/2019	SOUTH SALT LAKE	84115
EVUT_282529	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	7/23/2019	TAYLORSVILLE	84123
EVUT_282539	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	7/23/2019	MILLCREEK	84106
EVUT_282696	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	7/23/2019	DRAPER	84020
EVUT_282717	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	7/26/2019	LAYTON	84041
EVUT_282902	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	7/26/2019	SALT LAKE CITY	84105
EVUT_283196	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	7/29/2019	MILLCREEK	84109
EVUT_283459	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	8/2/2019	NIBLEY	84321
EVUT_283461	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	8/5/2019	HERRIMAN	84096
EVUT_282540	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	8/13/2019	SALT LAKE CITY	84105
EVUT_284271	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	8/14/2019	LAYTON	84040
EVUT_284398	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	8/16/2019	DRAPER	84020
EVUT_285079	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	8/23/2019	CEDAR FORT	84013
EVUT_285832	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	8/26/2019	WOODS CROSS	84087
EVUT_285833	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	8/26/2019	TREMONTON	84337
EVUT_286329	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	8/29/2019	PARK CITY	84098
EVUT_286371	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	9/3/2019	CEDAR CITY	84721
EVUT_286725	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	9/6/2019	TAYLORSVILLE	84123
EVUT_286726	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	9/6/2019	STANSBURY PARK	84074
EVUT_286964	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	9/11/2019	OGDEN	84404
EVUT_287252	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	9/16/2019	ROY	84067
EVUT_287627	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	9/18/2019	HERRIMAN	84096

Project Name	Measure_Name	Quantity	Number of Ports	Customer Incentive	Measure Cost	Creation Date	City	Zip Code
EVUT_287628	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	9/18/2019	SANDY	84092
EVUT_288208	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	9/19/2019	SALT LAKE CITY	84108
EVUT_288221	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	1	-	$ 200.00	-	9/23/2019	NORTH LOGAN	84341
				$ 940,532.49				

Sub-Totals	EV Time of Use Rate option 1 - off peak 7 cents, on peak 22 cents	$ 8,200.00
	EV Time of Use Rate option 2 - off peak 3 cents, on peak 34 cents	$ 21,200.00
	EV Time of Use Load Research Study	$ 17,000.00
	Non-Residential AC Level 2 Charger Single Port Incentive Payments	$ 108,013.58
	Non-Residential AC Level 2 Charger Multi-Port Incentive Payments	$ 520,440.58
	Non-Residential & Multi-Family DC Fast Charger Incentive Payments	$ 265,678.33
Grand Total		**$ 940,532.49**

*Includes 2019 EV fiscal year budget incentive payments (October 1, 2018 - September 30, 2019)

Exhibit 2-B

EV Program Custom Project Committed Funds and Expenditures

EV Program Budget Custom Project Expenditures

Year Committed	Custom Projects	Committed Funds	Year Completed	$ Paid	$ Variance
2017	Project 1	$ 250,000	2018	$ 250,000	$ -
	Project 2	$ 8,000	2019	$ 7,998	$ (2)
	Project 3	$ 470,000	2018	$ 456,441	$ (13,559)
	Project 4	$ 153,000		$ 153,000	$ -
	Project 5	$ 237,500	2020	$ 237,500	$ -
	Project 6	$ 50,000	2018	$ 50,000	$ -
	Project 7	$ 57,005		$ 56,963	$ (42)
	Project 8	$ 69,369		$ 69,369	$ -
	Project 9	$ 65,000		$ 58,047	$ (6,953)
	Total	**$ 1,359,874**		**$ 1,339,318**	**$ (20,556)**
2018	Project 10	$ 308,000	2019	$ 308,000	$ -
	Project 11	$ 70,000		$ 70,000	$ -
	Project 12	$ 120,500		$ 120,500	$ -
	Project 13	$ 500,000	TBD	$ -	$ -
	Total	**$ 998,500**		**$ 498,500**	**$ -**
2019	Project 14	$ 330,000	TBD	$ -	$ -
	Project 15	$ 170,000	TBD	$ -	$ -
	Project 16	$ 169,439.49	TBD	$ -	$ -
	Total	**$ 669,439.49**		**$ -**	**$ -**

Exhibit 2-C

EV Program Custom Project Details Year Over Year

Custom EV Projects Year over Year Committed vs. Completed

Committed Information					Completed Information			
Year Committed	Project #	Description	Equipment type	Incentive	Year Completed	Description	Equipment type	Incentive
2017	Project 1	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	$ 250,000	2018	No change from committed.	No change from committed.	$ 250,000
2017	Project 2	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)	$ 8,000	2019	No change from committed.	No change from committed.	$ 7,998.00
2017	Project 3	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 port)	$ 470,000	2018	Acutal project costs were less than intial estimates, resulting in a lower incentive payment.	No change from committed.	$ 456,441
2017	Project 4	This project aims to provide electric vehicle charging for the public and employees at a prominent location in down town Salt Lake City by installing 12 AC Level 2 dual port charging stations, and infrastructure for seven future stations.	12 AC Level 2 Chargers (multi-port)	$ 153,000	2018	No change from committed.	No change from committed.	$ 153,000
2017	Project 5	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	18 AC Level 2 Chargers & 1 DC Fast Charger (multi-port)	$ 237,500	2020	No change from committed.	No change from committed.	$ 237,500
2017	Project 6	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 market penetration of PEVs and hybrids. Installed on city property for public use.	2 AC Level 2 Chargers and 1 DC Fast Charger (single port)	$ 50,000	2018	No change from committed.	No change from committed.	$ 50,000
2017	Project 7	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 (multi-port)	$ 57,005	2018	Acutal project costs were less than intial estimates, resulting in a lower incentive payment.	No change from committed.	$ 56,963
2017	Project 8	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 (multi-port)	$ 69,369	2018	No change from committed.	No change from committed.	$ 69,369
2017	Project 9	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 (multi-port)	$ 65,000	2018	Minor change in project scope	AC Level 2 charger was not installed	$ 58,047
2018	Project 10	A major City will be installing a city-wide system of EV equipment for residents, guests, travelers, and ride-share drivers. The City is in a key strategic position to embark on such a wide-ranging project. The City is centrally located in the Wasatch Front and has notable popular attractions within its borders which attract a considerable amount of vehicles. The city experiences significant air pollution during bad inversion events in the winter and ozone buildup in the summer. To mitigate these effects, the city believes that by providing EV equipment on a city-wide scale, residents will be encouraged to adopt zero-emissions vehicles as a way to improve air quality.	44 AC Level 2 Charging Ports and 2 DC Fast Charging Ports	$ 308,000	2019	No change from committed.	No change from committed.	$308,000
2018	Project 11	A City is in the final stages of completing a new 130,000 sq-ft Public Works facility. The City has been evaluating and preparing to transition to electric fleet vehicles and is preparing to install charging stations at the new facility to service residents, employees, and fleet vehicles.	6 AC Level 2 Charging Ports and 1 DC Fast Charging Port	$ 70,000	2019	No change from committed.	No change from committed.	$70,000
2018	Project 12	A County is committed to leading sustainability actions that balance their fiduciary responsibility to taxpayers with stewardship of our extraordinary natural surroundings, while aligning with partners who have common goals to serve the public. This custom project provides an opportunity for the County and Rocky Mountain Power to partner together in service to residents, local governments, and businesses by expanding the EV charging infrastructure in the County. A DC Fast charger was selected for installation in to fill the gap in charging stations along the east-west Interstate 80 corridor. Level 2 chargers were selected for their lower cost and ease of installation to serve the County fleet as well as residents. This project will provide EV charging infrastructure in the County where little, if any, EV charging exists. In so doing, the County and other municipal governments will be able to deploy more EVs that eliminate tailpipe emissions and lower annual operating costs; provide charging for County employees as well as residents, and set an example for other businesses to provide charging stations.	12 AC Level 2 Charging Ports and 1 DC Fast Charger Port	$ 120,500	2019	No change from committed.	No change from committed.	$120,500
2018	Project 13	A public transit group will be transitioning to electric buses. The chargers will be used for on-route use and battery charging while parked in bus depots.	Two 500 kW Electric Bus Chargers and 5 DC Fast Charging Ports	$ 500,000	Pending			

Exhibit 2-D

EV Program Actual SAP Postings by Calendar Year

Actual SAP Postings by Calendar Year for EV Program

EV Program Actual Postings in SAP by Calendar Year						
Cost Category	**CY 2017**	**CY 2018***	**CY 2019**	**CY 2020**	**CY 2021**	**TOTAL**
Time of Use Rate Sign-up	$ 6,800	$ 24,000	$ 28,600.00			**$ 59,400**
Time of Use Load Research Study Participation		$ 10,000	$ 17,000.00			**$ 27,000**
Time of Use Meters	$ -	$ 79,394	$ 554.48			**$ 79,948**
Non-Residential AC Level 2 Chargers – Single Port	$ 116,157	$ 109,990	$ 108,565.43			**$ 334,713**
Non-Residential AC Level 2 Chargers – Multi-Port		$ 180,716	$ 507,769.60			**$ 688,486**
Non-Residential & Multi-Family DC Fast Chargers	$ 54,618	$ 97,878	$ 265,678.33			**$ 418,174**
Custom Projects	$ -	$ 1,093,820	$ 506,497.68			**$ 1,600,318**
Administration	$ 176,176	$ 176,427	$ 127,958.88			**$ 480,562**
Outreach & Awareness	$ 133,751	$ 109,479	$ 261,514.66			**$ 504,744**
Total	**$ 487,502**	**$ 1,881,703**	**$ 1,824,139.06**			**$ 4,193,344**

* Includes transferred (OMAG) costs of program expenditures prior to Commision approval in July 2017.

Exhibit 2-E

EV Program Budget Allocations Year Over Year

EV Program Budget Costs / Committed Funds by Year

	2017 EV Budget Costs / Committed Funds			2018 EV Budget Costs / Committed Funds			2019 EV Budget Costs / Committed Funds		
	Prescriptive Incentives Completed Q3 2017	Custom Incentives Committed Q3 - Q4 2017	Total 2017	Prescriptive Incentives Completed Q4 2017 - Q3 2018	Custom Incentives Committed Q1 - Q4 2018	Total 2018	Prescriptive Incentives Completed Q4 2018 - Q3 2019	Custom Incentives Committed Q1 - Q4 2019	Total 2019
TOU Incentives	$ 2,800		$ 2,800	$ 22,400		$ 22,400	$ 29,400		$ 29,400
TOU Load Research Incentives				$ 10,000		$ 10,000	$ 17,000		$ 17,000
TOU Meters						$ 79,394			$ 554.48
AC Level 2 Incentives (Single Port)	$ 65,309		$ 65,309	$ 102,907		$ 102,907	$ 108,013.58		$ 108,013.58
AC Level 2 Incentives (Multiple Port)				$ 189,844		$ 189,844	$ 520,440.58		$ 520,440.58
DC Fast Charger Incentives	$ 54,618		$ 54,618	$ 97,878		$ 97,878	$ 265,678.33		$ 265,678.33
Custom Project Incentives		$ 1,359,874	$ 1,359,874		$ 998,500	$ 998,500		$ 669,439.49	$ 669,439.49
Administration			$ 176,176			$ 175,427			$ 127,958.88
Outreach & Awareness			$ 133,751			$ 109,479			$ 261,514.66
		Total	**$ 1,792,528**		**Total**	**$ 1,785,828**		**Total**	**$ 2,000,000**

TOTAL ALLOCATED BUDGET FOR ALL YEARS $ 5,578,356

STEP Project Report

Period Ended: December 31, 2019

STEP Project Name: Co-firing Tests of Woody-waste (biomass) Materials in Hunter Unit 3

Project Objective:

This project consists of two 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, with coal making up the remaining 90%. The processed woody waste will consist of wood resources including scrap and waste material from logging operations and wood processing plants. A torrified product and a steam exploded product are the two types of processed woody waste that will be tested. The primary objective of these tests will be to determine whether these processed biomass fuels can be effectively 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. These tests will also be used as a mechanism to further evaluate and demonstrate these processed woody waste technologies. The consultants responsible for planning, conducting, and reporting the results of the tests are engineering professors from the University of Utah's Combustion Laboratory and from Brigham Young University.

In Docket No. 16-035-36, the Commission approved the Company's request to increase funding for the Co-Fired Woody Waste project by $748,980, utilizing funds from the canceled Alternative NOx project. With these additional funds, the Company expanded the scope to substantially increase the amount of processed biomass material from both woody waste providers to extend the number of hours in the test burn and to increase the measurements taken during the test to gain a better understanding of boiler operation during the co-firing.

Project Update:

Amaron provided 724 tons of torrified biomass material to the Hunter Plant. The test burn of the torrified material was conducted in Unit 3 of the Hunter Plant on August 22 and August 23 of 2019 and the consultants gave a review of preliminary results of the torrified test burn on December 5, 2019. The test used a blend of 20% biomass material and 80% coal over a period of 12 hours. The biomass fuel performed as planned in the test and produced lower concentrations of NO_x and SO_2 as expected.

AEG, the supplier of steam exploded biomass material, has moved their production facility to North Carolina. PacifiCorp and AEG are currently re-negotiating the supply contract and delivery schedule for the steam exploded biomass material. Once an agreement is reached with AEG, the test burn of the steam exploded material is expected to occur in the second half of 2020.

Project Accounting:

	2017	2018	2019	Total
Annual Collection (Budget)	$0.00	$177,032	$515,668	$692,700
Annual Spend	$0.00	$262,837*	$588,943	$851,780
Committed Funds	$0.00	$0.00	$0.00	$0.00
Uncommitted Funds	$0.00	$0.00	$0.00	$0.00
External OMAG Expenses	$0.00	$0.00	$0.00	$0.00
Subtotal	$0.00	$262,837	$588,943	$851,780

*The 2018 STEP report reported total spend for 2018 as $230,277. However, there was a $32,560 feedstock payment to AEG that was that was made in 2018, but not included in the 2018 STEP report because there was a 2 month period when this payment was backed out of the Company's accounting records and then reposted.

Project Milestones:

Project Milestones	Delivery Date	Status/Progress
Contracts with PacifiCorp complete	UofU – June 27, 2017 Amaron – February 14, 2018 AEG – March 2, 2018	Complete Complete Complete
Select biomass fuel source	December 1, 2017	Complete
Process first ton of biomass material	Amaron – March 9, 2018	Amaron – Complete
Sign new Amaron supply agreement	May 31, 2019	Complete
Revise schedule for expanded Amaron test burn	July 1, 2019	Complete
All Amaron biomass material delivered to the Hunter plant	August 15, 2019	Complete
Finalize Amaron test burn plan and operating procedures	August 15, 2019	Complete
Test burn monitoring equipment installation complete	August 15, 2019	Complete

Amaron test burn conducted	August 31, 2019	Complete
Sign updated AEG supply agreement	April 30, 2020	On Schedule
Schedule expanded AEG test burn	To be determined	
All AEG biomass material delivered to the Hunter plant	To be determined	
Finalize AEG test burn plan and operating procedures	To be determined	
Test burn monitoring equipment installation complete	To be determined	
AEG test burn conducted	To be determined	
Final report completed	To Be Determined Once Revised Schedule is Completed	

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.	Amaron is using Woodscapes as their biomass supplier.	
Secure supply agreement with AEG	Project will be supplied from a processing facility in the eastern US rather than Utah.	The Company is working on agreement and schedule from AEG.		
Design the test burn and monitoring plan	University of Utah is developing the project plan.	The test burn and monitoring plan is being updated in response to the project expansion approval.	The test burn of the Amaron product went smoothly and the preliminary results align with the pre-test expectations	
Address any plant operation or air permit concerns	Worked with Jim Doak to notify the State of Utah about the project.	The relatively small quantities of biomass material do not impact the air permit.		

Program Benefits:

If successful, the project will 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 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. If the test proves successful, it could be a used in future initiatives to improve forest health and clean air.

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, 2019

STEP Program Name: Huntington Plant Neural Network Optimization Project (NOx Neural Network Implementation) COMPLETE

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 is designed to 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. Combustion optimization targets nitrogen oxides ("NO_X") for improved emissions and carbon monoxide ("CO") for improved emissions and unit efficiency. Once the combustion control phase is 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:

	2017	2018	2019	Total
Annual Collection (Budget)	$547,807	$178,924	$216,718	$943,449
Annual Spend	$457,767	$207,616	$231,621	$897,006
Committed Funds	$0.00	$0.00	$0.00	$0.00
Uncommitted Funds	$0.00	$0.00	$0.00	$0.00
External OMAG Expenses	$0.00	$0.00	$0.00	$0.00
Subtotal	$457,767	$207,616	$231,621	$897,006

Program Milestones:

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	Complete
Parametric study on optimization of auxiliary systems complete	August 31, 2018	Cooling Tower Data being analyzed site visit by U of U completed
Annual progress report complete for Year 2	March 31, 2019	Complete
Cooling Tower control systems	June 30, 2019	Complete December 31, 2019 and ongoing.
Exploratory study on dynamic optimization with set point ramping complete	August 31, 2019	Focused on Cooling Tower Optimization
Final study on impact on emissions complete U of U	December 31, 2019	Complete March 11, 2020

Key Program Findings/ Challenges / Lessons Learned:

Challenges	Results/Progress
a. Communications between the Neural Network Server and the Distributed Control System	Problems with process control technology have been identified and resolved. Changed communication protocol to Modbus to prevent further issues in the future. – Complete
b. Supplied Basic Optimization component of software incomplete	Building new optimization algorithm as interim solution. Griffin optimizer is been refined. – Complete
c. Reducing NO_x	Continued model tuning and using predictor at near full load operations is showing positive reduction of NO_X. As seen below of about 9.6%. – Ongoing

d. Reducing CO and unburned coal improvement.	The initial indication for CO reduction is very positive. Initially seen a large improvement with over 50% reduction in CO. – Ongoing
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. Added some rules to minimize this with good results. – Complete
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. – Tuning ongoing and new lows being tried, down to 15% load.
g. FGD control systems	Not started at this time. Changed to Cooling Tower Optimization with the variable frequency drive motors.
h. Cooling Tower Optimization	The cooling Tower Optimization activated August 27, 2019, and has been running since the unit overhaul. Some improvements have been noted. – Ongoing
i. Upgrading Neural Network Server for required Cyber Security controls	This has been a periodic issue when the unit had the DCS controls upgrade the communication between the DCS and the COS was broke temporarily and a new patch from Griffin solved this issue.
j. Unit Load Volatility	The unit load profile has shifted to amore of a short term dispatch mode which means larger and more frequent load changes. This creates additional challenges for optimization. – Ongoing
k. Lower Low Load Operation	With the necessity to get the unit load to as low as possible, the unit is not designed for optimized low load operation. However with learning this new area we are able to get the NO_x and CO lower than where it started. Still this is an area that needs work. – Ongoing

Program Progress and Benefits:

The Griffin system Neural Network is installed and operational. The Combustion Optimizations System ("COS") has been fully implemented on this unit with excellent results. The Company continues to learn while improving the data model and implementing output recommendations. Challenges included windbox pressure excursions, and high reheat tube metal temperatures. The solution to high tube temperatures involved a combination of soot blowing, increased O_2, and manipulation of SOFA tilts. The effort to control tube temperatures is counter to what is needed to control NO_X. Griffin uses a particle swarm optimizer to determine if one damper position is better than another. This should work 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.

It has been difficult to have the model numbers converge into a particular area for improvement. This has been addressed by adding more rules for how the control bias are used. These "Expert Rules" have been developed with the knowledge of the operators and combustion tuners. These rules then guide the COS for the control bias to get the resulting improvements. For 2019, the COS was running 67% of the time.

The sootblower control module Knowledgeable Soot Blowing ("KSB") has been installed and operational. This KSB is strictly an "Expert Rules" based system. The rules have also been developed with the significant input of the operators. The number of sootblower operations for the wall blowers has been reduced and seems to reasonably follow coal quality. As expected, when the coal quality deteriorates the operators tend to turn off the KSB.

The reduction in KSB up-time, translated to an improvement in heat rate, although the impact is difficult to quantify. The operators have accepted the KSB system with good results. For 2019, the KSB was on 66% of the time (73% during the first three quarters and only 15% during the last quarter due to overhaul and outages).

For tracking proposes, CO_2 has also been considered, as it is an indicator of Heat Rate. As CO_2 drops it is an indication of improved heat rate. Since the potential for CO_2 reductions was not identified in the original scope of this STEP project, no analysis of CO_2 has been done.

The results of this project are encouraging based on the 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 like loads during the given time period are compared, as can be seen in Chart 1. For comparison purposes, the consistent load range of 425-450 mw was chosen. This is 90 – 95% of full load. Since this three month baseline date was in the spring of 2017, loads were typically low. Looking at 2019 the load has shifted, more time at low load with the P-min at 70 MW and less time in the middle loads and more time at the upper loads. Even though the load profile of the unit has changed, the NO_X at all loads have been reduced through 2019.

	NO_X	*CO*	*CO2*	
Apr to Jun '17	**0.230**	**348**	**11.14%**	**Baseline Charts 1 & 3**
2018	0.199	126	10.47%	
2019	**0.208**	**115**	**9.06%**	**Charts 2 & 4**
% Reduction	9.6%	67.0%	18.67%	2019 vs baseline

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

In 2019, new system-wide demand really changed how the unit was operating and the load began to swing significantly throughout the day. This volatility of the unit creates new challenges for the COS in achieving low NO_X. The unit load average has come down with increased load variability. This variability can be measured with a Volatility Factor. The Volatility Factor in this case is the standard deviation over the previous five hours of the percent of load change compared to the previous five minutes. With the Volatility factor tracked it show correlation with NO_X and CO and does play a role in optimizing combustion. When at steady or near steady state combustion optimization works fairly easy but as the load changes and particularly as pulverizers need to come in or out of service to get the new load, this has a significant impact on optimization. This volatility factor for 2019 can be seen in Chart 5.

For 2019, Unit 2's load average was 311 MW, the NO_X average for all loads for the year was 0.185 #/mmbtu's, also seen in Chart 5. For comparison Chart 6 shows the average load for 2017 was 336 MW with an average NO_X of 0.209 #/mmbtu's. The load has been split more, with less time in the mid-range, higher at top and bottom load ranges. In the same Chart 6, for 2019 it shows what the NO_X was with the COS on and with the COS off. With the COS on the average NO_X reduction is 7% from 0.193 to 0.180 #/mmbtu's. The COS was on 60% of the time in 2019. (66% the first three quarters and only 12% the last quarter due to overhaul and outages)

Initially the Company hoped that the NO_X would be reduced 10–20%, which has been in line with the results. CO has seen remarkable improvements. With the continued support from the University of Utah and Griffin, the optimizer is being tweaked and will continue running in the foreseeable future. This project will continue for two more years ending December 2021. The University of Utah and Griffin will continue to be available to support the project as needed, to evaluate additional achievements and continue to monitor the status. This project continues to fund the Griffin license through 2021.

Potential future applications for similar projects:

With the positive result, the Company installed a similar Neural Network Optimization on Huntington Unit 1 and on Hunter Units 1 & 2.

Attachments:

Exhibit 4-A University of Utah Final Project Report STEP NOx Neural Network Project

Results/Appendix:

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

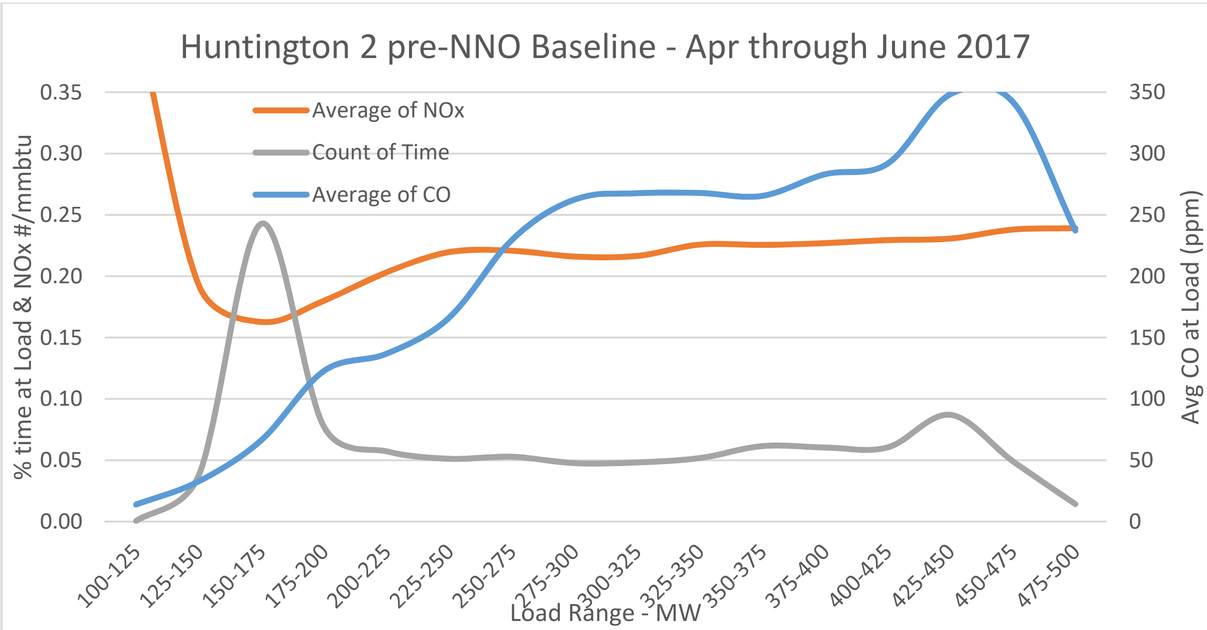

Chart 2 – NOx and CO versus load and percent of time at Load. 2019

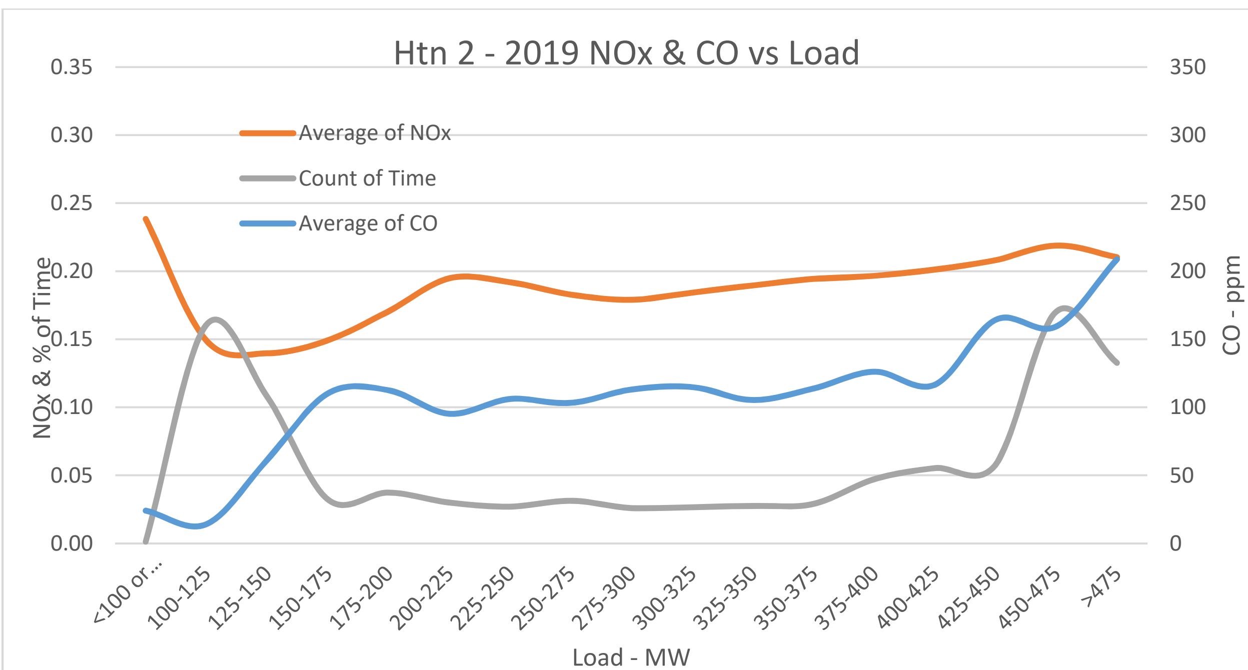

Chart 3 – Three Month data establishing baseline.

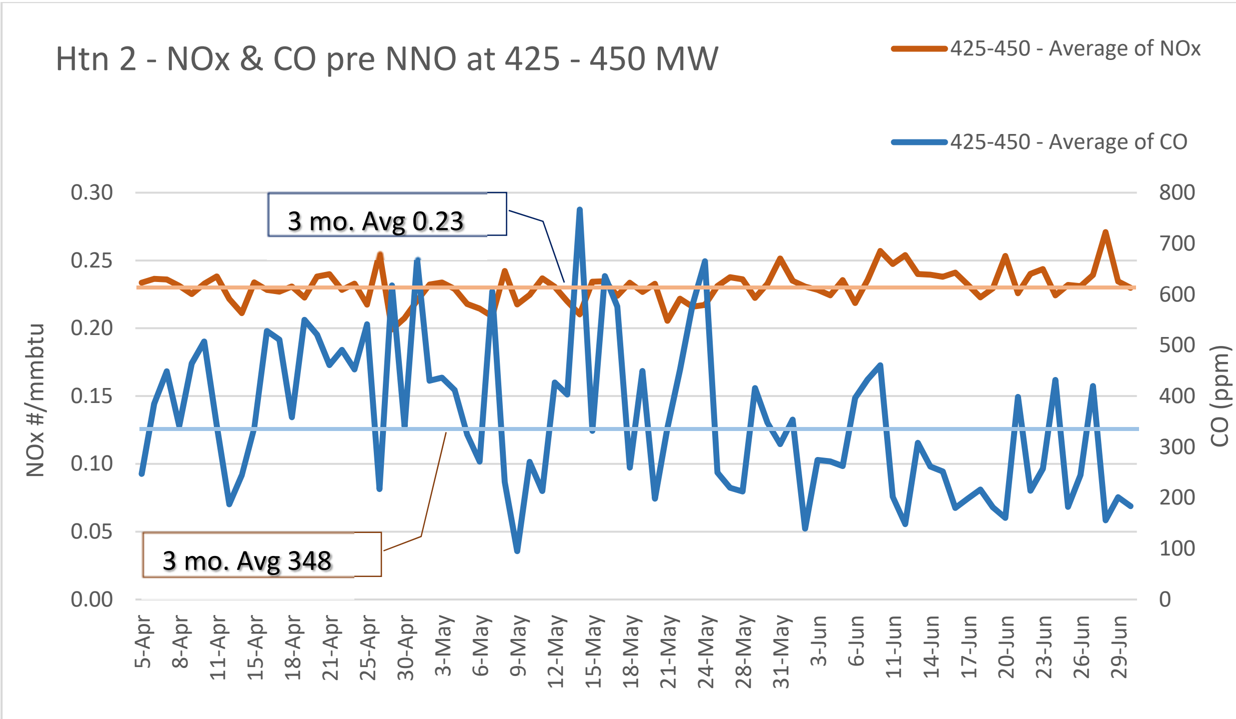

Chart 4 – Daily NOx & CO Average at comparison load

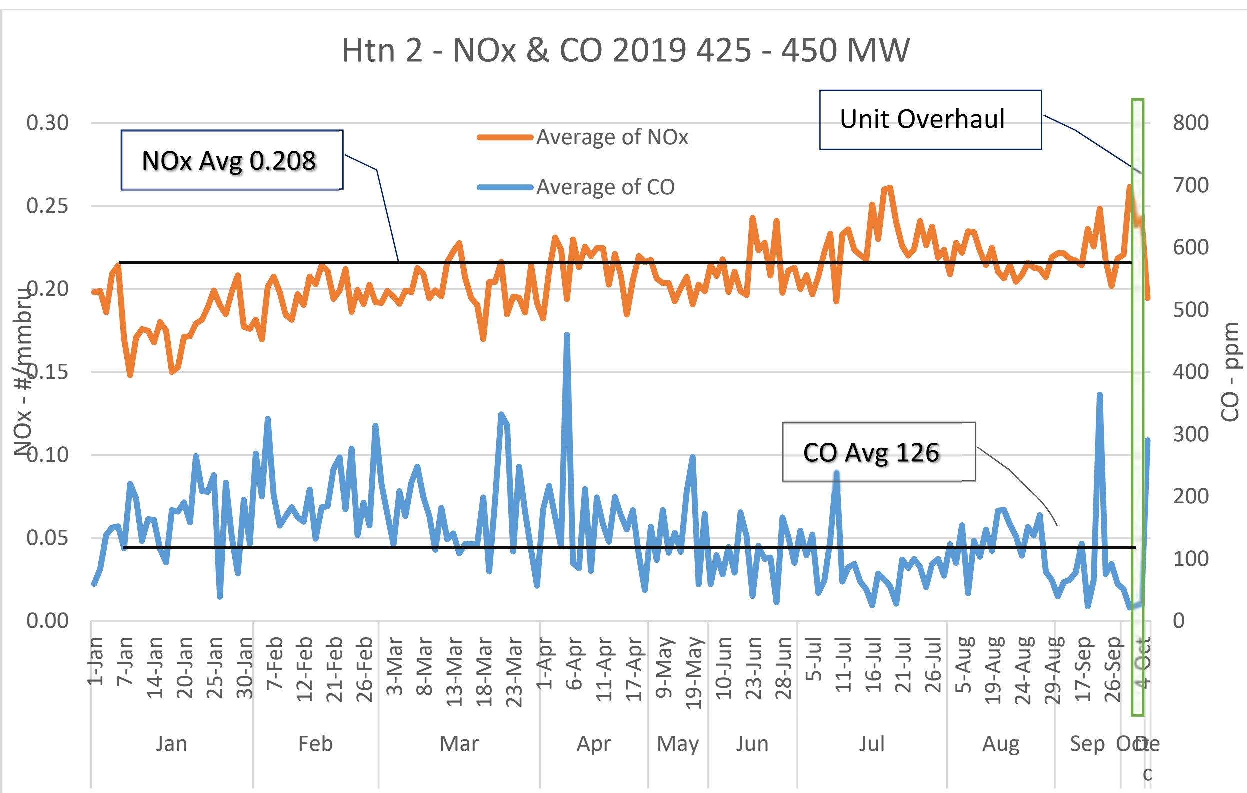

Chart 5 – 2019 Load, Volatility & NOx – Daily Average

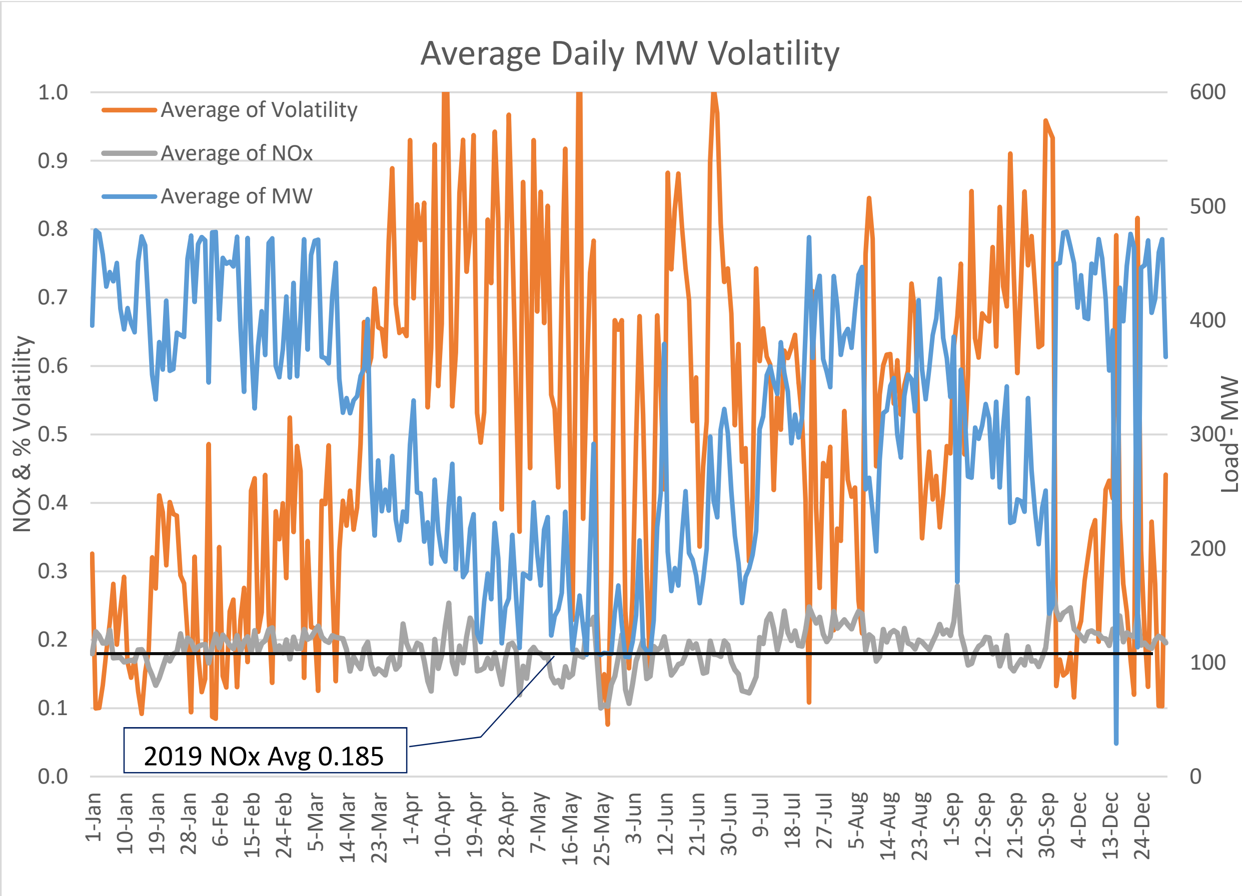

Chart 6 – COS On/Off Comparison and % of Time at unit load

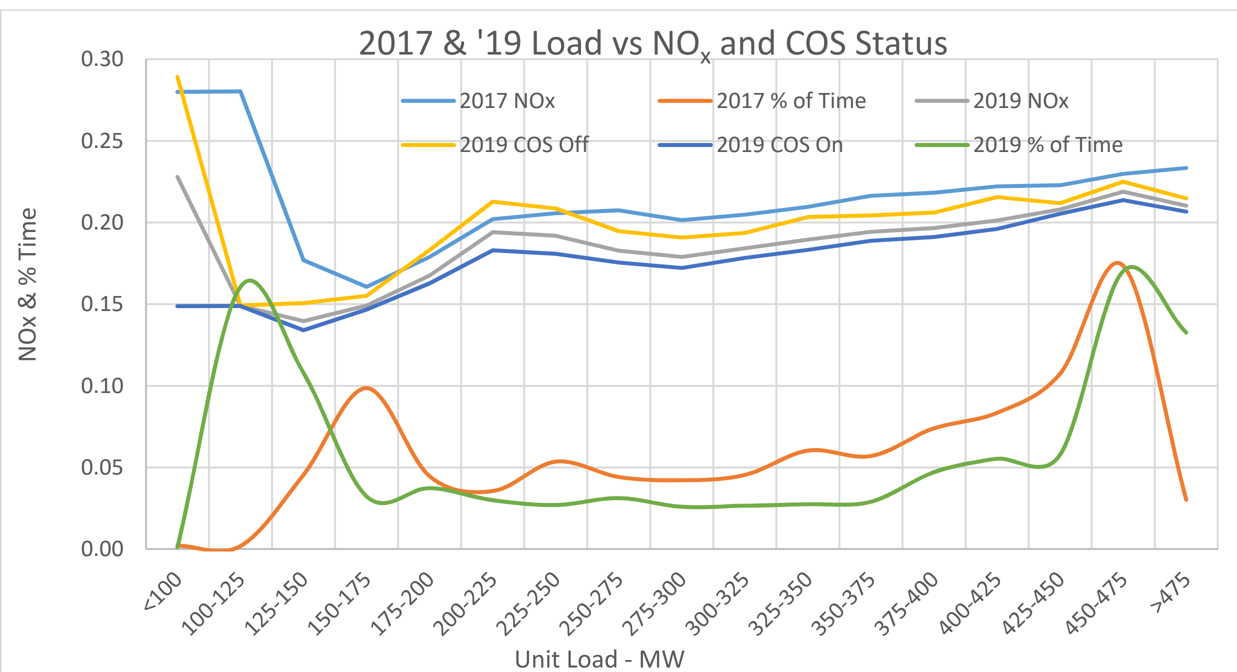

Exhibit 4-A

University of Utah Final Project Report STEP NOx Neural Network Project

DEPARTMENT OF Chemical Engineering
COLLEGE OF ENGINEERING | THE UNIVERSITY OF UTAH

University of Utah – U2 STEP NOx Neural Network Project

Final Project Report (January 2017 – December 2019)

Research Team Members – Dr. Kody Powell, Jake Tuttle, Landen Blackburn

Executive Summary:

The overall objective of the U2 STEP NOx Neural Network Project was to install, establish, and perform further research on the use of artificial neural networks to optimize coal combustion. The University of Utah (U of U) has been the primary research institution involved in this project and implemented control schemes and performed research on the unit's combustion process using the Griffin Open Systems Toolkit provided by Griffin Open Systems LLC. As the system was installed, brought online, and refined at PacifiCorp's Huntington Power Plant, Unit 2, important observations were made while working to achieve defined objectives of NOx reduction and overall system performance. The deliverable areas which the U of U focused on throughout the project along with quantifiable objectives worked toward are provided below. Results and observations associated with each area are summarized.

Overall, this project was able to realize large decreases in observed NOx emission rates across the unit's load range, and to make advancements in the application of artificial intelligence methods to other areas of the power plant with positive impacts. Although specific KPIs were not able to be achieved for NOx across the load range, the observed NOx reduction due to optimization using artificial intelligence models and methods was significant. Observations of unit performance and system developments to address other circumstances within the unit such as high temperatures benefitted day to day operation, contributing to greater flexibility of the station within the everchanging power market, and greatly helped increase adoption of the system by operators at the station.

University of Utah Deliverables & Objectives:

Parametric Study

Perform a parametric study of the test unit pre-installation, during installation, during learning phase, and after system has been brought online. Identify most effective control loops and input variables.

NOx emission rate (lbs/MMBtu) was the focus of this work, and identification of control methods and parameters which most affected its generation were evaluated throughout the project. Average NOx at each 10 MW increment of load was identified during the baseline period and each year of the project (2017, 2018, and 2019). The baseline period is defined as beginning with the unit's return from the last major unit overhaul prior to project beginning (August 2015) up to activation of the optimization system (September 2017). NOx emission rate profiles for each period are displayed in Figure 1.

The 2017 profile is very similar to the baseline, due in part to the baseline being partly comprised of 2017 data and also to the 2017 period seeing very little optimizer operation as the system was in its learning and major development phase. The 2018 and 2019 periods both display noticeable improvements on baseline and 2017 operation, with 2018 being the overall best, other than at minimum unit load. The unit experienced a large degree of hardware degradation during the 2019 period, contributing in large part to its observed overall decreased performance relative to 2018. For these yearly averages, the **2018 period displays a 15.2% improvement** on the baseline profile, and the **2019 period displays a 12.3% improvement**. Performance was analyzed quarterly during the project, which identified QIV 2018 as displaying the **greatest average NOx emission rate reduction of 22.5%** relative to the baseline period.

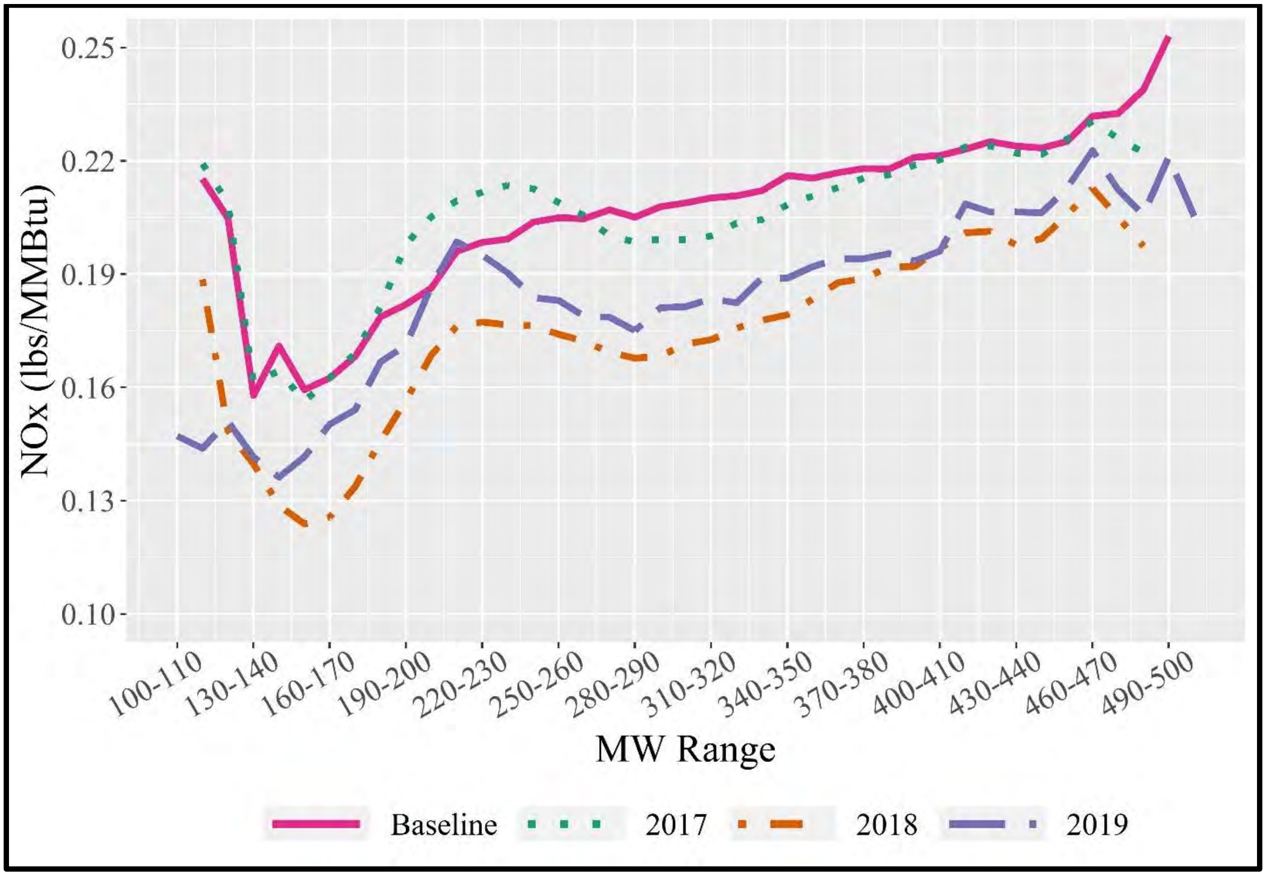

Figure 1 – NOx emission rate profile across unit load range

The vast majority of observed operation of the unit occurred in the megawatt ranges of 100 – 150 and 460 – 490 MW, and the parametric study of contributing factors was performed in these two ranges. The identified parameters which most impact NOx generation were included in this analysis: SOFA 1, 2, 3, and 4 damper positions and tilts; and Excess O2 measurement. Overfire air placement was found to move quite dramatically over the course of the project, moving from a uniform position due to manual tuning to varying positions from corner to corner as identified by the optimization system. Changes in O2 balancing across the unit are also displayed within this analysis, presented later in this report.

Installation, Implementation, and Evaluation of Optimizer and Neural Network

Assist PacifiCorp and Taber Int. personnel with the installation/implementation of the optimizer. Evaluate the neural network in operation and provide recommendations. Report on the performance of the neural network optimizer with regards to usage level, benefits received, benefits lost, and improvement recommendations.

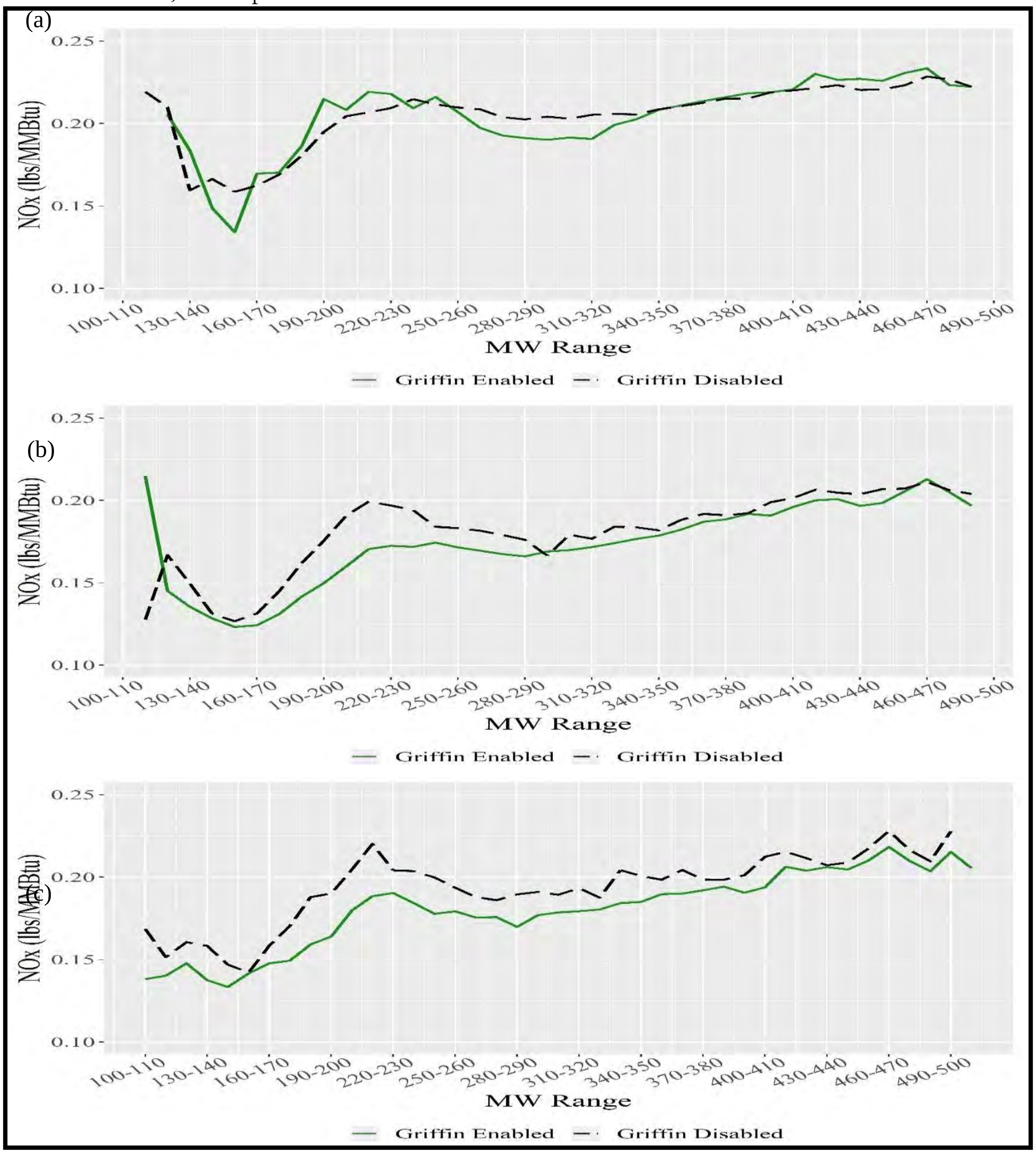

Figure 2 – Yearly NOx emission rate with Griffin system enabled and disabled: (a) 2017 (b) 2018 (c) 2019

Following the initial training phase of the system (latter portion of 2017), the NOx emission rate profile has always been improved by having at least one aspect of the Griffin optimization system enabled (excluding the lowest operating load in 2018 which saw very little application of Griffin, skewing the rate profile). The 2018 year saw a 7.7% improvement with Griffin enabled compared to disabled that year, and 2019 saw an 8.7% improvement with Griffin enabled compared to disabled that year. Although the average NOx emission rate increased from 2018 to 2019, the benefit received by the Griffin system increased, further supporting that the optimization system was continually learning and improving as more operation was experienced.

The overall service factor of the system over the project's length (beginning when the optimizer first became available) was 60.0%. The service factor during each annual period is shown below.

Table 1 – Annual Service Factor of COS

Period	Service Factor
2017	29.7%
2018	79.4%
2019	53.2%

The decreased service factor from 2018 to 2019 was primarily due to performance issues arising caused by hardware deterioration as the unit approached its scheduled overhaul during October 2019. The new circumstances encountered required many operators to disable the Griffin system in order to address the problems they were experiencing. A number of these were addressed post-event with expert logic development within the COS, but not all cases were able to be corrected in this manner.

A detailed analysis of the system's emission rate performance during many combinations of system disabled parameters are discussed later in this report.

Expansion of Neural Network and Further Research

Expand usage of optimizer to include auxiliary plant processes (e.g. cooling tower fan control, scrubber control, etc). Identify and conduct further research to enhance neural network control of unit performance.

Over the course of the project, a number of opportunities were identified and explored for expansion of the artificial intelligence modeling and optimization system and expert logic application. These areas were soot blower control, real-time classification of combusting coal quality, cooling tower fan speed, and superheat and reheat attemperator valves. Optimization of pump motors within the flue gas desulfurization (FGD) system was initially proposed as a potential project area, but after thorough consideration this topic was not selected for further analysis in order to pursue more potentially beneficial areas. Each of the analyzed systems and areas had differing objectives and were approached and analyzed according to different methods and metrics. Successes were achieved with each effort, and each is described thoroughly later in this report, with a brief summary of each provided below.

Sootblower Control: Knowledge-based Sootblowing (KSB) was developed in the earlier half of 2018, shortly after the combustion optimization system became functional. This project was largely led by Griffin Open Systems according to other applications they have performed of similar systems. The ultimate objective of soot blower control was to provide greater consistency to ash cleaning within the unit, leading to less tube metal wear and improved efficiency. The retract controller aspect of the system was used across the project for this purpose. The wall blower controller aspect of the system quickly evolved to aid in steam temperature control. This system was configured to automatically blow walls around the unit in response to rapidly increasing or already elevated steam temperatures in a manner to manage temperature with the fewest number of blows. Due to the high number of occurrences of elevated temperatures, the KSB system naturally led to more wall blower activations to achieve its evolved objective. Through many control iterations, the system has seen increasing service factor between annual periods, and is appreciated by operations for providing consistency between different crews with varying operating styles.

Table 2 – KSB Yearly Service Factor and Average Blower Activations

Year – Blower Type	Service Factor	System Active Average Activations	System Inactive Average Activations
2018 – Retracts	32.7%	41.9	37.3
2018 – Walls	29.2%	93.4	95.7
2019 – Retracts	68.2%	39.4	26.5
2019 – Walls	66.1%	107.8	66.4

Coal Quality Classification: The combustion process is significantly influenced by the quality of fuel within the system at that instant. Because of the nature of coal, the characteristics of the feed stock are not constant. Unfortunately, this is a largely unknown factor as measurement techniques to directly determine coal quality and relate it to current conditions are not available. In order to provide the neural network optimization system with more information of currently combusting coal quality, another type of artificial intelligence modeling method was developed and applied onsite. This system utilizes a Support Vector Machine (SVM) to classify the quality of currently combusting coal based on readily available system measurements such as the ratio of feeder speeds to current generation level and others. The SVM system then informs 3 new, specific neural networks trained exclusively on 3 unique coal quality classification outputs: good, ok, and poor. The application of this system was found to increase the prediction accuracy of the neural network models by nearly 50% on two weeks of unseen test data (Figure 3) and improve the optimization capability of the application.

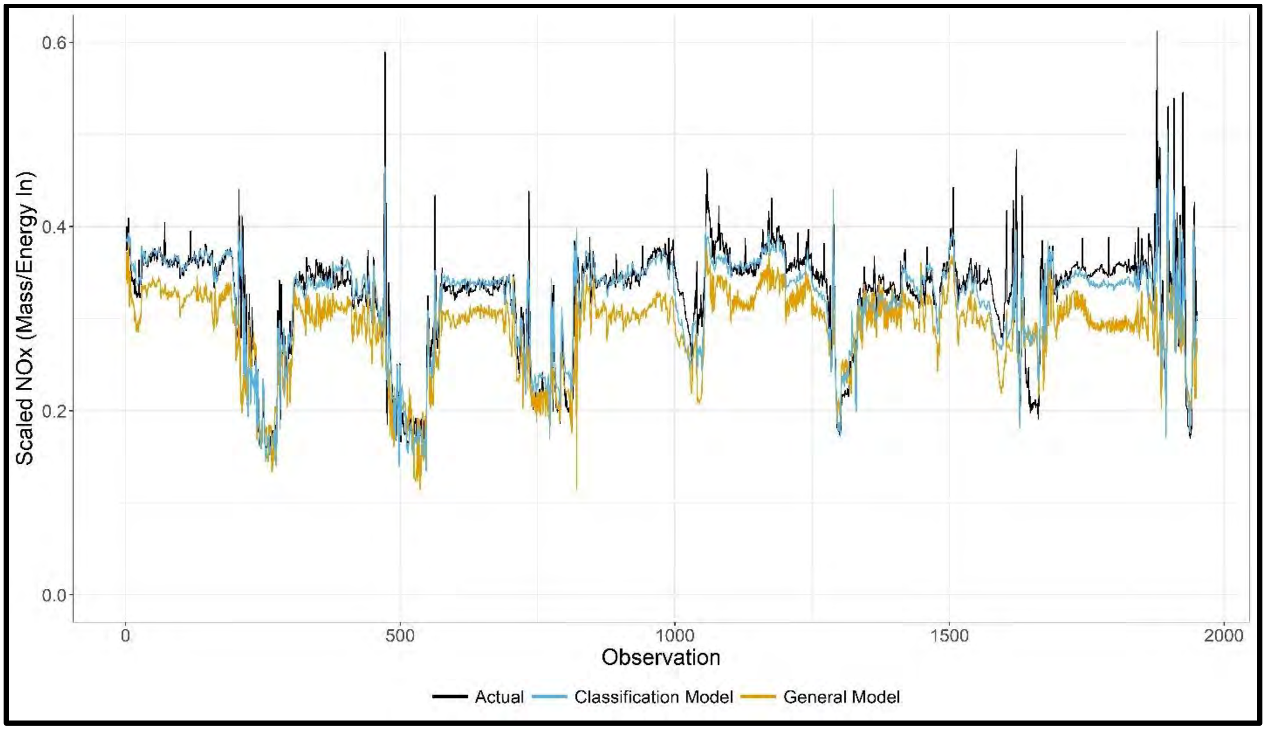

Figure 3 – Improved prediction ability of SVM classification neural network model (blue) against previously existing neural network model (orange)

Cooling Towers: Operation of the cooling tower represents a large parasitic power draw within the power plant, directly affecting net unit heat rate (NUHR). A neural network optimization system similar to the existing combustion optimization system was developed to reduce the power consumption of the fans within each cooling tower cell (12 fans). Equipped with variable-frequency drives (VFDs) these fans can be individually controlled to achieve the desired condensate cooling. Existing DCS controls assume that each cell is identical, however initial analysis confirmed that each cell behaves very differently, and their behavior changes as unit load changes.

Following a simulation study which predicted a potential theoretical power consumption reduction of 10%, the cooling tower optimization system was deployed onsite in closed-loop control on August 27th, 2019. Operation of this system continued until the unit's scheduled outage in October 2019. During this period, the power consumption of the cooling tower fans was 5.2% less on average with the Griffin optimizer active compared to when the Griffin optimizer was inactive, shown in Figure 4.

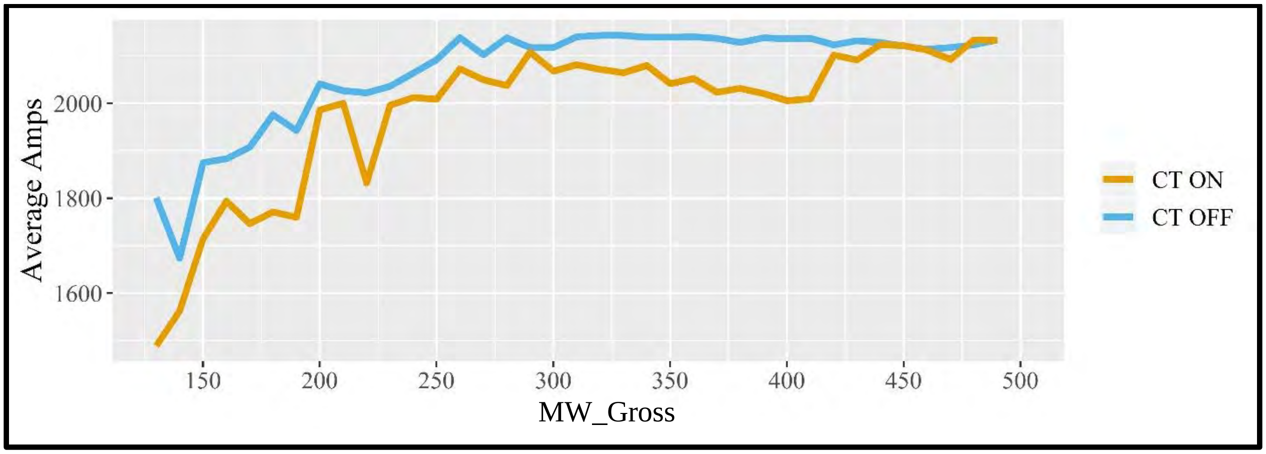

Figure 4 – Cooling tower power consumption (represented by amps) with Griffin Optimization active (orange) compared to off (blue) from Aug 27th to Oct 5th, 2019

Attemperator Valve Control: Attemperator valves at the Huntington power plant are known to be slow-acting and unresponsive, at times responding exactly opposite of what is needed (cooling steam below setpoint). Largely contributing to this is the new dynamics being encountered by the unit from fast ramping and operation at new loads. Utilizing previously existing bias points within the DCS to alter the setpoint of the existing attemperator valve control, an application within the Griffin system was developed to improve the attemperator valve response.

Working within the limitation of only being capable of altering an underlying PID setpoint, a number of control system methods were attempted (fuzzy feedback control, PID control, curve-fitting and first-principles based modeling). The best identified system was found to be PID control utilizing a properly tuned derivative component and integral reset. The system became available August 27th. Since that time, the amount of time that the unit has experienced main steam temperatures above 1050° is 50% lower with the Griffin attemperator valve control active compared to inactive (reduced from 1% of operating time to 0.5% of operating time). The amount of time of observed main steam temperatures above 1050° is shown in Figure 5. Due to the attemperator control system being developed later in the year, its service factor during 2019 was only 9.7%. It has been well accepted by operations however, and is expected to see a high service factor in the future.

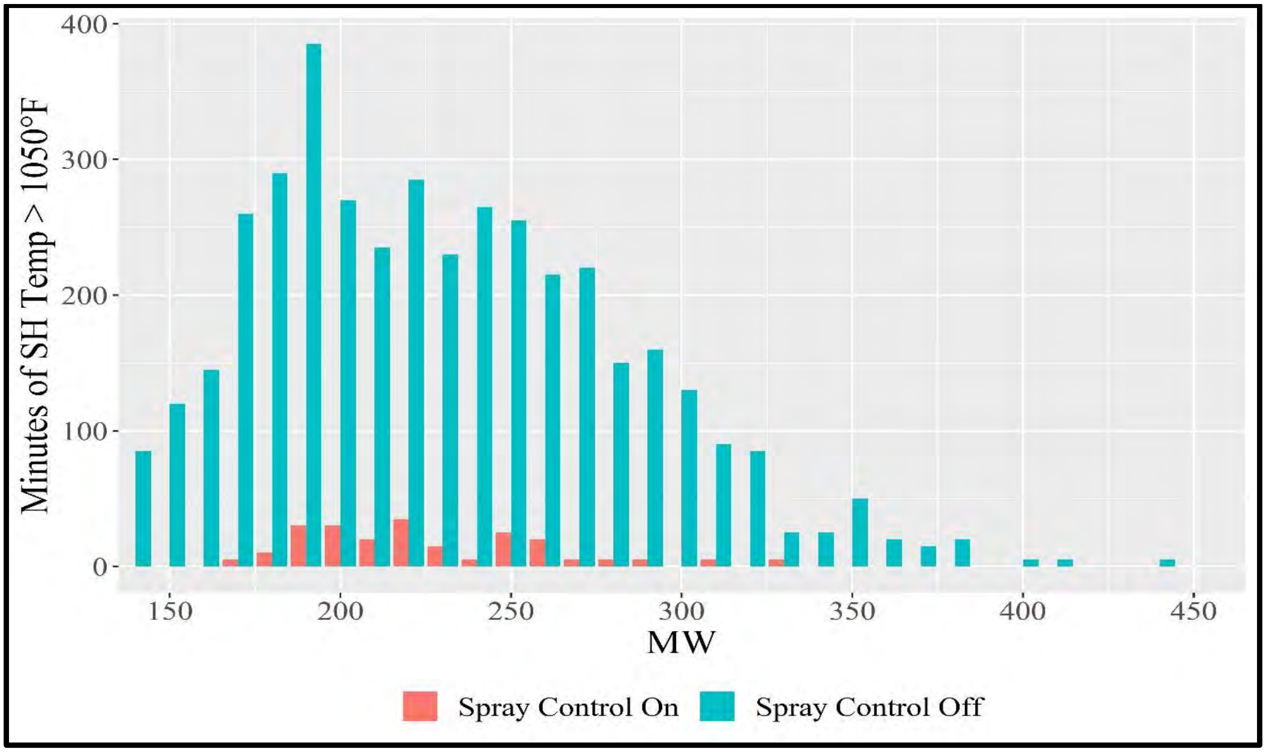

Figure 5 – Observed time of main steam above 1050° with Griffin Attemperator Control active and inactive during 2019.

System Adoption

Evaluate factors that may discourage system usage e.g. poor human machine interface, excessive maintenance, lack of understanding or trust by operators, etc. Where possible, identify mitigation opportunities and aid in their implementation.

Over the course of the project, operator adoption of the newly created combustion optimization system and the additional control systems created was largely affected by changes in operating behavior of the unit, individual operator experience at different loads and in changing circumstances, operator oversight, and the onsite presence of the research team. A table of the quarterly service factor of the COS is displayed and discussed in Table 3.

Table 3 – Project timeline service factors with corresponding major events and developments

	QI - QIII 2017	QIV 2017	QI 2018	QII 2018	QIII 2018	QIV 2018	QI 2019	QII 2019	QIII 2019	QIV 2019
Service Factor	0%	49%	66%	54%	80%	86%	77%	69.0%	61.0%	6.0%
System Changes	Install & Learning Phase	COS Activated		KSB Activated	SOFA Tilt for Tube Temps			Low Load O2 / SVM Coal Quality	Spray and Cooling Tower	Unit Overhaul & Learning

The quarterly performance of the system and developments during each quarter shown in Table 3 suggest that the most influential single event which occurred to improve service factor was the development of the SOFA Tilt controller to help manage high tube temperatures, which during QIII of 2018. This controller was developed in direct response to reoccurring challenges faced by operators which were a priority for them to maintain. Previously existing methods for control resulted in detrimental behavior to other portions of the system. The SOFA Tilt method developed here was able to reduce measured high four-tube average temperatures by more than 80%, with no direct detrimental side effects, as the NOx emission rate profile continued to decrease during QIII 2018 and after.

Additional factors related to system adoption are discussed later in this report.

Neural Network Operator Training

Provide ongoing training to plant operators and others on operating optimization system.

The continual onsite presence of the research team's Jake Tuttle led to many opportunities to interact with operations and management and perform training as needed. In most situations, this took on the form of asking and answering questions to explain certain behaviors of the system and overall objectives. Often times, this process led to new developments and further refinements within the optimization system to help operators address circumstances encountered within the unit automatically.

During the latter half of 2019, a weekly meeting was organized by engineering and operations management to unite and inform everyone affected by the project of the current status of the neural network optimization system and challenges faced by operations. This practice was very beneficial, leading to further system adjustments of optimizer operating ranges while the unit prepared for its October 2019 outage. A summary guide explaining the expected behavior of the neural network system and operating performance was provided and updated with new changes throughout this time.

With years' worth of interaction between the research team and operations, each control room operator is familiar with the optimization system and its objectives and behavior. Many operators have stated that they are satisfied with how the system functions in most situations, and understand that in any circumstance they can disengage the system to address other unit issues. Most re-activate the system after those issues are resolved, allowing the optimization system to continue to provide benefits to NOx emission rates.

Establishment of KPI's

Help to establish KPI's for success e.g. NO_x emission levels < X.XX lbs/MMBtu, CO less than permitted value, X.XX% Net Unit Heat Rate (NUHR) reduction, etc.

Established NOx emission goal: 0.19 lbs/MMBtu

Established CO emission goal: between 90 and 250 ppm

Throughout the project's length, the emission rate profile of NOx (Figure 1) shows, despite the percent improvements realized through use of the optimization system, no year saw the full emission rate profile across the unit's load range below the established NOx emission rate goal of 0.19 lbs/MMBtu. The CO emission rate profile during each year of the project at loads above 160 MW was within the objective range (except for one outlier at an extreme high load point). This shows improvement in CO management compared to the baseline CO emission rate profile. Below 160 MW the unit is affected by a total minimum air flow limit which is unavoidable due to safety reasons. High levels of excess air cause CO emission rates to go to 0, and cannot be addressed without major DCS changes outside the scope of this project.

The overall yearly average NOx emission rate and CO emission rate are shown in Table 4.

Table 4 – Average NOx and CO emission rates

	Baseline	**2017**	**2018**	**2019**
NOx (lbs/MMBtu)	0.206	0.206	0.185	0.184
CO (ppm)	192	130	104	113

The average NOx emission rates during 2018 and 2019 are below the target value of 0.19 lbs/MMBtu. However, this overall average is likely lower due to significantly more operational time at lower loads, which inherently generate less NOx emissions.

Based upon the performance of similar systems at other sites, additional operational time and use of the optimization system will continue to improve the system's performance and the NOx emission rate reduction ability. Neural network models benefit from more data to train and learn from, and as the system continues to gather data and retrain itself, it is expected that additional benefits will be realized.

Year-Round Support

Provide year-round onsite coverage and support

During the initial learning stages of the project, university personnel traveled to the plant site weekly to take part in research and installation activities with Griffin Open Systems personnel. Beginning mid-quarter of QII 2018, research team member Jake Tuttle has been onsite nearly daily during the project period to evaluate system performance and perform tuning and development of new control techniques. Additionally, by having a constant presence onsite, problems and issues were immediately addressable and often resolved within the day. All partners and members of the research team have been available throughout the project's duration via email and phone for questions and troubleshooting.

These practices have established strong long-term relationships between all partners which will help to support the overall Griffin system's functionality and use for years beyond the project's completion.

Details of Work Performed:

Parametric Study

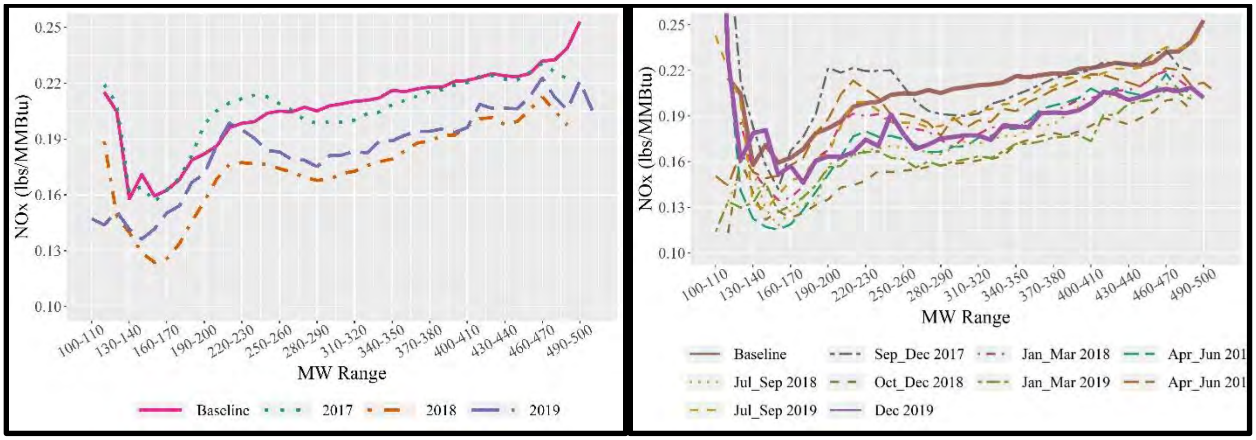

Figure 6 – Yearly and quarterly NOx emission rate profiles

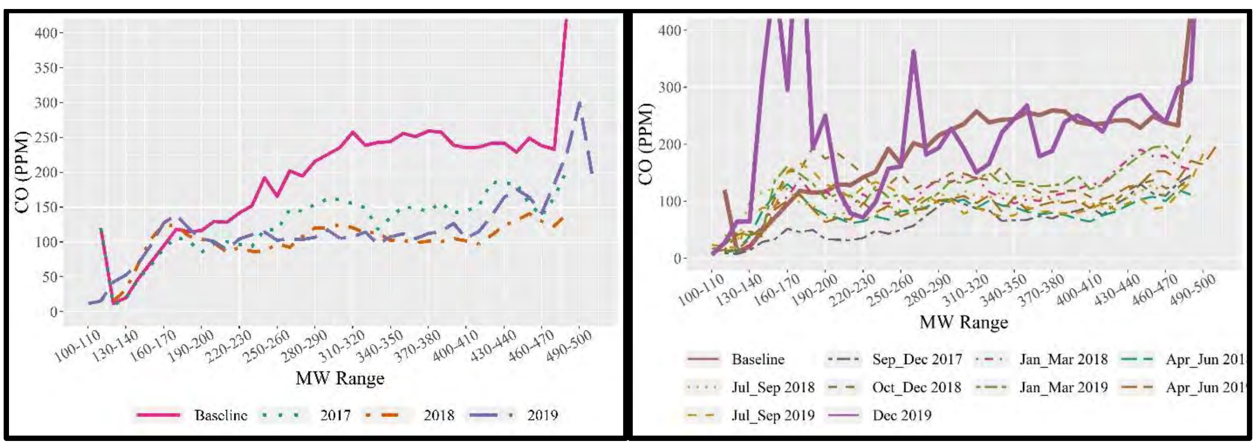

Figure 7 – Yearly and quarterly CO emission rate profiles

Performance and behavior of the unit varies considerably based on the current generation level. To best compare emission rates across time, comparison of individual generation ranges provides the most accurate results. The load range of the unit was broken into 10 MW increments, and the observed NOx and CO values within each of these MW bins was averaged to generate the profiles in Figures 6 and 7.

The NOx emission rate profiles were the main focus of this project, and the neural network models generated were always used to predict NOx emission rate and used to optimize damper and tilt positions across the boiler. CO was mainly controlled using the excess O2 trim bias, which operated according to a fuzzy controller to remove or add O2 in response to current CO ppm levels to remain with the target range of 90 – 250 ppm.

A parametric study of the behavior of SOFA air placement and resulting excess O2 measured across the backpass of the unit was conducted to understand some of the correlations being identified and exploited by the neural network and how this was affecting O2 balancing. Because the majority of unit operation occurs above 460 MW and below 150 MW, an analysis of high load behavior (460 – 490 MW) and low load behavior (100 – 150 MW) was performed of the average positions of these parameters during each annual period. Additionally, the best NOx performance records were isolated from these datasets to further recognize relationships which promote excellent NOx emission rates. For the low load range, NOx records below 0.13 lbs/MMBtu were considered, and for the high load range, NOx records below 0.18 lbs/MMBtu were considered. The behavior of each level of SOFA dampers and tilts, and the O2 probes are displayed in Figures 8 – 15.

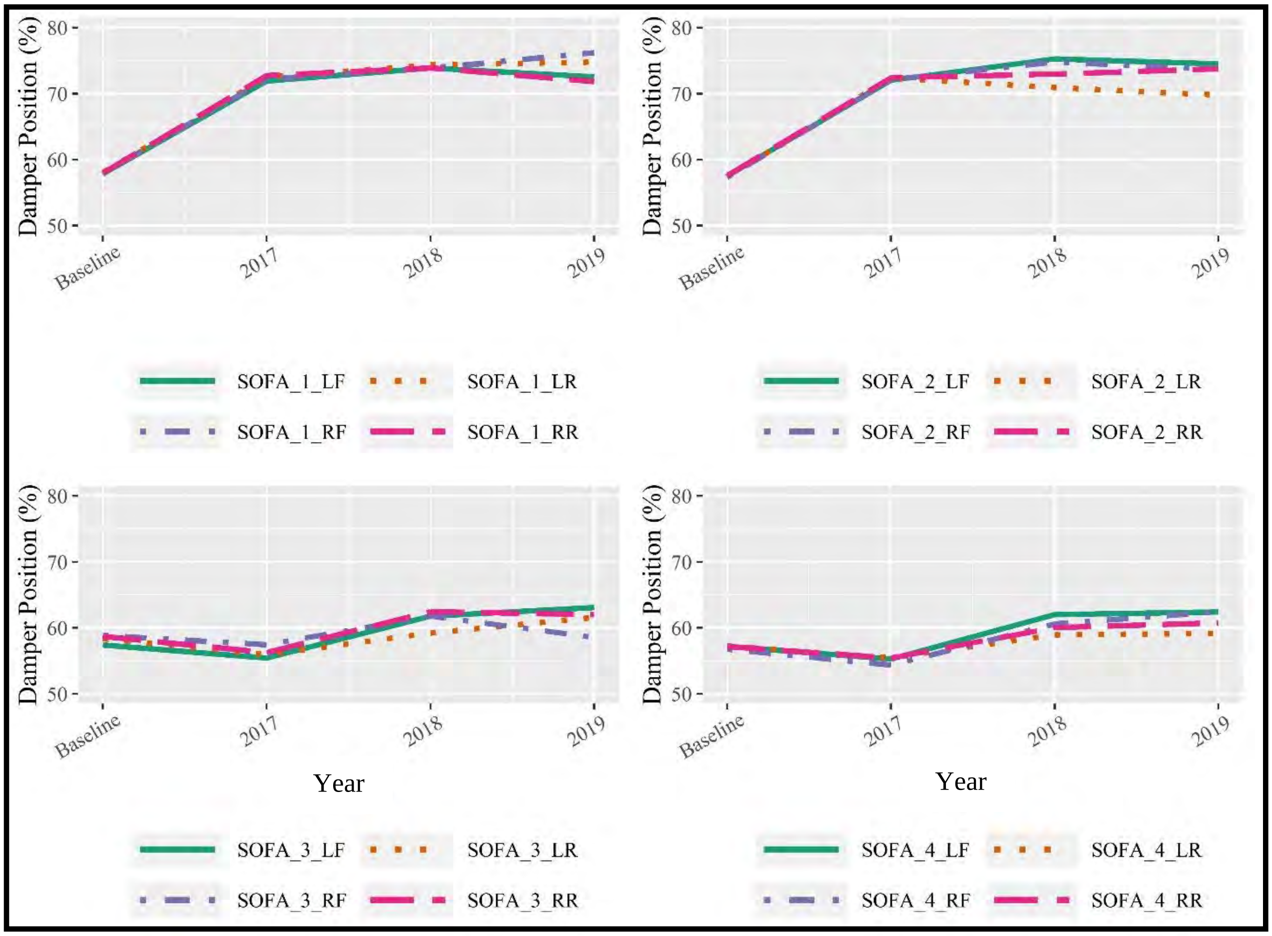

Figure 8 – SOFA damper levels average position during each annual period at high load

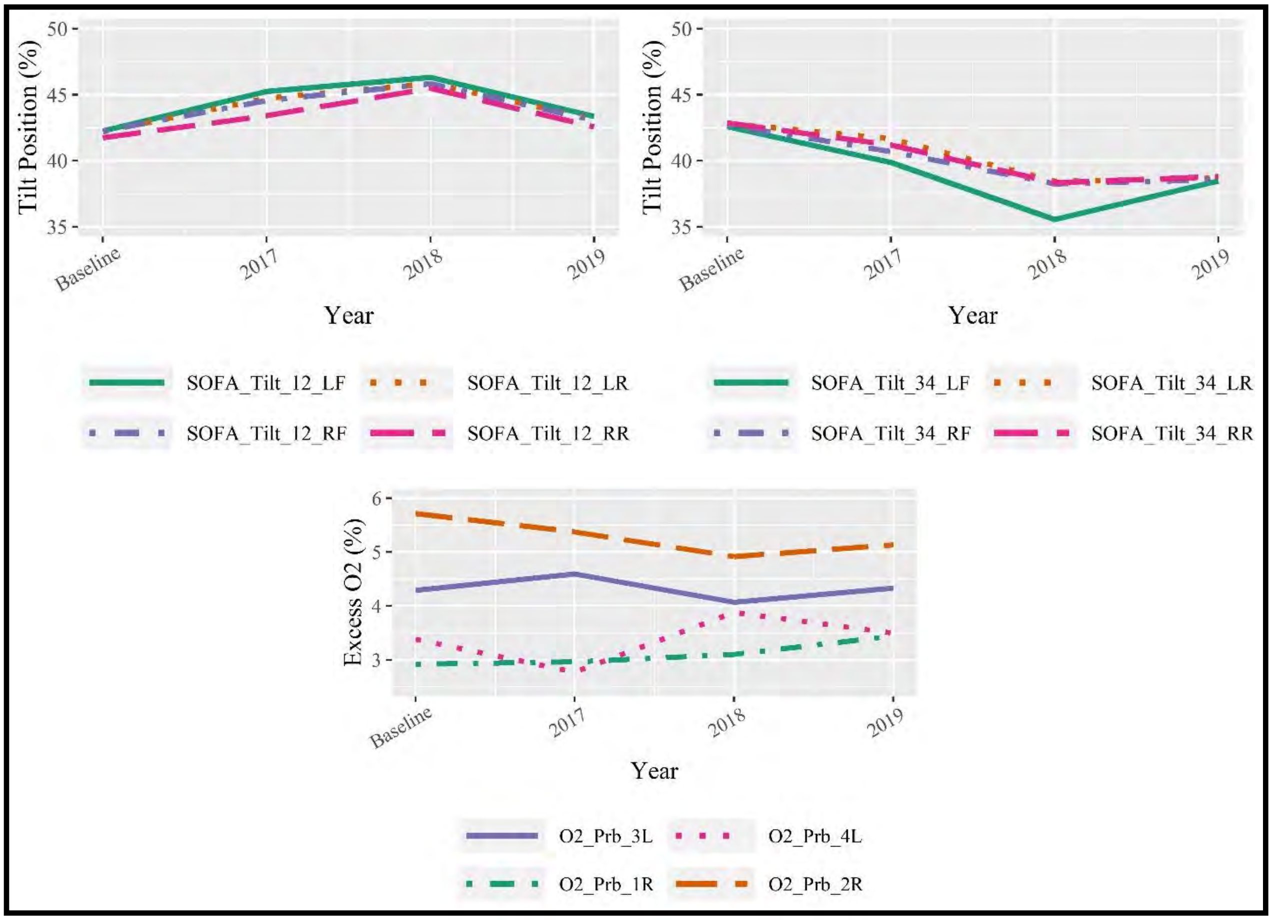

Figure 9 - SOFA tilt average positions and excess O2 averages during each annual period at high load

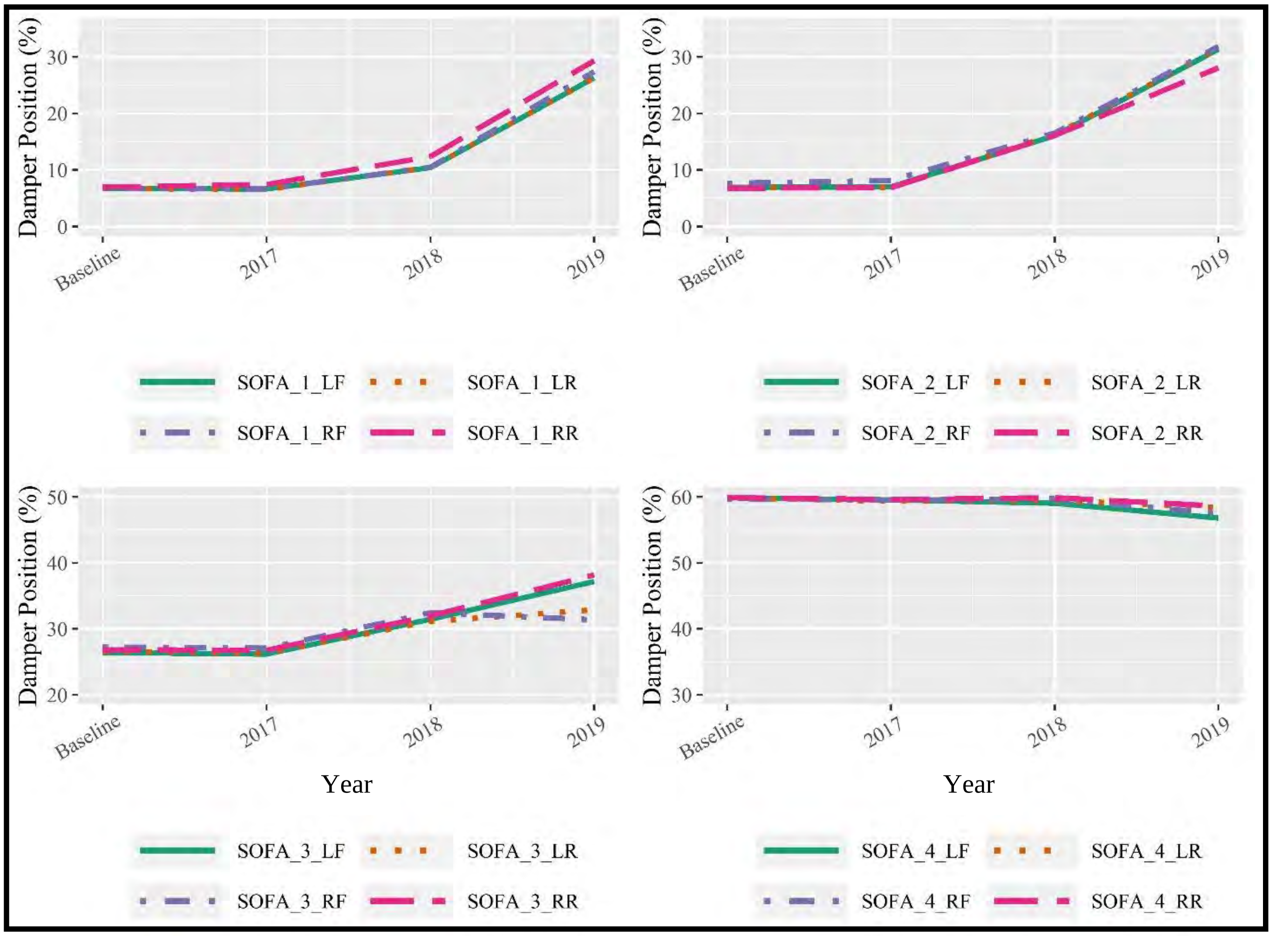

Figure 10 - SOFA damper levels average position during each annual period at low load

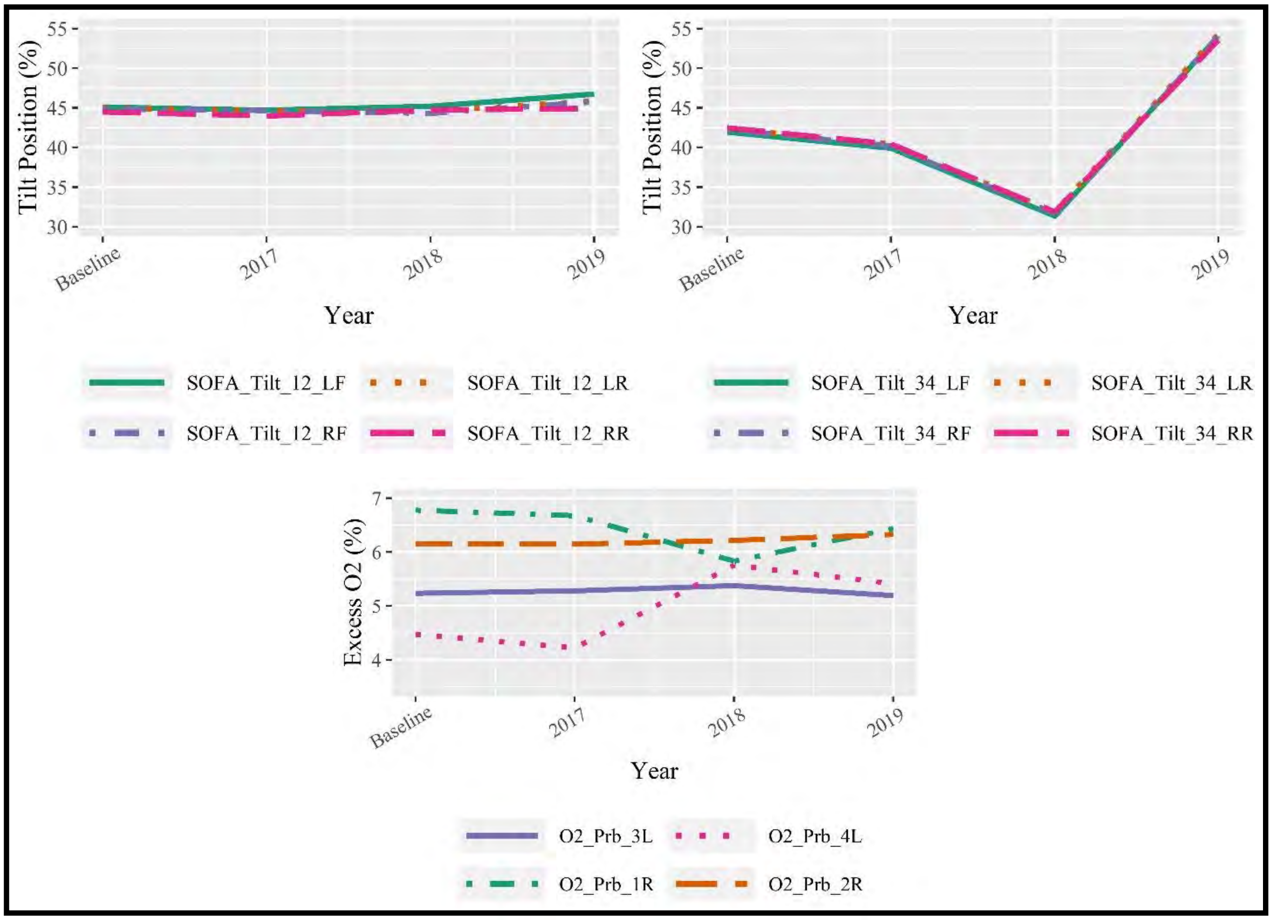

Figure 11 - SOFA tilt average positions and excess O2 averages during each annual period at low load

At both low and high load, we see that as the optimizer realized greater benefits compared to operation without the optimizer active, larger differences began to exist from corner to corner on individual levels of the SOFA dampers. We also see that the SOFA dampers generally became more open as time went on. Also at both low and high load, we see that O2 probes appear to be more even and balanced during 2018 and 2019 compared to the baseline period and 2017.

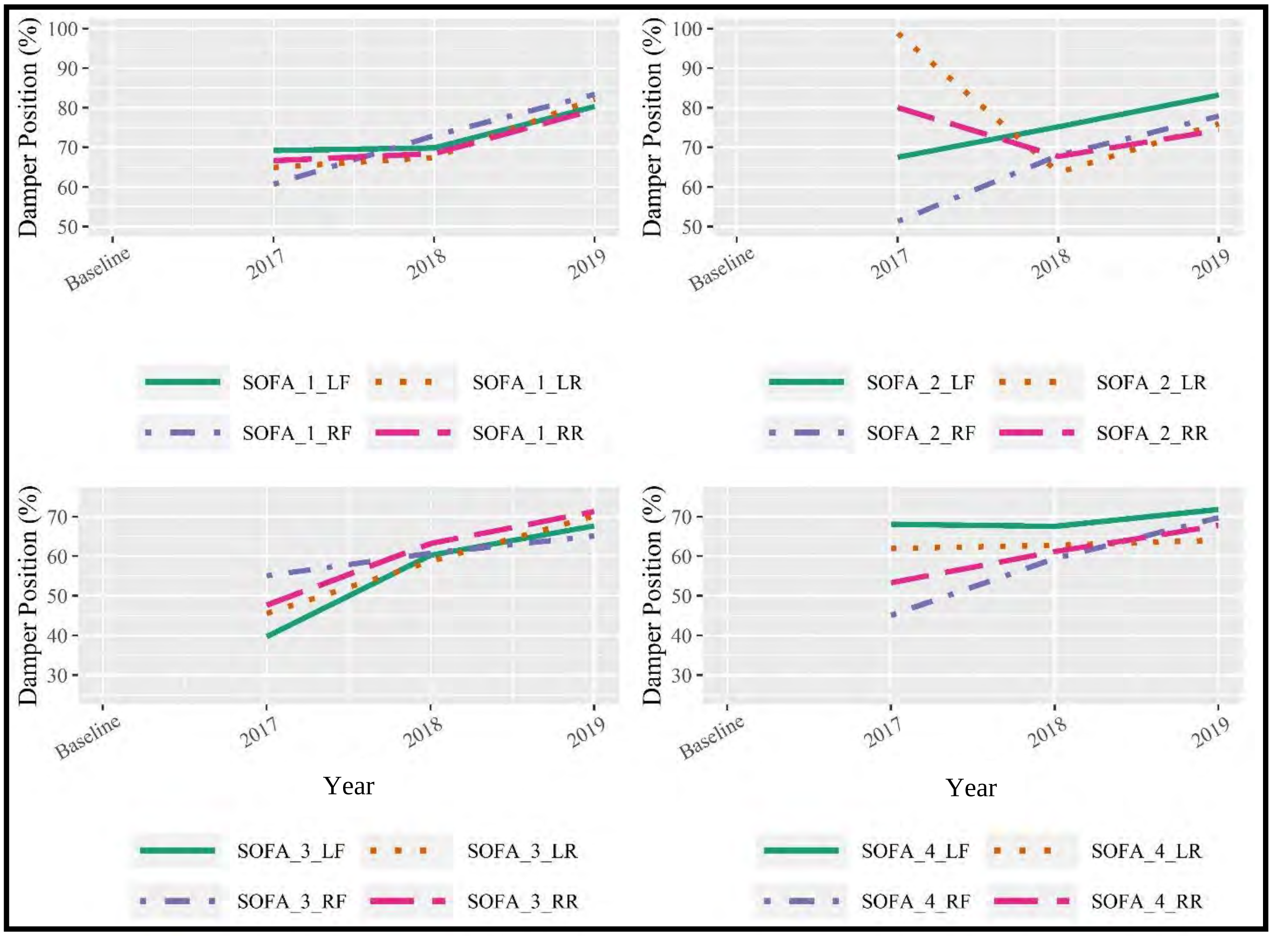

Figure 12 - SOFA level damper position averages during each annual period at high load where NOx emission rates were observed to be less than 0.18 lbs/MMBtu

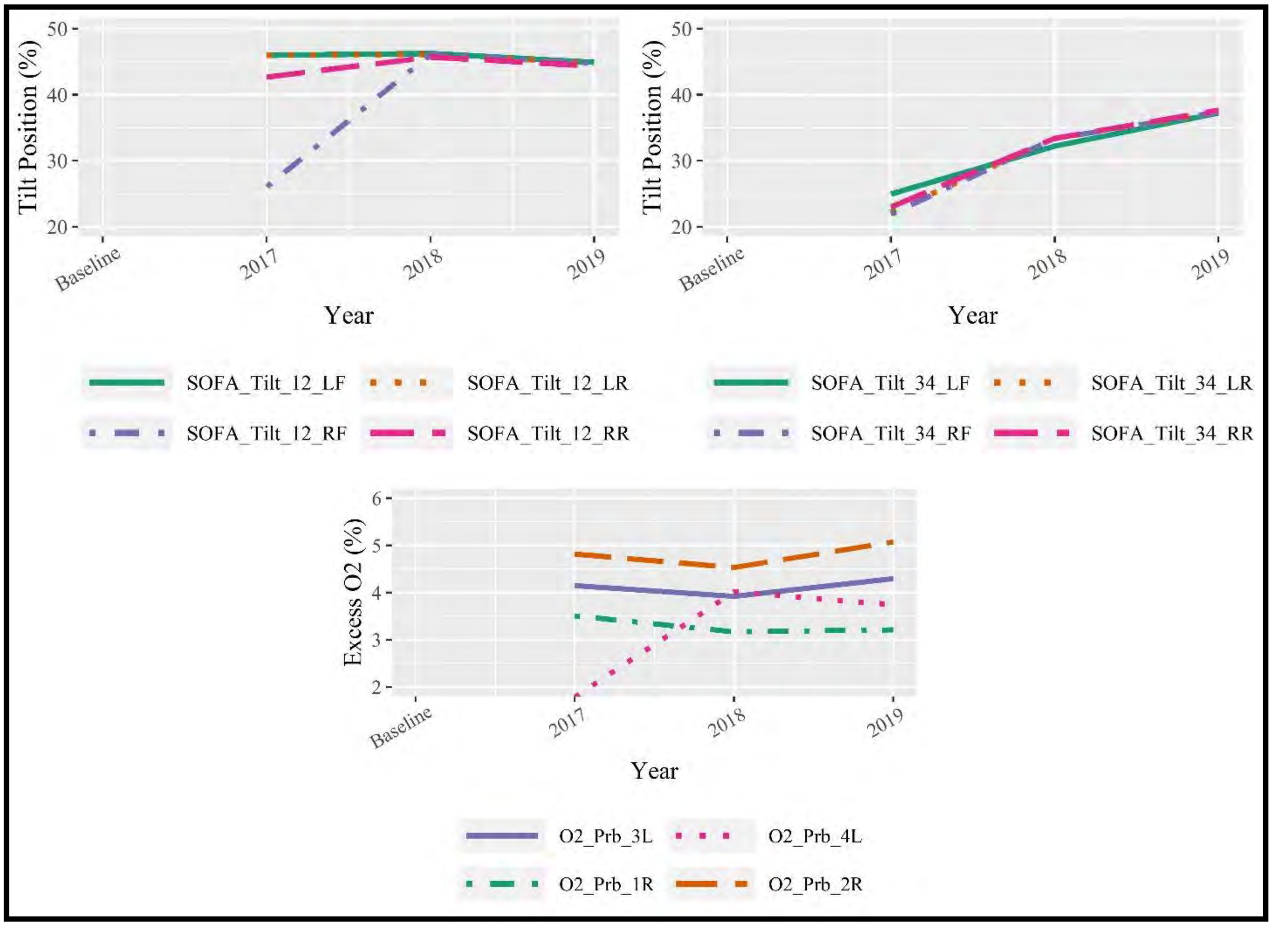

Figure 13 - SOFA tilt average positions and excess O2 averages during each annual period at high load where NOx emission rates were observed to be less than 0.18 lbs/MMBtu

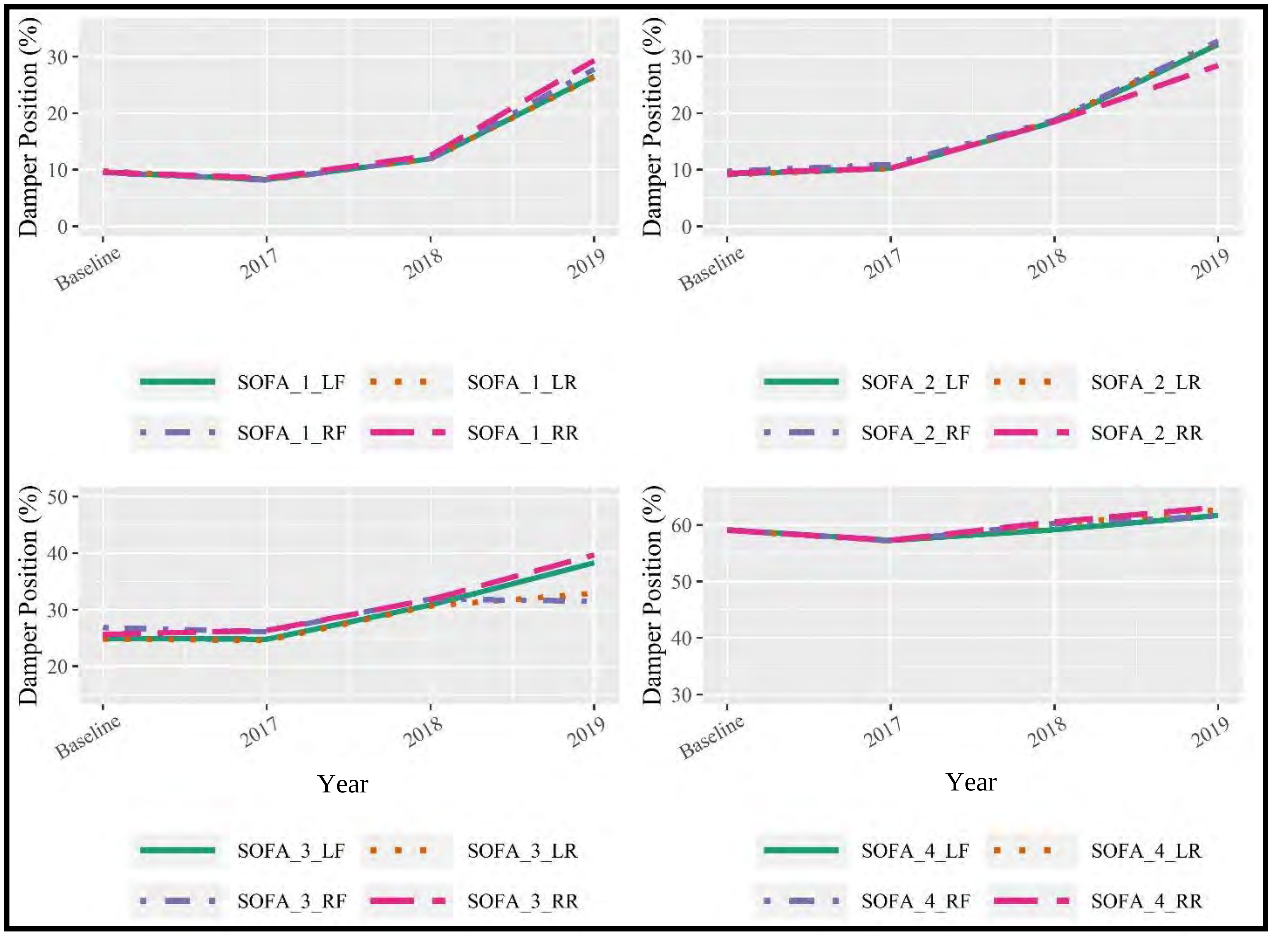

Figure 14 - SOFA level damper position averages during each annual period at low load where NOx emission rates were observed to be less than 0.13 lbs/MMBtu

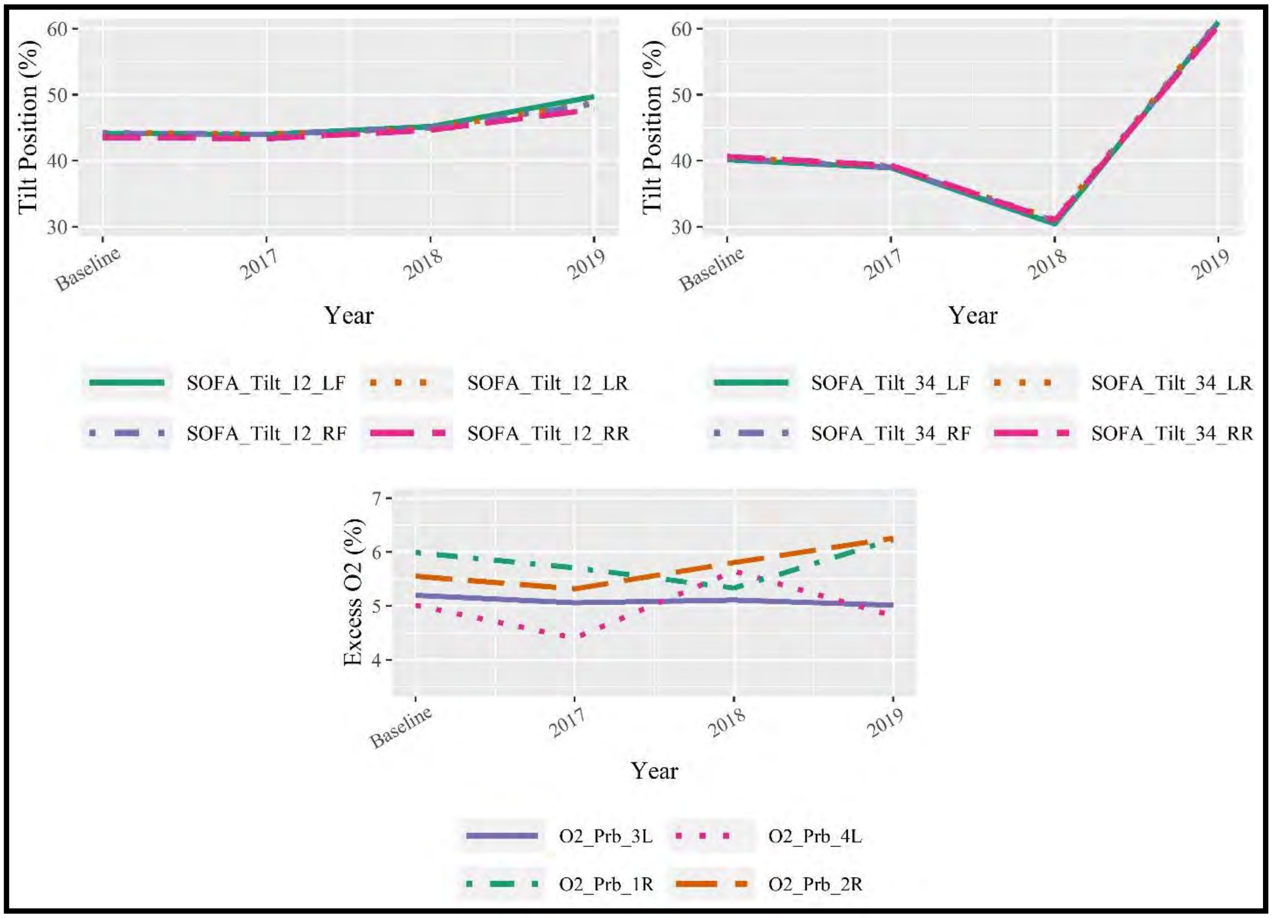

Figure 15 - SOFA tilt average positions and excess O2 averages during each annual period at low load where NOx emission rates were observed to be less than 0.13 lbs/MMBtu

The baseline period contained no records at high load where NOx emission rate was observed to be below the 0.18 lbs/MMBtu threshold, as seen by the absence of parameter values in Figures 12 and 13. The best NOx configurations contained much fewer records than the overall analysis, which contributed to the larger differences from corner to corner of many parameters and the less generalized trends of behavior. Regardless of this, we do see some important phenomenon which may be able to be utilized in the future by operations. At both low and high load, SOFA tilt position, particularly lower SOFA tilt positions, were higher during 2019 where the greatest improvement with the Griffin optimization system active was realized relative to operation without. Low load O2 probes appear to be within 1% (reading) of one another across all periods. SOFA dampers at both low and high load trend to more open as time goes on.

Installation, Implementation, and Evaluation of Optimizer and Neural Network

Service factor of individual components of the system during each quarter were evaluated and NOx emission rate performance within each situation displayed to better understand shortcomings of the system and areas where further attention should be paid. Project length service factors of each component are available within Table 5.

Table 5 – Quarterly service factor of individual components of the optimization system during project

	Sep – Dec '17	**Jan – Mar '18**	**Apr – June '18**	**July – Sep '18**	**Oct – Dec '18**
Any Griffin Control	48.9%	65.7%	54.1%	79.8%	86.2%
Griffin Fully On	10.3%	1.9%	15%	49.8%	65.5%
Griffin O2 Off	0%	0%	0.7%	2.5%	13.5%
Griffin WB Off	0%	29.5%	2.2%	0.9%	0.1%
Griffin O2 & WB Off	0%	21.9%	3.3%	1.6%	1.1%
Griffin SOFA Tilts Off	0%	0%	33.5%	13.7%	0.1%
Griffin O2 & SOFA Tilts Off	0%	0%	3.7%	3.8%	0%
Griffin Upper SOFA DMPs Off	0%	0.7%	0.8%	0.6%	0.4%
Griffin O2 & Upper SOFA DMPs Off	0%	1.8%	0.7%	1.3%	0%
Griffin Fully Off	51.1%	34.3%	45.9%	20.2%	13.8%
		Jan – Mar '19	**Apr – Jun '19**	**July – Sep '19**	**Oct – Dec '19**
Any Griffin Control		76.9%	69.0%	61.0%	6%
Griffin Fully On		43.5%	42.1%	26.4%	5%
Griffin O2 Off		18.3%	4.8%	14.5%	0%
Griffin WB Off		1.1%	3.5%	0.2%	0%
Griffin O2 & WB Off		6.2%	4.2%	6.3%	1%
Griffin SOFA Tilts Off		0.1%	0.7%	0.3%	0%
Griffin O2 & SOFA Tilts Off		0.5%	0%	1.1%	0%
Griffin Upper SOFA DMPs Off		0.5%	1.9%	1.3%	0%
Griffin O2 & Upper SOFA DMPs Off		0.3%	0.4%	3.3%	0%
Griffin Fully Off		23.1%	31.0%	39.0%	94%

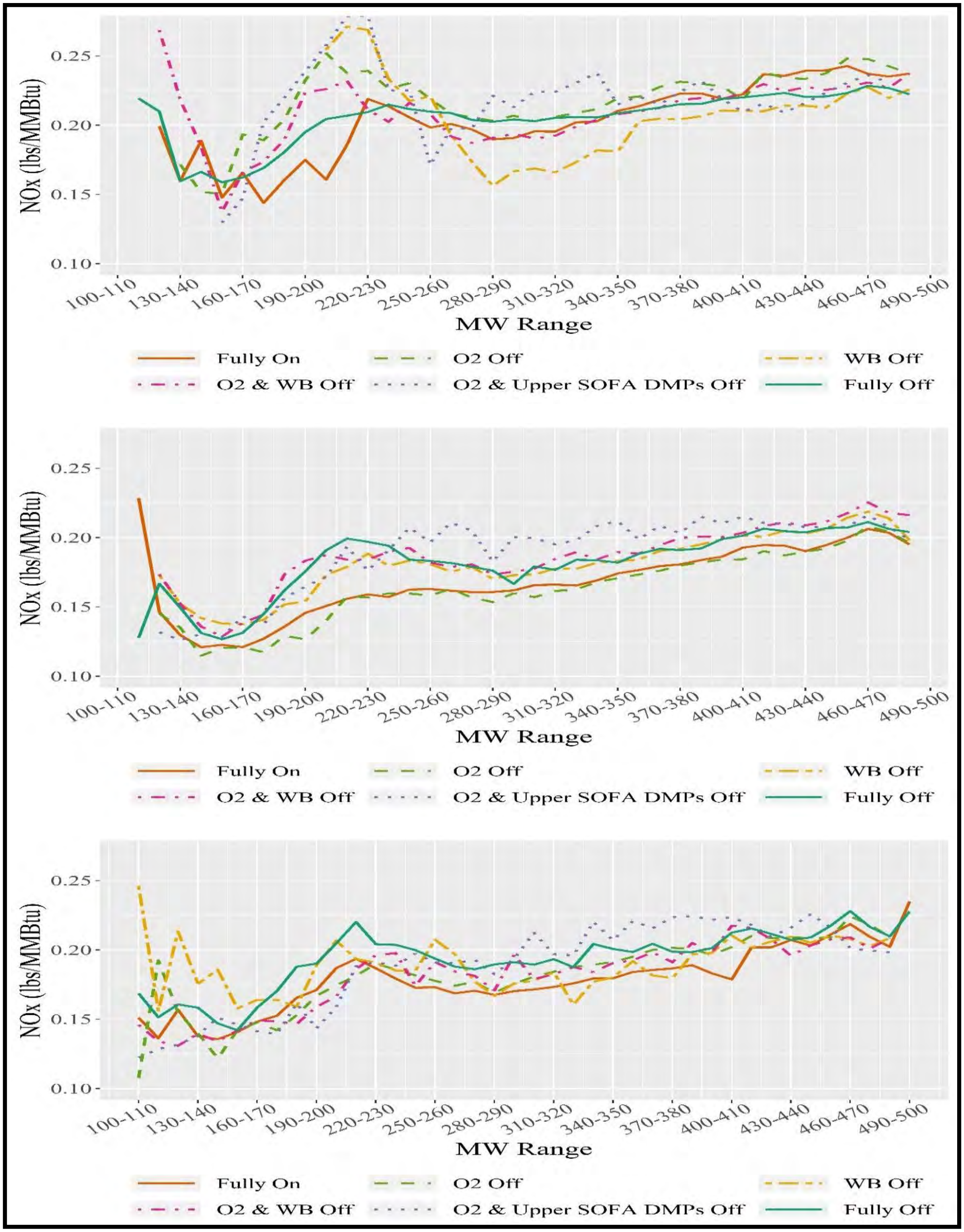

Figure 16 – NOx emission rates with various components of Griffin system out of service

During the 2018 and 2019 periods where the optimization system was fully active, we see that the system typically performed best with all parameters in service, or when the O2 controller was inactive. The fact that the system performed well and realized NOx reductions with the O2 controller inactive provides further support to the effectiveness of air staging and placement for combustion optimization, as generally the removal of excess O2 leads to NOx benefits.

During 2018, all other combinations of components being out of service performed about the same or worse than the system being completely off. This had changed by 2019, where all but the O2 and upper SOFA dampers out of service performed similarly to or better than the system being fully off. Having the WB component out of service performed much worse at the lowest loads during 2019.

Expansion of Neural Network and Further Research

Sootblower Control: Knowledge-based Sootblowing (KSB) was first activated July 1, 2018. The retract blower portion of this system has remained relatively unchanged, with only small adjustments to time windows and knowledge rules being performed. In general, the retracts were activated more often by KSB to enhance heat transfer to the steam from combustion gases and improve overall efficiency.

The wall blower portion of the system was primarily used to aid in steam temperature management, being developed heavily during 2018 to respond to rapidly increasing steam temperatures and high temperatures. Table 2 earlier in this report displays the average activations of each blower type during the 2018 and 2019 periods with KSB active and inactive. Daily sootblower activations and KSB service factor for the 2018 and 2019 periods are displayed in Figure 17.

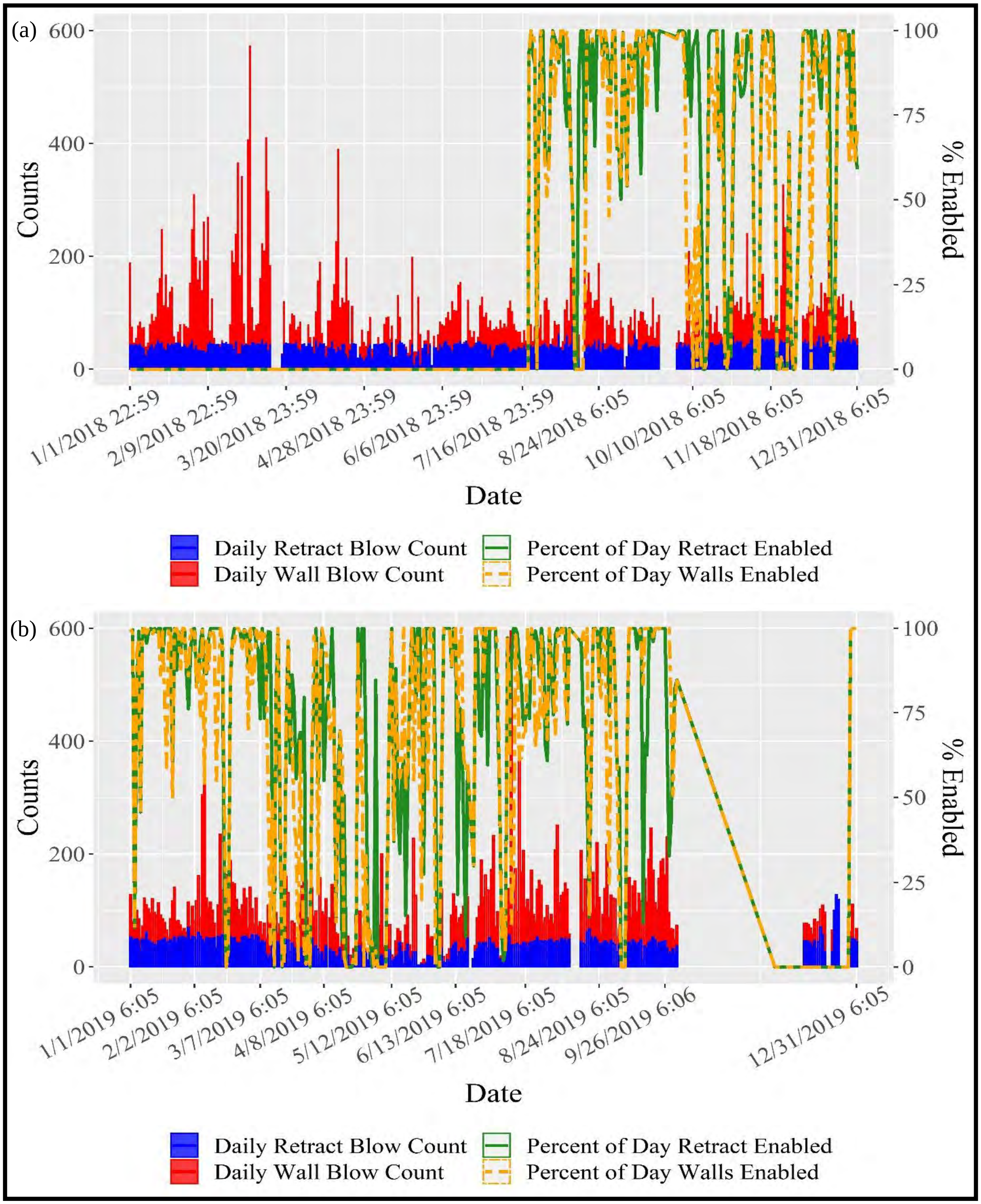

Figure 17 – Sootblower activations and KSB service factor during (a) 2018 and (b) 2019

Coal Quality Classification: To provide the neural network optimization system with real-time information about currently combusting coal quality, another type of artificial intelligence modeling method was developed and applied onsite. This system utilizes a Support Vector Machine (SVM) to classify the quality of currently combusting coal. New combustion features were engineered to better represent factors related to coal quality such as BTU, moisture, sulfur, and ash content. This feature engineering procedure utilizes readily available parameters available from the DCS, and transforms them by combining multiple parameters to more indicative of the coal quality parameters just mentioned. Four features were created to inform the SVM model:

$$Load2Coal = \frac{MW_{Gross}}{Total\ Fuel\ Flow} \qquad Hardness = \frac{Mill\ Amps}{Feeder\ Speed}$$

$$Drying\ Air = \frac{Total\ Hot\ Air\ DMP}{Load2Coal} \qquad Normalized\ SO_2 = \frac{Inlet\ SO_2\ PPM}{Total\ Fuel\ Flow}$$

Data from the online coal analyzer was used to confirm relationships and create a labeled set for SVM training. The coal analyzer data had to be manually matched to combustion data, which were found to be mismatched by anywhere from 2 to 8 hours, depending on load. With the datasets manually matched, the newly created features were compared to BTU/lb, moisture-%, sulfur-%, and ash-%. Figure 18 shows the relationship of a subset of these features, ash content related to "Load2Coal" and moisture-% related to "Drying Air".

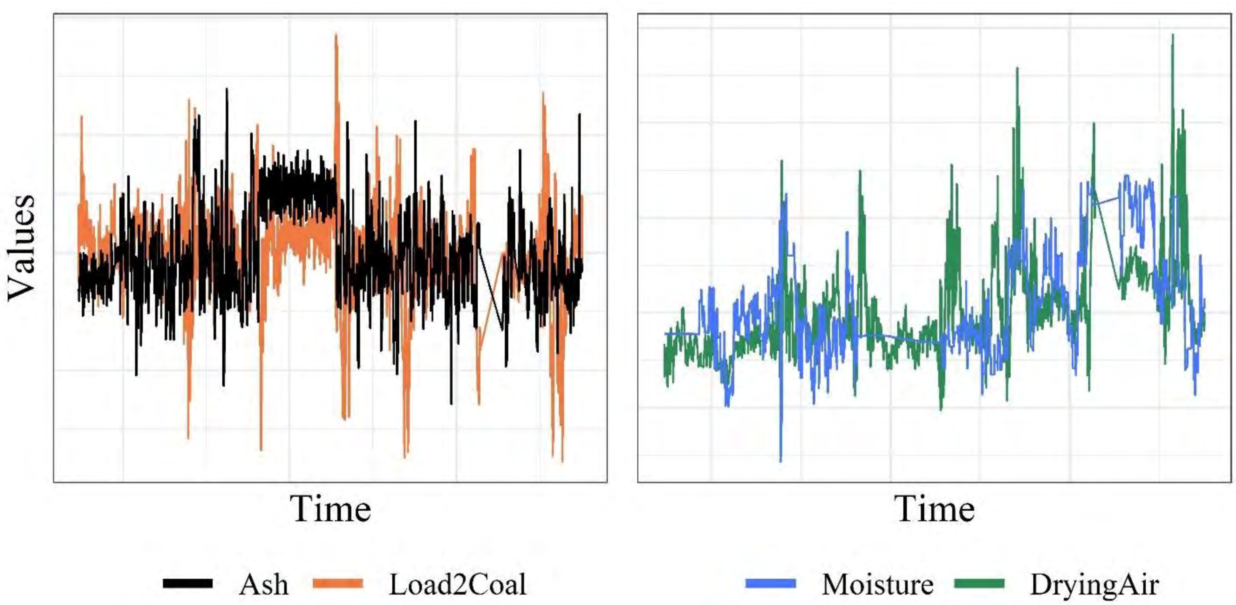

Figure 18 – Engineered features related to measured coal analyzer data

Although the relationships are not identical, the trends and correlations are near enough to provide improved information to the SVM classification model. The SVM model was trained using the labeled matched set and a classification system which balanced the contribution of coal quality indications from the analyzer data to qualities of "good", "ok", and "poor". This classification system was developed through interactions with operators and their knowledge of each parameter's general effect on combustion performance.

By classifying the existing dataset, it could be separated into unique datasets comprised only of each quality record (i.e. a "good" dataset, an "ok" dataset, and a "poor" dataset) and used to train unique neural networks. This process of reducing the dataset to similar conditions reduces variance error inherent in machine learning models, and helps to make the neural networks more accurate.

With each of these components available, the coal quality classification system was developed within the Griffin toolkit to perform prediction in real-time. A comparison of the previous method and this new approach is shown in Figure 19.

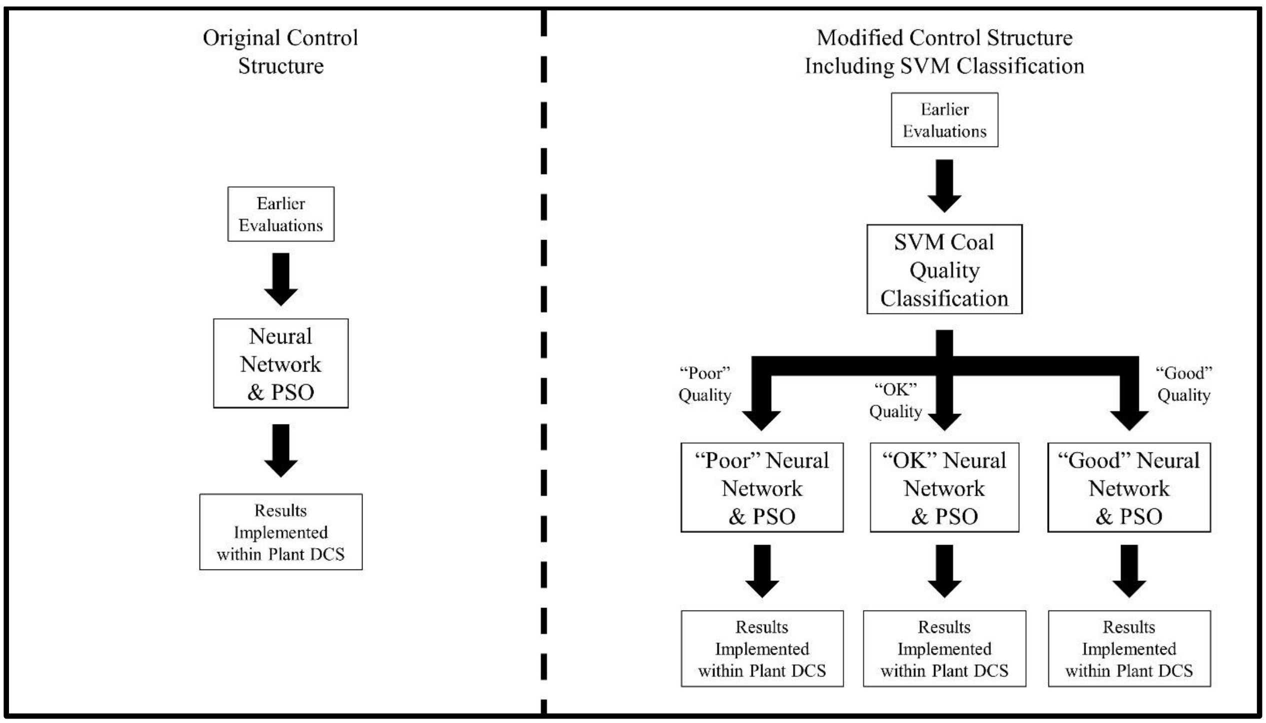

Figure 19 – Original control structure and neural network implementation in the SVM informed structure

NOx prediction ability using this modified neural network structure was found to improve prediction accuracy by nearly 50% on a two-week dataset. Since, these enhanced neural network models have been implemented and used by the optimization system within the COS.

Following the unit outage in October 2019, the SVM system was never reconstructed and trained to be applicable to performance changes resulting from the overhaul, and is currently out of service.

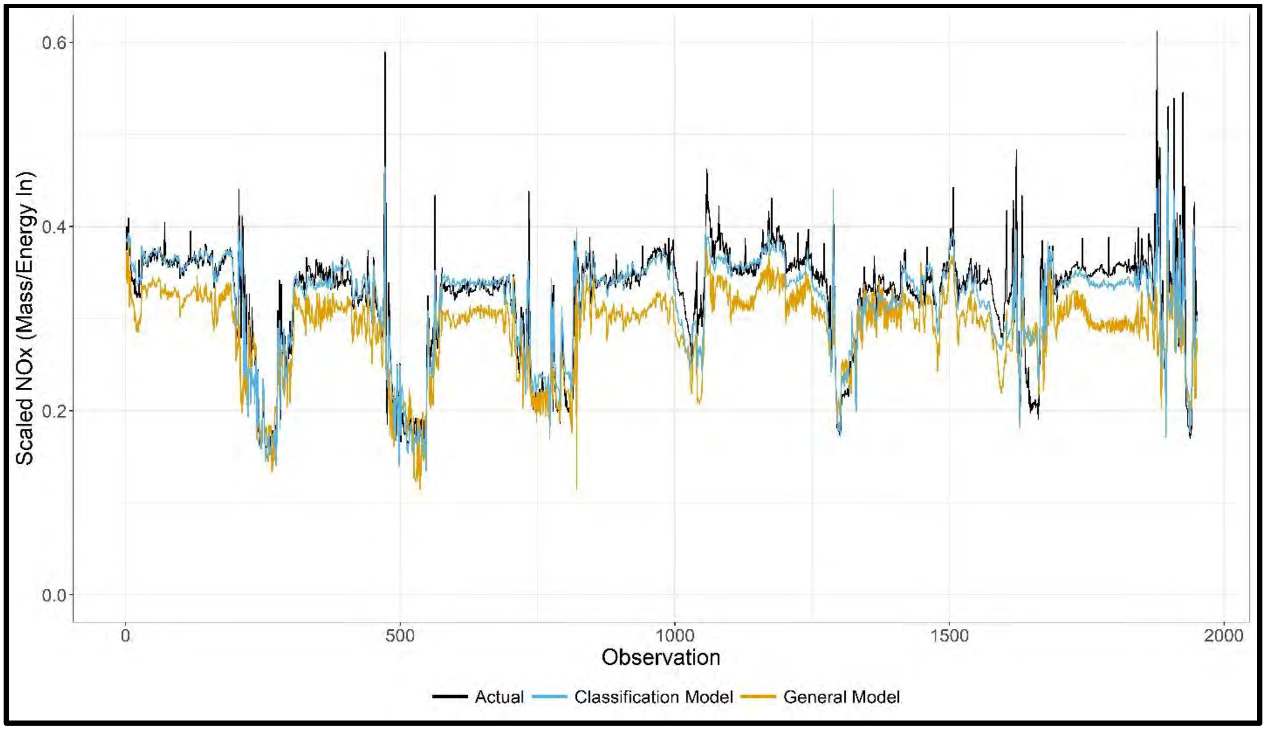

Figure 20 - Improved prediction ability of SVM classification neural network model (blue) against previously existing neural network model (orange)

Cooling Tower Control: Optimization of cooling tower performance was performed in a two-part study, consisting of a simulation study followed by closed-loop development within an application onsite. A simulation study was performed first for two main reasons: to evaluate potential auxiliary power benefits from optimization of cooling tower fan speeds and to "jump-start" the training of a neural network model for use onsite at the plant with data generated from theoretical relationships based in heat and mass transfer. To first identify if the existing DCS assumption of identical performance of each cooling tower cell was valid or not, data obtained from the plant of individual fan power use was analyzed. Figure 21 shows the effect which load changes and ambient temperature have on each cell's power draw. It can be easily seen that the performance of each fan changes with load and ambient temperature, so much as to effect which cells operate more efficiently as load moves. These large changes in power usage verify that the individual cells are certainly not identical, and there is likely benefit to be gained from optimization of individual fan speeds.

A theoretical simulation model of the station's 12-celled cooling tower was created and used as proxy for the physical tower during the initial analysis. The potential major benefits of optimization lie in exploiting efficiency differences between each cell, so within the physical model each cell was assigned a varied efficiency factor to better replicate the performance found in the data. This model is displayed as Figure 22.

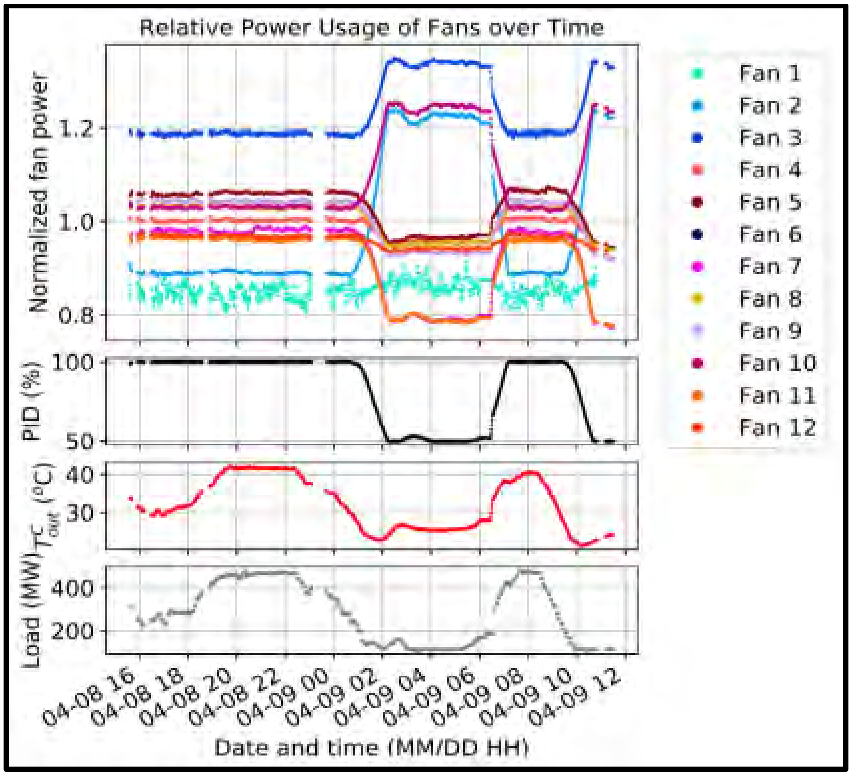

Figure 21 – Power consumption of individual cooling tower fans

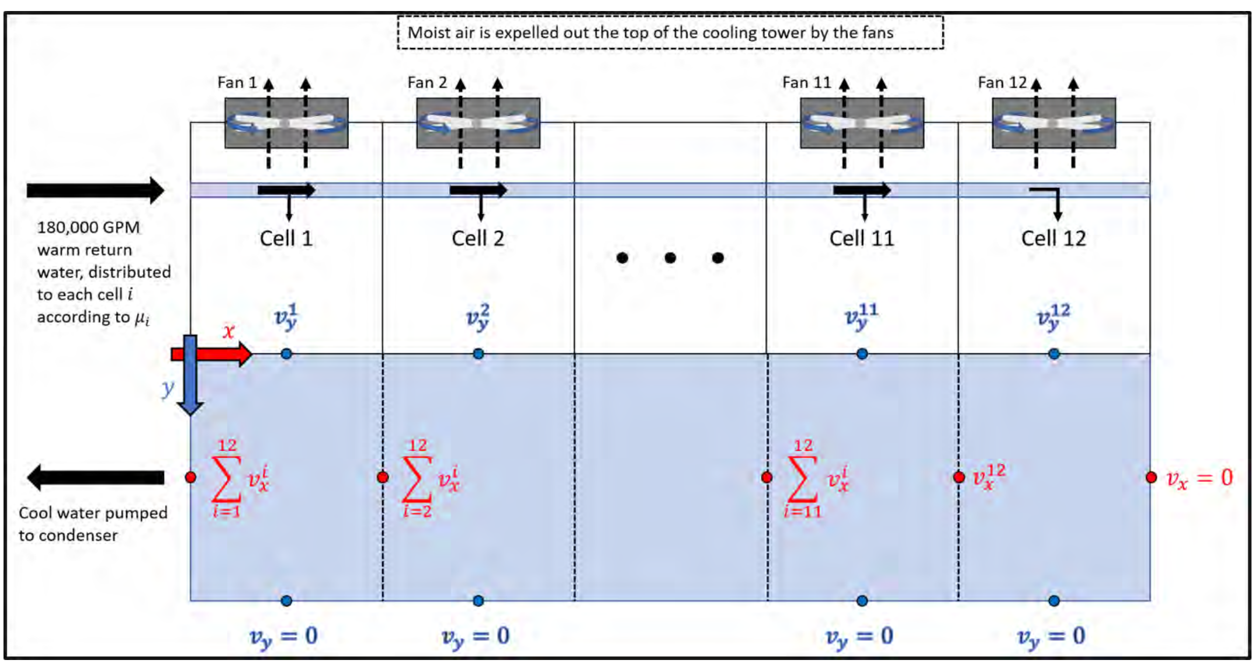

Figure 22 – Physical model of cooling tower cells

A neural network was trained from the power usage and cooling results obtained from the simulation model. The neural network demonstrated a high degree of accuracy, as shown in Figure 23. With the trained neural network, the system was allowed to "self-generate" varied data, meaning the neural network was allowed to vary fan speeds as determined by optimizing the neural network results within the simulation model to generate data across the operational space and to assess the potential benefits from optimization. This process is shown in Figure 24.

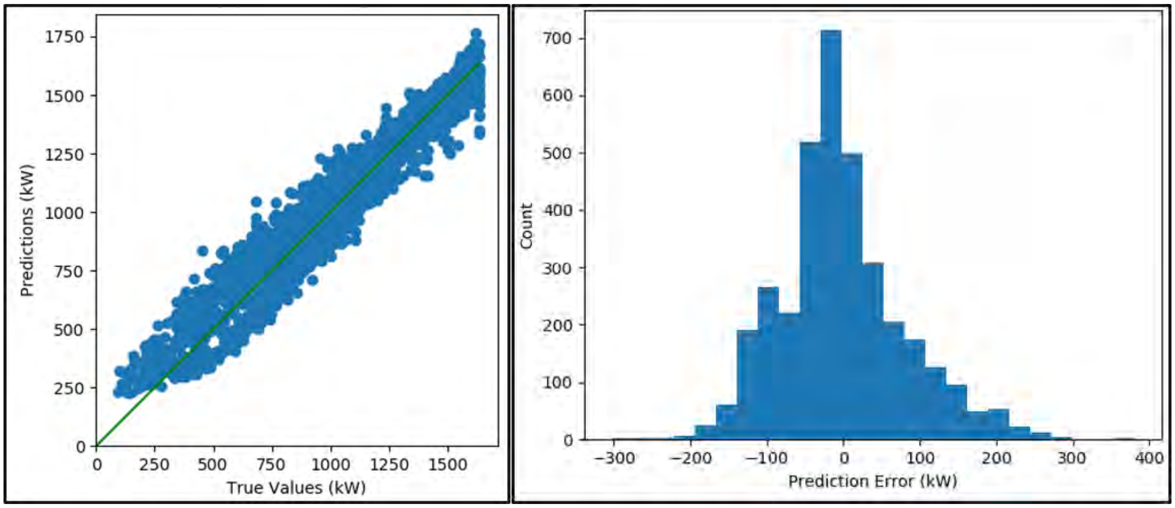

Figure 23 – Neural network results compared to actual values and histogram of prediction error

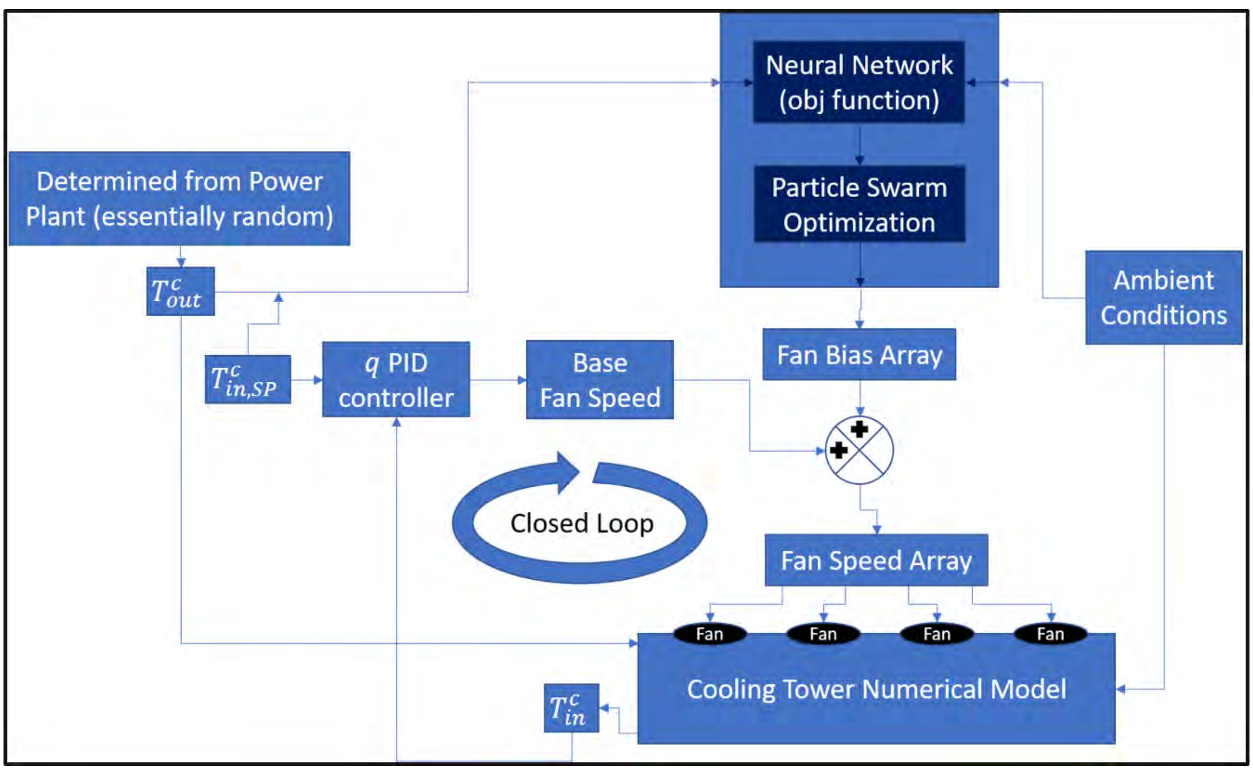

Figure 24 – Diagram of closed-loop simulation neural network optimization

Results of this simulation analysis are displayed in Figure 25 and Figure 26. A potential cost savings due to optimization of individual fan speed setpoints greater than 10% was estimated through this analysis. These results confirmed that closed-loop development onsite at the power plant was warranted and could be expected to generate benefits in power consumption, heat rate, and ultimately cost savings.

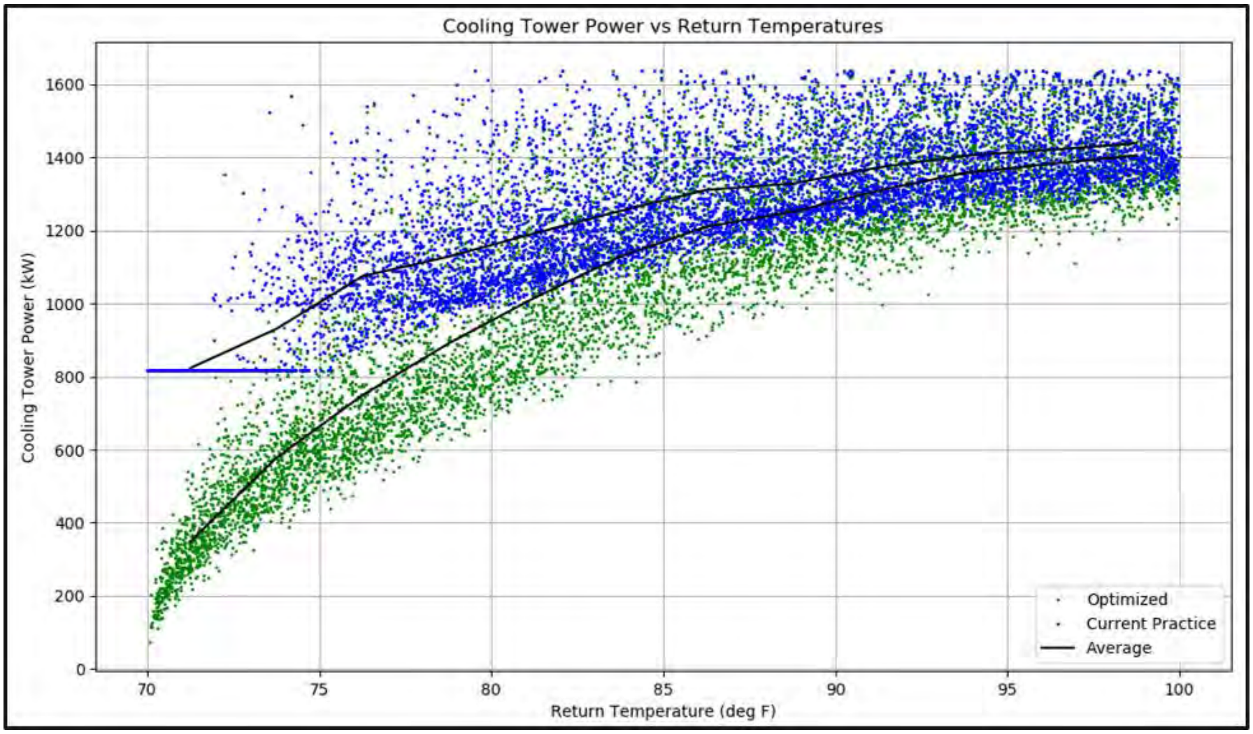

Figure 25 – Directly measured and optimized within simulation total cooling tower power usage

	Current Practice	Remove 50% fan floor	Optimize
Total Energy (kWh)	10,797,520	10,575,760	9,619,067
Total Cost	$669,446	$655,697	$596,382
Savings (%)	-	2.05%	10.91%
Savings ($)	-	$13,749	$73,064

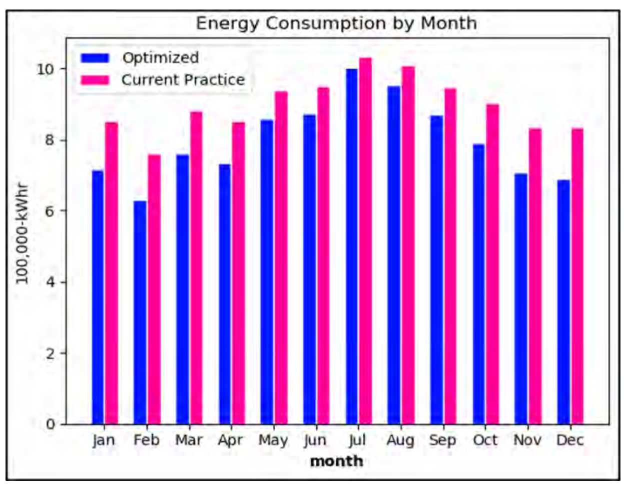

Figure 26 – Calculated cost savings and energy consumption by month using current practices and optimization

Onsite development of the cooling tower optimization application was completed on August 27th, 2019. Before this, operators were asked to manually adjust individual fan setpoints on the unit to help generate a varied dataset for the neural network model to be trained from. Operators was very willing to help with this, and their cooperation has been greatly appreciated and helped to make this study effective.

The developed system functions very similarly to the existing COS application, being governed and limited by multiple biasing limits from DCS setpoint as well as limits on the final position of parameter setpoints. The actual implementation within the DCS is slightly different, as the existing control hardware does not accept biases, so direct fan setpoints are written from the Griffin system to the individual cooling tower fans.

A direct measurement of fan power usage is not available within the DCS, however since power is related to amperage according to

$$P = V * A * constant$$

and the volts of each fan are identical and constant and the constant value is constant, minimization of amperage is effectively minimization of power consumption, and amperage is what is considered by the neural network model and focused on by this application.

Between onsite development and the outage in October 2019, the optimization application was activated by individual operators at various times. A comparison of measured total amps of the cooling tower fans while the application was active and inactive within each 10 MW bin across the unit's load range shows that on average cooling tower fan speed optimization achieved a 5.2% reduction in cooling tower power consumption, as shown in Figure 27. At the three load ranges where the majority of plant operation and optimization use were seen (140 – 150, 460 – 470, and 470 – 480 MW) the weighted average benefit was 6.9%, due mostly to the large improvement observed at lower load. It can be seen within Figure 27 that the observed optimization benefit during this time period decreased significantly at loads greater than 400 MW. It can be concluded that as these higher loads were reached and fan speeds approached maximum to meet cooling demands of the unit, that the cooling tower is required to operate at full capacity. This observation is positive from the viewpoint of the cooling tower application, as it demonstrates that the base cooling tower function of meeting cooling demand and achieving appropriate turbine exhaust pressures is prioritized over power consumption minimization, ensuring that the system is robust and safe for constant use.

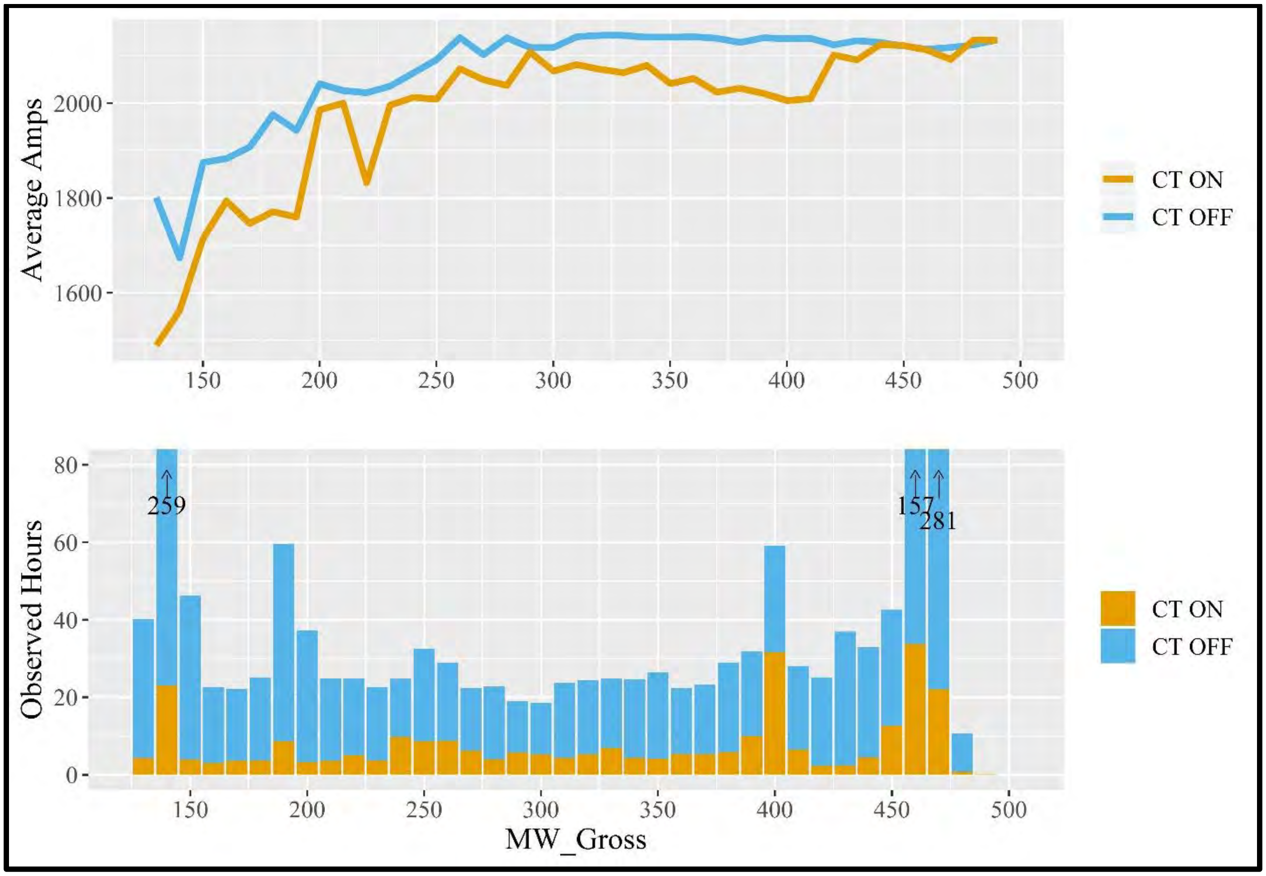

Figure 27 – Onsite cooling tower optimization system performance in closed-loop at power plant and observed hours at each generation level

System Adoption

Early on in the project, the single largest factor which affect service factor of the system was operator's relationship with the system. Often times, many operators being unfamiliar with the system and it's use, would simply forget it was there and not turn it on if it was not already on. As well, in many instances a circumstance would arise with an unrelated piece of equipment, and the system would be turned off to address that problem. It was then never turned back on until research team members asked the current operator if it could be reactivated. This factor did decrease overtime with the constant onsite presence of the research team and continual training and answering of questions which operations had of the system's behavior. However, at the project's close, this circumstance of operator oversight was still being observed to a small degree.

Overall, the system was well received by operations. Many operators expressed that they were pleased with how the Griffin optimizer handled most commonly encountered situations, and when it was not performing well due to uncommon circumstances, they would disengage the system until the condition was resolved, then reengage the system afterward.

The strong working relationship between the research team and operations was a major factor contributing to overall system adoption and use. Operations having the ability to "recognize a face" associated with the system and having a person to discuss problems and ask questions to was indispensable in making this project a success and seeing the system used continually. This helped operators to develop trust in the system, and to also recognize that if any aspect of the system did not perform, it could be addressed and fixed by simply discussing the matter with the research team.

A major example of this was the development of the SOFA Tilt controller to aid with managing tube temperatures during QIII 2018. Operations had voiced to the research team that they had been struggling for an extended period of time with seeing measured tube temperatures exceed desired levels. Working closely with the operators, the research team was able to identify the relationship of SOFA tilts to decreasing tube temperatures, and quickly constructed a controller to exploit this relationship.

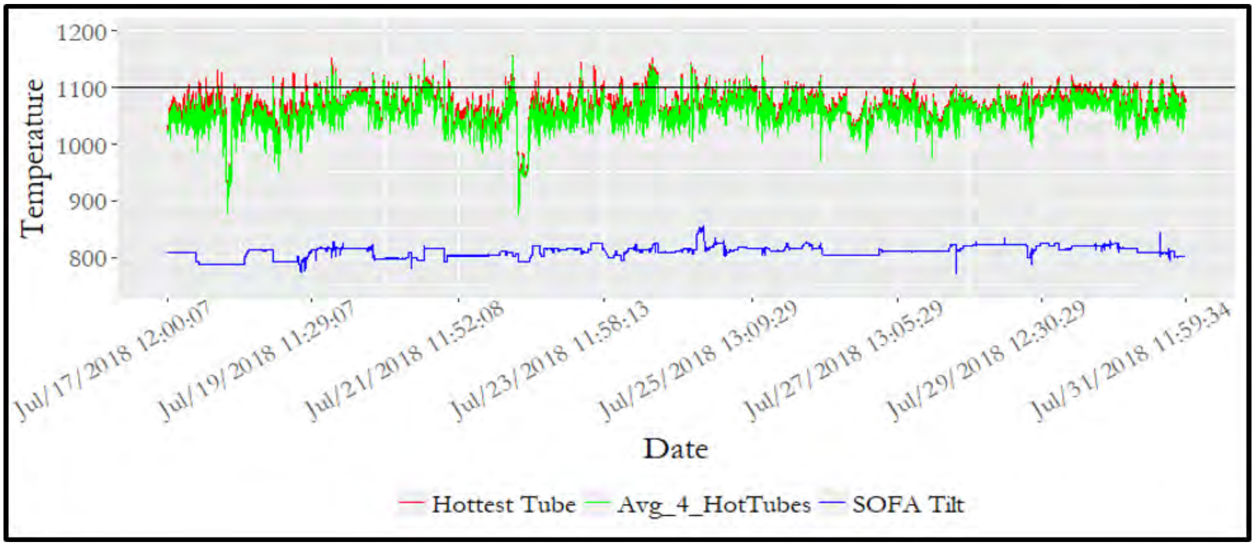

Figure 28 – Observed hottest tube temperature and average of hottest four tubes for one month prior to SOFA tilt control being developed

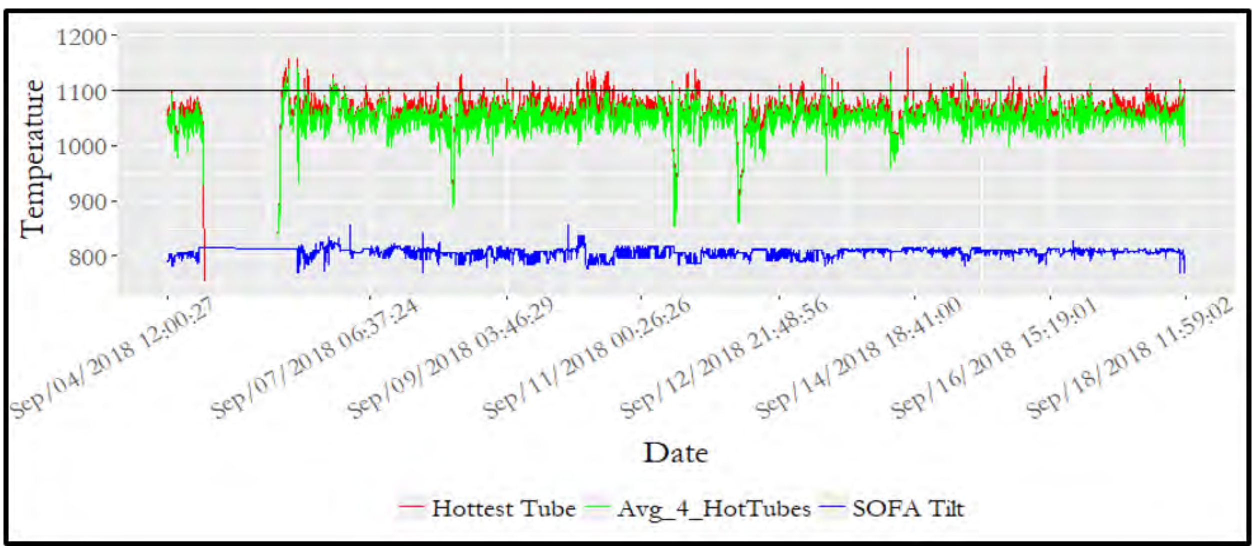

Figure 29 - Observed hottest tube temperature and average of hottest four tubes for one month with SOFA tilt control active

Figures 28 and 29 show the observed hottest tube temperature and the average of the hottest four tubes for one month before and for one month with the newly developed SOFA tilt control active. The average of the hottest four tubes was considered a more reliable indicator of tube temperatures, as the single hottest tube measurement was seen to behave erratically at times. The simple control methodology of automatically lowering the lower SOFA tilts proportionally to the elevated four tube average temperature was able to drastically reduce the amount of time which these tubes were observed to exceed desired levels, by more than 87%.

Table 6 – Observed time of high tube temperatures before and with control within the Griffin COS

	Hottest Tube Above Target	Hottest 4 Tube Average Above Target
Before Control	39.8 hrs	21.4 hrs
With Control	18.9 hrs	2.4 hrs
Percent Change	-46.2%	-87.2%

This one development was observed to contribute to a significant increase in service factor during QIII 2018 and subsequent quarters of the project, from 54% during QII 2018 to 80% during QIII. Situations such as this where operations was able to express issues and problems to the research team and see direct positive impacts of changes made to the optimization system played a large role in overall system adoption and project success.

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Calculated Data for NOx, CO, and Cooling Tower Amps Across Load Range:

MW Bin	Average NOx (lbs/MMBtu)			
	Baseline	2017	2018	2019
100 – 110	N/A	N/A	N/A	0.147
110 – 120	0.215	0.219	0.189	0.144
120 – 130	0.205	0.209	0.148	0.151
130 – 140	0.158	0.161	0.140	0.142
140 – 150	0.171	0.164	0.129	0.136
150 – 160	0.159	0.156	0.124	0.142
160 – 170	0.163	0.163	0.126	0.150
170 – 180	0.168	0.169	0.134	0.154
180 – 190	0.179	0.181	0.146	0.167
190 – 200	0.182	0.198	0.157	0.171
200 – 210	0.186	0.205	0.169	0.187
210 – 220	0.196	0.209	0.176	0.199
220 – 230	0.198	0.212	0.177	0.195
230 – 240	0.199	0.214	0.177	0.190
240 – 250	0.204	0.213	0.176	0.184
250 – 260	0.205	0.209	0.174	0.183
260 – 270	0.205	0.206	0.172	0.179
270 – 280	0.207	0.200	0.169	0.179
280 – 290	0.205	0.199	0.168	0.175
290 – 300	0.208	0.199	0.168	0.181
300 – 310	0.209	0.199	0.172	0.181
310 – 320	0.210	0.200	0.173	0.183
320 – 330	0.211	0.204	0.176	0.182
330 – 340	0.212	0.205	0.178	0.189
340 – 350	0.216	0.208	0.179	0.189
350 – 360	0.215	0.211	0.183	0.192
360 – 370	0.217	0.213	0.188	0.194
370 – 380	0.218	0.215	0.189	0.194
380 – 390	0.218	0.216	0.192	0.195
390 – 400	0.221	0.219	0.192	0.194
400 – 410	0.221	0.220	0.197	0.196
410 – 420	0.223	0.224	0.201	0.209
420 – 430	0.225	0.224	0.201	0.206
430 – 440	0.224	0.222	0.198	0.207
440 – 450	0.223	0.222	0.199	0.206
450 – 460	0.225	0.226	0.206	0.213
460 – 470	0.232	0.231	0.213	0.223
470 – 480	0.233	0.226	0.205	0.212
480 – 490	0.239	0.222	0.197	0.206
490 – 500	0.253	N/A	N/A	0.221
500 – 510	N/A	N/A	N/A	0.205

MW Bin	Average CO (PPM)			
	Baseline	2017	2018	2019
100 – 110	N/A	N/A	N/A	12
110 – 120	120	120	20	15
120 – 130	11	9	15	43
130 – 140	20	19	32	53
140 – 150	48	47	69	70
150 – 160	71	67	105	96
160 – 170	95	91	125	127
170 – 180	118	107	124	139
180 – 190	115	101	108	119
190 – 200	116	85	104	105
200 – 210	130	98	98	101
210 – 220	128	101	86	89
220 – 230	142	96	92	104
230 – 240	152	94	86	111
240 – 250	192	118	87	114
250 – 260	165	117	97	102
260 – 270	202	147	92	105
270 – 280	194	144	107	103
280 – 290	216	154	120	107
290 – 300	225	162	120	117
300 – 310	236	161	125	105
310 – 320	258	155	120	107
320 – 330	238	149	113	114
330 – 340	243	119	114	97
340 – 350	244	135	102	108
350 – 360	256	151	102	112
360 – 370	251	148	99	105
370 – 380	259	144	101	112
380 – 390	258	156	100	115
390 – 400	239	142	105	127
400 – 410	235	145	101	105
410 – 420	236	152	97	115
420 – 430	242	186	109	137
430 – 440	242	184	123	164
440 – 450	229	184	131	175
450 – 460	249	155	141	164
460 – 470	238	137	130	142
470 – 480	233	164	123	184
480 – 490	430	204	141	228
490 – 500	473	N/A	N/A	299
500 – 510	N/A	N/A	N/A	196

MW Bin	Average Cooling Tower Amps		Observed 5 minute Increments	
	Griffin On 2019	Griffin Off 2019	2018	2019
100 – 110	2213	978	1	3
110 – 120	N/A	1466	N/A	5
120 – 130	2202	1846	1	36
130 – 140	1490	1801	51	482
140 – 150	1563	1674	277	3109
150 – 160	1715	1875	47	556
160 – 170	1794	1883	37	271
170 – 180	1747	1908	43	266
180 – 190	1771	1976	44	302
190 – 200	1760	1943	104	715
200 – 210	1986	2041	39	446
210 – 220	2000	2026	43	298
220 – 230	1832	2022	60	299
230 – 240	1996	2036	44	272
240 – 250	2012	2064	117	297
250 – 260	2008	2092	104	391
260 – 270	2072	2138	105	346
270 – 280	2050	2102	75	268
280 – 290	2037	2138	48	273
290 – 300	2107	2117	69	227
300 – 310	2068	2117	63	223
310 – 320	2081	2140	52	284
320 – 330	2072	2143	63	292
330 – 340	2064	2143	83	298
340 – 350	2080	2139	52	296
350 – 360	2041	2139	50	318
360 – 370	2052	2140	64	268
370 – 380	2023	2137	64	279
380 – 390	2031	2128	70	347
390 – 400	2020	2138	120	385
400 – 410	2006	2136	379	709
410 – 420	2009	2137	78	337
420 – 430	2102	2123	28	302
430 – 440	2091	2132	29	443
440 – 450	2124	2128	54	395
450 – 460	2121	2121	152	511
460 – 470	2112	2114	405	1881
470 – 480	2092	2118	265	3377
480 – 490	2133	2123	9	127
490 – 500	2132	2133	2	2

STEP Project Report

Period Ending: December 31, 2019

STEP Project Name: Alternative NO_X Reduction (PROJECT CANCELED)

Project Objective:

The project was designed 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 was 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 Cancelation:

The Alternative NOx Project, which was approved on May 24, 2017, commenced with issuing a request for information from technology providers. The results of the technical and commercial proposals showed that none of the vendors would be able to meet the project's criteria for a cost-effective and innovative technology for a demonstration test. Each of the vendor proposals were outside the project's budget or proposed a technology that was known and established. Rocky Mountain Power concluded, based on the results of the Request for Proposals ("RFP"), that the STEP funding would be better utilized in furthering other Clean Coal Research projects already approved by the Commission over demonstrating a non-innovative NOx control technology with a known emission reduction capability. The Company communicated the proposal to abandon the project in the March 12, 2018, STEP Project Update meeting, and it was also included in the First STEP Annual Report in Docket No. 18-035-16 ("STEP Report Docket"). On November 13, 2018, the Company requested approval to reallocate the remaining unspent funds, a total of $1,161,501, from the Alternative NOx project to the Co-Firing Test of Woody-waste Materials at Hunter Unit 3 and the Croygenic Carbon Capture projects. The Commission approved the request on February 6, 2019. The Company will continue to submit a project report for the canceled Alternative NOx project, although no additional spend or project milestones will occur beyond what is reported below for 2018. The 2018 funds were spent in early 2018 prior to the project's cancellation on the outside services of an owners engineer as part of the evaluation of the RFP.

Project Accounting:

	2017	2018	2019	Total
Annual Collection (Budget)	$125,000	$0	$0.00	$125,000
Annual Spend (Capital)	$0.00	$0.00	$0.00	$0.00
Committed Funds	$0.00	$0.00	$0.00	$0.00
Uncommitted Funds	$0.00	$0.00	$0.00	$0.00
External OMAG Expenses	$131,405	$26,010	$0.00	$157,415
Subtotal	$131,405	$26,010*	$0.00	$157,415

*In the Company's Application to Modify Funding Amounts Previously Authorized by STEP filed on November 13, 2018, in Docket No. 16-035-36, paragraph 19 of the Application stated that a total of $170,356 had been spent on the Alternative NOx project for the RFP and owner's engineer services. This amount included $131,405 in CY 2017 expenses and $38,951 in CY 2018 expenses. The $38,951 in CY 2018 included an accounting accrual of which $12,941 was subsequently reversed. The total for CY 2018 is $26,010. Also in paragraph 19, the Company requested $1,161,501 be transferred to the other clean coal projects, leaving $89,964 unallocated. With the revision in CY 2018 expenses, the unallocated amount is revised as follows:

Original budget for the Alternative NOx Project	$1,415,821
Funds spent on Alternative NOx Project	$157,415
Funds transferred to other clean coal projects	$1,161,501
Unallocated funds	$96,905

Project Milestones:

Project Milestone	Delivery Date	Status
Kick off meeting	March 30, 2017	Complete
Draft version of RFI for Alternative NOx Technologies	May 18, 2017	Complete, draft received on May 1, 2017
Issue RFI for Alternative NOx Technologies	May 29, 2017	Completed
RFI Response Due	June 22, 2017	Completed
Summary of RFI Response	August 6, 2017	Completed
Issue RFP for Alternative NOx 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)
Project Cancellation	June 30, 2018	Complete
Funding Reallocation to Other STEP Clean Coal Projects	December 31, 2018	Complete

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.

STEP Project Report

Period Ending: December 31, 2019

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

Project Objective:

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

Project Accounting:

Cost Object	2017	2018	2019	Total
Annual Collection (Budget)	$0.00	$62,500	$42,133	$104,633
Annual Spend (Capital)	$0.00	$0.00	$0.00	$0.00
Committed Funds	$0.00	$0.00	$0.00	$0.00
Uncommitted Funds	$0.00	$0.00	$0.00	$0.00
External OMAG Expenses*	$0.00	$73,041**	$42,133	$115,174
Subtotal	$0.00	$73,041	$42,133	$115,174

* External OMAG for 2018 and 2019 was for contractual payments to the University of Utah for the feasibility study they provided on the project.

**The amount reported in the 2018 STEP report, $94,029 was the amount of original committed funds, but has been updated to reflect the actual amount spent of $73,041.

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	Completed
Annual Report 1 Presented and Submitted	January 31, 2019	Completed
Annual Report 2 Presented and Submitted	January 31, 2020	Completed
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 study will give us more knowledge on the technical, economic, and environmental effects of injecting coal-fired-power-plant-derived CO_2 into underground coal beds for enhanced methane recovery. The study will also determine whether the Emery County coal beds are conducive to enhanced methane recovery using CO_2. Deliverables will include an evaluation of the technologies and strategies for improving CO_2 injection efficiency. The University of Utah will also study the risk of induced seismicity due to CO_2 injection.

Depending on the results of the study, Rocky Mountain Power's customers may ultimately benefit through increased efficiency of energy production with less CO_2 emissions. When the benefits of the study are combined with other studies and work being conducted under the STEP program, applicable real-world knowledge will be gained about the risks, costs, and benefits of carbon sequestration.

Key Challenges, Finding, Results and Lessons Learned:

Key Challenges	Results / Progress
Task 1: Resource Evaluation: Identification and selection of a coal resource to be studied for volumetric CO_2 storage	a) Drill logs have been digitalized for coal resource identification b) Stratigraphic Coal Units have been identified from well logs. Six coal units have been identified. From wireline logs and production records obtained from the Utah Department of Oil, Gas and Mining (DOGM) website, the producing zones in the northern section of the Buzzard Bench Field coalbeds were identified -clustered- as ‘Upper’, ‘Middle’ and ‘Lower’. c) The coal units’ geological structure was delineated by identifying the top of the Ferron Sandstone, which is identifiable on each well log, and mapping in fence diagrams to observe the depth variation of the coal units along the Buzzard Bench Field. d) The data gathered from the geological structure of the coal units was used to develop a three-dimensional model of the study area. e) The model is complete the data and is being utilized to estimate the amount of CO2 that could be stored.
Task 2: Bench Scale Demonstration:	a) The test apparatus was designed and constructed in 2019. Shake down tests of various materials began in late 2019. Coal sample testing is planned for 2020.

Potential future applications for similar projects:

When combined with the results of the STEP CarbonSAFE project and the STEP Cryogenic Carbon Capture program, Rocky Mountain Power would have sufficient experience with these technologies to develop a strategy for carbon sequestration in Utah. Additionally, information gathered from the study can be utilized to develop further understanding of potential enhanced energy recovery in Utah with simultaneous sequestration.

Cryogenic Carbon Capture - STEP Project Report

Period Ending: December 31, 2019

STEP Project Name: Cryogenic Carbon Capture (CCC) Demonstration (Emerging CO_2 Capture)

Project Objective:

The objective of this project is to continue the development and demonstration of promising CCC technology.

The scope of work is divided into two primary phases. The first, called the Development Phase, involves research to be performed by a contractor into specific areas where it is believed efficiency, reliability, or overall performance of the CCC process can be improved. Rocky Mountain Power (RMP) contracted with Sustainable Energy Solutions (SES) to do this work. SES's recommendations and experimental results were used to make changes and enhancements to the skid demonstration unit provided as part of this Scope of Work. On-site preparations by SES and RMP personnel of the testing area at the Hunter Power Plant in central Utah were completed in 2019. The Field Demonstration Phase used the demonstration unit at the site during an extended test run over approximately six months. SES's development work took place during 2017 and early 2018 with the field testing beginning in early 2019.

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

In Docket No. 16-035-36, the Commission approved the Company's request to increase funding for the Cryogenic Carbon Capture project by $412,521, utilizing funds from the cancelled Alternative NOx project. With these additional funds, the Company expanded the scope to plan for the next scale of CCC operation to explore the scalability of these and related unit operations as part of this investigation. This project includes one task for each of three major systems. These systems require major changes to the current skid operation in contrast to the incremental changes supported by the current Department of Energy project. The additional milestones have been added to this report.

The project includes an economic assessment of utility-scale implementation of technology. In 2019 RMP hired Sargent & Lundy to deliver a report assessing the scalability of SES's technology to a size capable of processing all exhaust flue gas from one or more existing coal fueled thermal generation power plants owned by RMP.

Project Accounting:

Cost Object	2017	2018	2019	Total
Annual Collection (Budget)	$356,557	$668,301	$412,521	$1,437,379
Annual Spend (Capital)	$0.00	$0.00	$0.00	$0.00
Committed Funds	$0.00	$0.00	$0.00	$0.00
Uncommitted Funds	$0.00	$0.00	$0.00	$0.00
External OMAG Expenses*	$160,451	$530,289	$711,750	$1,402,490
Subtotal	$160,451	$530,289	$711,750	$1,402,490

*External OMAG consists of contractual payments to Sustainable Energy Solutions for services performed on the project. A description of these services is described in the project milestone section below.

Project Milestones:

Project Milestone	Delivery Date	Status
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 CO_2 - 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 heat exchangers, 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.	11/20/2018	Completed
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	Completed
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.	2/26/2019	Completed
SES will deliver a report containing the following: **Task A1** – Finalized integrated dryer design. Results of experiments used to validate design. Equipment sourced. **Task A2** – Final selection of the solid-liquid system, or other system designed to meet the same requirements, which will be tested. Initial long lead time parts ordered. Assessment of pollutant removal options and modeling of basic design of system.	4/15/2019	Completed
SES will deliver a report containing the following: **Task A1** – Record of dryer system equipment being ordered. **Task A2** – Finalized design and record of system ordered. Description of assembled solid-liquid or other separation system. Designs and parts ordered for the pollutant removal system.	7/15/2019	Completed
SES will deliver a report containing the following: **Task A1** – The receipt of the system and initial results of both assembly and dryer testing. **Task A2** – Results of initial testing and subsequent iteration on solid-liquid or other separations system. Description of assembled pollutant removal system.	10/15/2019	Completed

SES will deliver a report containing the following: **Task A1** – Results of further test results including using real flue gas and initial integration with skid system. Final Reporting. **Task A2** – Results of testing the finalized designs. Final Reporting. **Task A3** – Assessment of scale-up potential of innovative unit ops including dryer and solid-liquid separations.	1/15/2020	Completed
Sargent & Lundy scalability study assessing the scalability of the technology for complete processing of flue gas at utility power plants.	7/1/2020	On Schedule

Program Benefits:

This program will help us determine the economic feasibility of CCC technology. The technology shows promise in being able to reduce CO_2 emissions. The demonstration test would allow the Company to evaluate the ability of SES's CCC technology to meet these goals.

The added milestones provide for modifications which improve the reliability and in some cases, decrease the energy and economic costs of the process.

Potential Future Applications:

SES has applied for U. S. Department of Energy ARPA-e funding. Utah State funding has been approved for a larger SES CCC scale-up project which may be hosted at one of PacifiCorp's plants.

STEP Project Report

Period Ending: December 31, 2019

STEP Project Name: CarbonSAFE Pre-Feasibility Study – Phase 1 (Sequestration Site Characterization) COMPLETE

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	2018	2019	Total
Annual Collection (Budget)	$150,000	$0.00	$0.00	$150,239
Annual Spend (Capital)	$0.00	$0.00	$0.00	$0.00
Committed Funds	$0.00	$0.00	$0.00	$0.00
Uncommitted Funds	$0.00		$0.00	$0.00
External OMAG Expenses	$150,239	$0.00	$0.00	$150,239
Subtotal	$150,239	$0.00	$0.00	$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	Completed

Final Report Presented and Submitted	May 2019	Completed

Key Challenges, Findings, Results and Lessons Learned:

Description of Investment

STEP funding for this project was used to support a pre-feasibility study of carbon dioxide (CO_2) capture and sequestration capabilities in the intermountain west. 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 CO_2 storage reservoir. The summary provided below is taken from the Carbonsafe Rocky Mountain Phase I: Ensuring Safe Subsurface Storage Of Carbon Dioxide In The Intermountain West Final Report (Attachment A).

Anticipated Outcome

- Determine if central Utah's geological formations were suitable for storing up to 50 million metric tons (tonnes) of CO_2 in a saline aquifer.
- Identify a study area that could be utilized by Utah's existing coal-fired facilities.
- Identify the commercial and non-techncial challenges in developing a CO_2 storage aquifer.
- Provide a template protocol for future and existing coal-fired and gas-fired facilities that could be utilized for further development of a CO_2 storage aquifer.

Challenges

- Four key challenges were identified in pre-feasiblity study. These challenges are:
  - Cost and cost recovery of construction and operation CO_2 capture and sequestration (CCS) infrastructure;
  - the lack of price signal or financial incentive for developing, construction and operation of a CCS;
  - liability risks associated with the storage aquifer, including legacy liability; and
  - an overall lack of a comprehensive CCS regulation.
- Additional challenges recognized were:
  - Overall lack of CCS regulatory framework; and
  - lack of historical cost information to implement and operated CCS.

Findings / Results

- Capture assessments were performed using both commercial and emerging technologies to capture approximately 2.75 million tonnes per year for one of the boiler units at the Hunter Power Plant. The estimates showed that the:
  - Amine based (commercial technology) system cost of capture was estimated of 45.50/tonne.
  - The cryogenic based (emerging technology) cost of capture was estimated at $37.75/tonne.

- Compression of the captured CO_2 and transportation, via high pressure pipeline, would increase the cost per tonne. The cost would be highly dependent on the specific injection location and rights of way and therefore not estimated in the pre-feasibility study.
- The area around the Hunter and Huntington Power Plants were subject of a high-level technical sub-basinal evaluation to verify CO_2 storage capacity and integrity. The result of the evaluation showed potential injection sites might be available, into the high permeability (~200 mD) and high porosity (20%) Navajo sandstone in the Buzzards Bench area of central Utah.
- A comprehensive analysis of the proposed reservoir and seals was conducted and a 3-dimensional model was created. Simulation and risk assessment on the proposed site were conducted. The findings showed that the CO_2 capacity estimates for the Navajo Sandstone, approximately 18 kilometers from the Hunter plant, are well in excess of the 50 million tonnes goal of the project.
- Non-technical assessments for a commercial-scale CO_2 storage facility in central Utah was conducted. The Environmental Protection Agency's Underground Injection Control Class VI and National Environmental Policy Act permitting present particular challenges in developing a saline aquifer for CO_2 storage. Surface and subsurface ownership and rights are also not straight forward and would need to be resolved if any storage facility would be constructed. Most critically is the legacy ownership and risk of a CO_2 storage facility.

Lessons Learned

- Some critical lessons learned and challenges that were identified in the study were:
    - Lack of clarity of pore space ownership – Utah does not have a clear precedent on who would own the subsurface pore space for CO_2 storage.
    - Commercial operation capital cost, operations and maintenance cost and regulatory recovery – Further work is needed to determine if regulatory approval for PacifiCorp could be obtained to construct and CCS facility. Challenges identified include PacifiCorp's six state operations and differing regulatory requirements.
    - Permitting a CO_2 capture and storage facility – There is not a clear process in which an entity could permit a CO_2 capture and storage facility. History of previously permitted facilities were reviewed and each faced numerous challenges, environmental approvals and public comments.
    - Brine and waste disposal – Since brine would be created from the saline aquifer and cannot be used for enhanced oil recovery another method must be used for disposal. Methods such as evaporation face their own environmental challenges and would increase cost and risk of a storage facility

Program Benefits

The participation into the study has resulted in a high level cost estimate as to the cost to construct a CO_2 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 CO_2 capture is feasible in Utah. The University of Utah to the Department of Energy final report is provies a detail insight as to the challenges in constructing a CCS facility.

Attachments:

(Note: the attachment is voluminous and is provided as a separate attachment)

Exhibit 8-A CARBONSAFE ROCKY MOUNTAIN PHASE I: ENSURING SAFE SUBSURFACE STORAGE OF CARBON DIOXIDE IN THE INTERMOUNTAIN WEST

CARBONSAFE ROCKY MOUNTAIN PHASE I: ENSURING SAFE SUBSURFACE STORAGE OF CARBON DIOXIDE IN THE INTERMOUNTAIN WEST

Final Report

Reporting Period: March 1, 2017 to August 31, 2018

DE-FE0029280

Submitted by

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DISCLAIMER

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EXECUTIVE SUMMARY

An integrated CCS pre-feasibility study, CarbonSAFE Rocky Mountain Phase I, was conducted by the University of Utah and its partners as part of the US Department of Energy's Carbon Storage Assurance and Facility Enterprise (CarbonSAFE) program. The assembled project team consisted of academic, industry and governmental agencies covering the technical and non-technical challenges of a commercial-scale CO_2 storage facility capable of storing 50 million tonnes of anthropogenically-sourced CO_2.

The Rocky Mountain CarbonSAFE team identified the Hunter Power Plant in central Utah as the primary source of CO_2 on which this study would be focused. The nearby Huntington power plant, also operated by Rocky Mountain Power, was evaluated as a secondary source of CO_2. The Hunter plant was chosen because of an interest in CO_2 capture technology by the plant operator, Rocky Mountain Power, and also because it is a representative example of a typical coal-fired generating station in the Rocky Mountain west. Amine-based and cryogenic-based capture assessments were performed for approximately 2.75 million tonnes per year for one of the boiler units at the Hunter plant, yielding cost of capture estimates of $45.50/tonne and $37.75/tonne. Transportation and intermediate compression would increase the per tonne costs, but will be highly dependent on specific injection locations and available rights-of-way.

A high-level technical sub-basinal evaluation was performed on the area surrounding the Hunter and Huntington power plants to verify CO_2 storage capacity and integrity. Initial geologic characterization efforts focused on sites immediately adjacent to the Hunter plant, including the deep eolian Permian White Rim Sandstone, which in outcrop and core from other locations indicates high permeability and high porosity. However, petrophysical logs from wells near Hunter indicate porosity of only 2-4%. As a result, potential injection sites were moved structurally down-dip (to the west), into the high permeability (~200 mD) and high porosity (20%) Navajo sandstone. A comprehensive analysis of the reservoir and seals was conducted, providing data to the model, simulation and risk assessment groups on the project. CO_2 capacity estimates for the Navajo Sandstone approximately 18 kilometers from the Hunter plant are well in excess of the 50 million tonnes goal of the project. Area of Review Delineation and Risk Assessment on the Navajo, associated seals and shallow groundwater aquifers identified the most significant risks and mitigation options.

A non-technical assessment to a commercial-scale CO_2 storage facility in central Utah was conducted. EPA Underground Injection Control Class VI and National Environmental Policy Act permitting present particularly challenging issues related to the development of any saline aquifer for CO_2 storage, including the area around the Hunter plant. While surface and subsurface ownership and rights are not straightforward, especially on any private land, many of the stakeholders in central Utah are accustomed and open to oil/gas/mineral-related activities similar to what would be required for CO_2 storage sites.

Acronyms

ADM	Archer Daniels Midland
AoR	Area of Review
AQCS	Air Quality Control Systems
BLM	Bureau of Land Management
CCS	Carbon Capture and Sequestration
CE	Categorical Exclusion
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CFR.	Code of Federal Regulations
CO2	Carbon Dioxide
DEIS	Draft Environmental Impact Statement
DOE	United States Department of Energy
EA	Environmental Assessment
EIS	Environmental Impact Statement
EOR	Enhanced Oil Recovery
EPA	United States Environmental Protection Agency
ESA	Endangered Species Act
FEIS	Final Environmental Impact Statement
FLPMA	Federal Land Policy and Management Act
FWS	United States Fish and Wildlife Service
GCS	Geologic Carbon Sequestration
GS	Geologic Sequestration
IP/LP	Intermediate Pressure/Low Pressure
MEA	Monoethanolamine
NEPA	National Environmental Policy Act
NCA	National Conservation Area
NHPA	National Historic Preservation Act
NOI	Notice of Intent to Prepare an Environmental Impact Statement
PHMSA	Pipeline and Hazardous Materials Safety Administration
PSD	Prevention of Significant Deterioration
RCRA	Resource Conservation and Recovery Act
RMP	Resource Management Plan
ROD	Record of Decision
ROW	Right of Way
SDWA	Safe Drinking Water Act
SITLA	[Utah] School and Institutional Trust Lands Administration
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
USFS	United States Forest Service
VOC	Volatile Organic Compound
WFGD	Wet Flue Gas Desulphurization

1.0 INTRODUCTION

The Rocky Mountains of the western United States contain and produce over 50% of the coal in the country (U.S. Energy Information Administration, 2017). Because of this ready availability of coal in the region, coal-fired power plants continue to dominate electricity production. Despite recent uncertainty in federal regulations advocating "clean coal" and a boom in natural gas production, coal will likely continue to be the least expensive option for the near future due to existing plants and coal transport systems.

In order to address the CO_2 emissions from legacy coal-fired power plants, the U.S. Department of Energy solicited investigations of the long-term feasibility of an integrated CCS storage complex, with considerations toward commercial-scale CO_2 storage and/or utilization. The Rocky Mountain CarbonSAFE Phase I project was formed to address the conditions and attributes that would facilitate feasible and practical commercial-scale CCS. A site was chosen in central Utah that represents a typical scenario for the Rocky Mountains States, including a commercial CO_2 source in the form of a coal-fired power plant emitting approximately 9 MMT of CO_2 per year, and a commercial-scale CO_2 storage sink in the form of a 7,000 ft deep brine-bearing sedimentary rock formation that can accommodate over 50 MMT. The analyses contained within this document not only provides an evaluation of the feasibility of a CCS complex for Utah, but it also serves as the blueprint for additional CCS complexes elsewhere in the region, where coal power generating facilities and geology are similar.

1.1 OUTCOMES AND OBJECTIVES

The primary outcome of the Rocky Mountain CarbonSAFE Phase I project is a template protocol for existing and future coal-fired as well as natural-gas-fired plants in the Rocky Mountain states, with PacifiCorp's Hunter Plant in central Utah as the representative example of a typical generating station in the Rocky Mountain west. The template will benefit future CCS projects that utilize the vast, stacked deep-saline aquifers systems within the Rocky Mountain west that are capable of storing *billions* of metric tons of CO_2. The protocols developed by this project have addressed the technical and non-technical challenges specific to the Hunter power plant and the Buzzard Bench CO_2 storage complex near Castle Dale, Utah (Figure 1).

1.2 ROCKY MOUNTAIN CARBONSAFE TEAM

The Rocky Mountain CarbonSAFE Phase I formed a coordination team with extensive experience in the regulatory, legislative, geotechnical, stakeholder, commercial and financial challenges specific to CCS deployment. The team consisted of the geologists, geophysicists, engineers and law experts from the University of Utah, Utah Geological Survey, New Mexico Tech, Los Alamos National Laboratory and Sandia National Laboratory. The State of Utah Department of Environmental Quality took a lead role in interfacing with the U.S. EPA on their Class VI rules, as well as evaluating those rules as they apply to the project site. Schlumberger provided model development expertise. The Rocky Mountain CarbonSAFE Phase I industry partner was Rocky Mountain Power (an operational division of PacifiCorp, a Berkshire Hathaway Energy company), which operates several power plants in the region. The Hunter power plant, in central Utah, was proposed by Rocky Mountain Power as a test facility for CO_2 capture (part of a different U.S. Dept of Energy project) and the Primary Site option for this

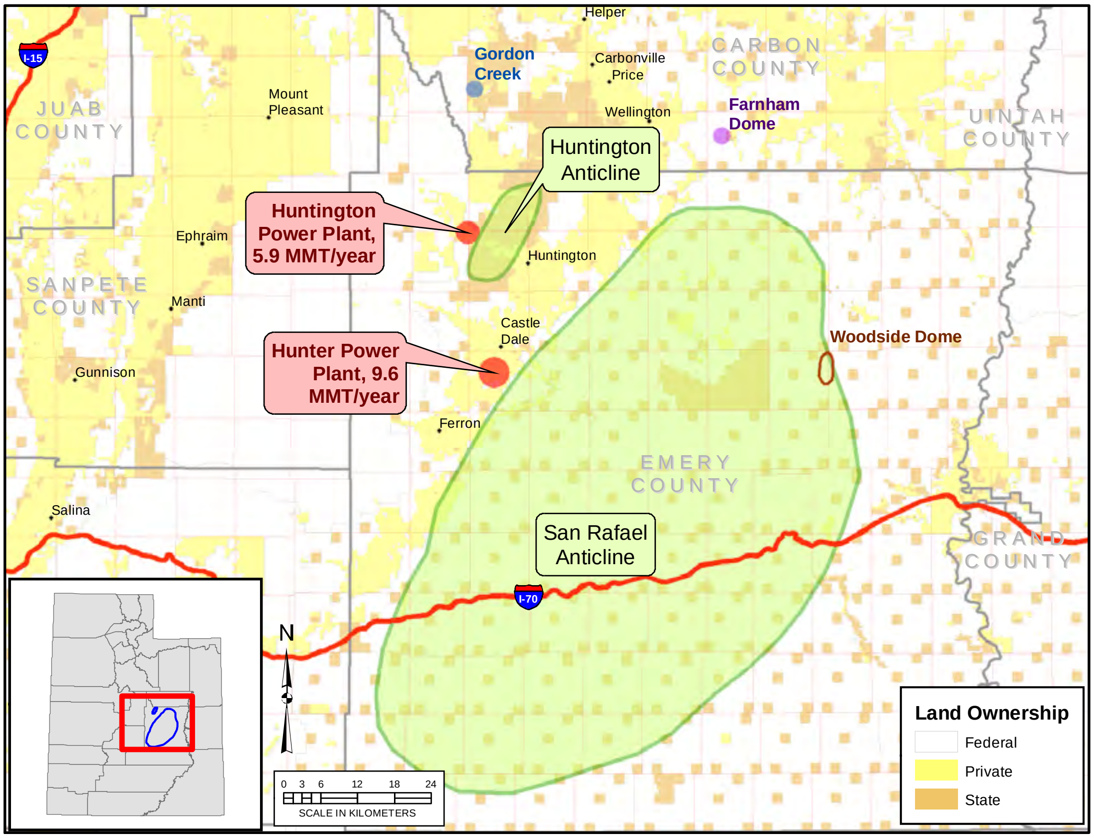

Figure 1. Map detailing locations of the primary and secondary CO2 sources and the assessed CO_2 storage complex comprised of the San Rafael Anticline and the adjacent Huntington Anticline.

proposal.

2.0 CO_2 Management

2.1 CO_2 SOURCE ASSESSMENT

2.1.1 Post Combustion CO_2

CO_2 in flue gas from a coal-fired power plant is targeted for capture in this study. The data from the Hunter power plant operated by Rocky Mountain Power is presented. Hourly flue gas rate, the compositions and net power generation are obtained from the data.

CO_2 in flue gas

The flue gas rate and compositions are varied hourly depending on the power requirement from the power plant. The mean CO_2 concentration (volume fraction) and mean flue gas rate are around 10.5% and 60 mmscf/hr respectively as shown in Figure 2 **(a)** and **(b)**.

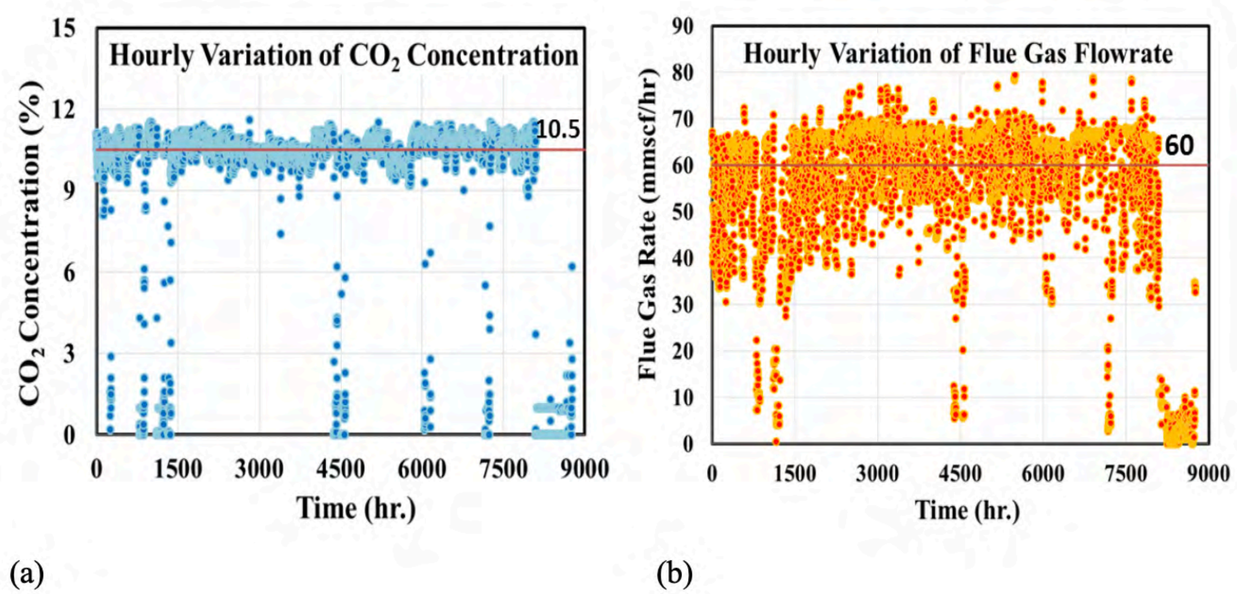

Figure 2. (a) Variation of CO2 concentration in flue gas (b) Variation of flue gas rate.

Emission Factor

The way to measure the environmental impact of power plant due to the emission of CO_2 with the flue gas is the determination of emission factor. This factor is defined as the amount of CO_2 (short ton) emitted to generate 1 MWhr of net power, as shown in Equation 1**.**

Equation 1.

$$Emission\ factor = \frac{CO_2 emission\ (short\ ton)}{Net\ Power\ Generated\ (\ MWhr)}$$

The emission factors calculated from the available data are plotted in Figure 3.

An approximate average 1.1 short ton of CO_2 is produced to generate 1 MW-hr power in coal fired power plant. Hunter power plant has a capacity of 1320 MW, thus providing a possible source of over 34,000 tons of CO_2 per day, and over 12 million tons per year. It is shown later that Hunter Unit 3 at various levels of capture is capable of providing 50 million tons of CO_2 over 30 years of operation.

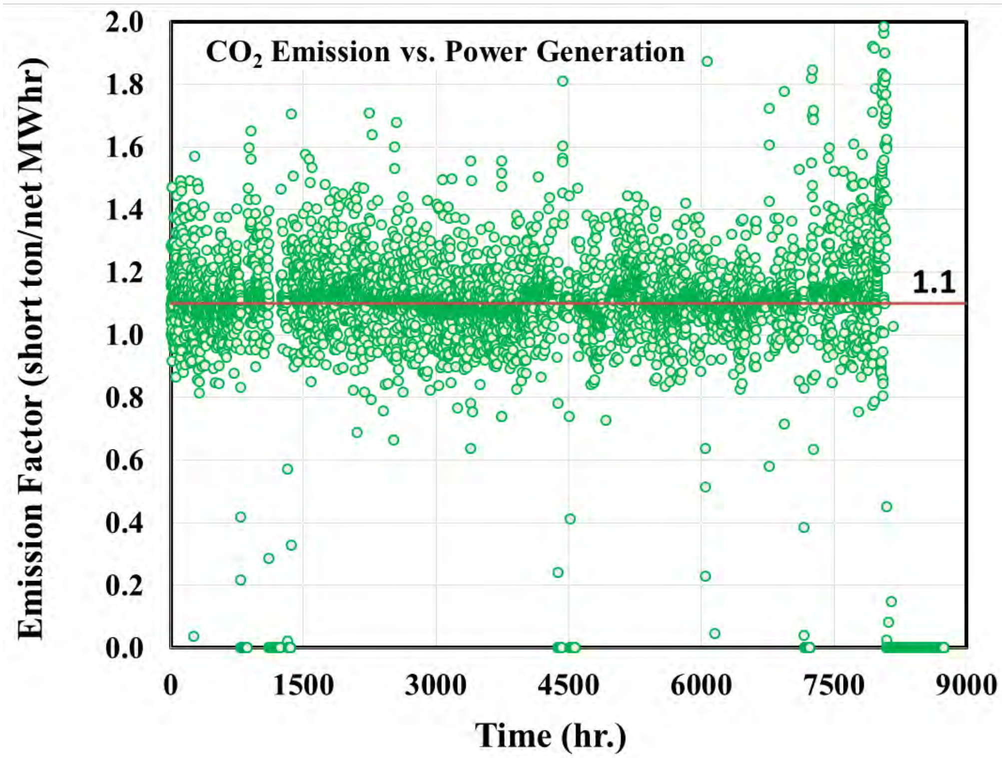

Figure 3. Emission factor for a unit of Pacific Corporation.

The Huntington power plant, as a secondary source has very similar emission characteristics, and with 895 MW capacity, provides well over 8 million tons of CO_2 per year as a source.

Monoethanolamine (MEA), a primary amine, is widely used as solvent for absorbing CO_2 in the method. Two main processing units namely absorber and regenerator are associated in the method. A typical process diagram for CO_2 capture and amine regeneration is shown in Figure 4**.**

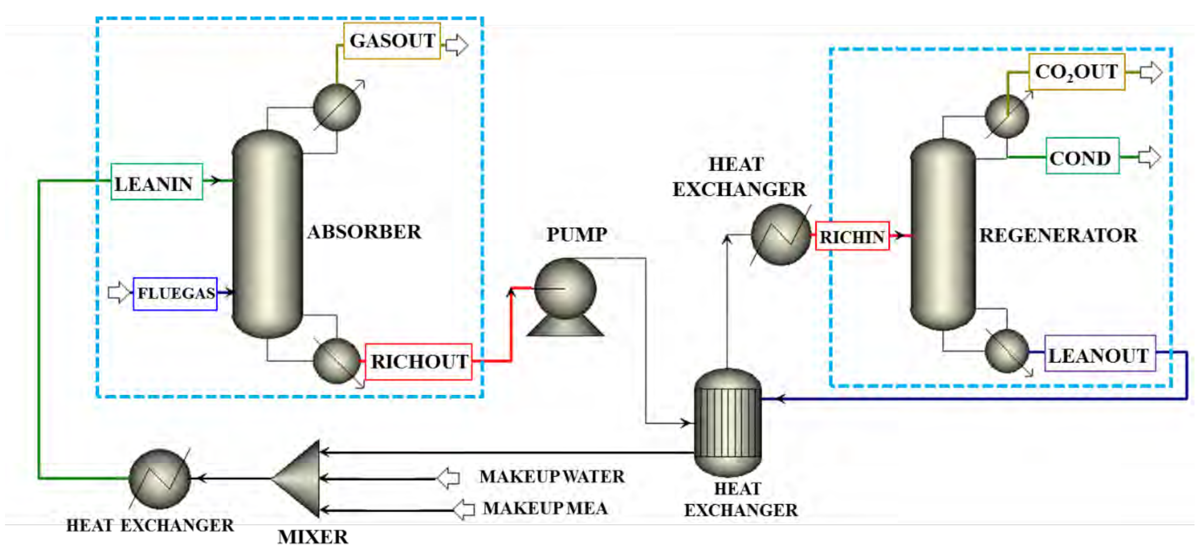

Figure 4. Integrated flow sheet of entire MEA process in ASPEN plus.

Absorber is used to capture CO_2 from flue gas and regenerator is used to separate the absorbed CO_2 from solvent i.e., to regenerate the MEA solvent. Lean aqueous MEA stream is recycled to absorber with fresh makeup MEA. As the part of the process plant, pumps, compressors, mixer, heat exchanger etc. are also connected. Simulations are run to evaluate the performance of the plant in removing CO_2 in flue gas from power plant.

CO_2 loading in lean MEA stream (α_L) is defined as shown in Equation 2.

Equation 2.

$$CO_2 loading\ in\ lean\ MEA\ stream, \alpha_L = \frac{mole\ of\ CO_2 in\ Lean\ MEA}{mole\ of\ MEA\ in\ lean\ MEA} = \frac{L\, x^L_{CO_2}}{L\, x^L_{MEA}} = \frac{x^L_{CO_2}}{x^L_{MEA}}$$

Where, L is the molar flowrate of lean MEA stream.

The cost of solvent for continuous makeup in the absorber is one of the major operating costs. Use of minimum flowrate of lean MEA stream to capture specified amount of CO_2 can reduce the operating cost. Using minimum lean MEA flow rate, more than 80% CO_2 is captured using absorber heights of 25 to 40 meters and CO_2 loading in lean MEA of 0.2 and less. Insignificant amounts of MEA (less than 0.2%) are lost for the entire range of absorber height (7m to 40 m) and CO_2 loading in lean MEA stream (0.1 to 0.35) according to results from this study. Operating cost due to handling MEA stream (pumping, cooling etc.) and make up MEA and water can be significantly reduced using minimum lean MEA flowrate with an optimized absorber height.

2.2 CO_2 CAPTURE ASSESSMENT FOR A COMMERCIAL CAPTURE PLANT

2.2.1 CO_2 Capture Assessment Using Established Technology

The University of Utah engaged Sargent & Lundy LLC (S&L) to evaluate the feasibility and overall cost of retrofitting Hunter Unit 3 with a state-of-the-art carbon capture system (see Appendix A for the full S&L report). Unit 3 was selected based on the amount of CO_2 in the flue gas, which was most practical for the goals of this project. This study effort included evaluation of multiple capture levels using a commercially available amine-based system as the basis for the capture technology. Three different levels of CO_2 capture possibilities on Hunter 3 were evaluated. The design basis was at least 50 million tons of CO_2 available over 30 years of project life for sequestration.

1. 65% capture, targeting no less than 1.84 million tons per year;
2. 90% capture, treating 100% of flue gas; and
3. Equivalent capture required (~48%) to achieve CO_2 emissions rate consistent with New Source Performance Standards (NSPS) for greenhouse gases for a natural gas-fired combined cycle plant (i.e. 1,000 lbs/MWh, gross)

This study effort includes evaluation of a commercially available amine-based system as the basis for the capture technology. S&L considered commercially available processes to be those that have been demonstrated during slipstream tests or have been implemented on permanent installations treating a quantity of flue gas that is at least equivalent to 5 MWe. Amine solvent-based technology has recently established itself as a viable technology for CO_2 capture. The commercial technology that was evaluated was Mitsubishi Heavy Industries (MHI) KM-CR Process® with KS-1™ solvent. As part of the techno-economic evaluation, the major balance of plant (BOP) impacts were identified and quantified, including loss of power generation due to both the auxiliary power load and the required process steam to be supplied from the base unit. Other BOP impacts are identified, including cooling and process water consumption, waste water generation rates, and solid waste generation rates. S&L also developed material balances and general arrangement drawings that reflect the integration of the CO_2 capture system with the base facility.

A full-scale capture system (Case 2: 90% capture) served as the basis for development of heat balances, mass balances, process flow diagrams, general arrangements, equipment sizing, and capital costs. The full-scale system inputs were adjusted for the two other capture facility design sizes: Case 1: 65% and Case 3: 1,000 lb CO2/MWhg.

Overall, the project is technically feasible for the PacifiCorp's Hunter Unit 3. Process steam will be provided by the base unit and extracted at the Intermediate Pressure (IP)/ Low Pressure (LP) crossover without disrupting the performance of the LP turbine; however, this will cause a unit derate by limiting the total amount of megawatts the turbines can produce. Other utilities provided by the base plant include process water makeup from the existing demineralized water system, cooling tower makeup water from the on-site storage basin and auxiliary power from the on-site storage basin, and auxiliary power from the existing auxiliary power transformer. Flue gas will be routed to the CO_2 capture island downstream of the Wet Flue Gas Desulfurization (WFGD) system, which reduces the amount of acid gas polishing that is required in the pre-scrubber. The CO_2 process is expected to generate pipeline quality liquid CO_2 for transportation to a storage field.

The costs of the projects for the three cases identified are summarized in Table 1.

Table 1. Cost of CO_2 Capture for the Hunter Power Plant Unit 3, using a commercially-available amine-based process.

Cost	Case 1 (65% Capture)	Case 2 (90% Capture)	Case 3 (1000 lb/MWh)
Total Cost, Millions of Dollars	518.14	666.22	421.94
Annualized Cost Millions of Dollars	64.4	82.11	52.45
Operation and Maintenance – Annual Cost in Millions of Dollars	66.27	85.84	52.7
Annual CO2 Captured in millions of tons	2.16	2.99	1.6
Cost of Capture per ton ($/ton)	61	50	74

2.2.2 Evaluation of Emerging Technology

This study included evaluation of feasibility and economics of an emerging CO_2 capture technology that is being developed by Sustainable Energy Solutions (SES). The SES Cryogenic Carbon Capture™ (CCC) system was identified by the University of Utah for evaluation in this study. The proposed technology differs from typical commercially available emerging CO_2 capture technologies inasmuch as it is not an amine-solvent-based process. Rather than circulating a solvent to absorb CO_2 from flue gas, the SES process uses a proprietary cryogenic process to chill flue gas and desublimate CO_2. S&L relied on SES to provide the process and cost information for the CO_2 island. S&L did not validate or verify the information provided. Based on the scope of supply from SES, S&L developed the balance of plant (BOP) design and overall costs for the project.

As part of the conceptual design, the major BOP impacts associated with the SES-specific CO_2 capture facility were identified and quantified by S&L. Other BOP impacts are identified, including cooling and process water consumption, waste water generation rates, and solid waste generation rates. S&L also developed material balances and general arrangement drawings that reflect the integration of the SES CO_2 capture system with the base facility. SES has yet to scale up their process to a commercial scale (> 5 MWe). Furthermore, prior to scaling up to the size of 100% treatment on Hunter Unit 3 would require additional intermediate stages for SES. Based on the limited details provided by SES and the infancy of the technology at this time, the project is not recommended for full scale CO_2 capture on PacifiCorp's Hunter Unit 3. However, a slipstream size island may be technically feasible with more process scale up from SES. At this time, there is not expected to be a fatal flaw based on the process design.

While no fatal flaw in the process design was identified, there may be some limiting factors due to permitting considerations. The factors that have the highest probability of becoming limiting factors moving forward are (1) the ability to dispose of hazardous pollutants in large quantity, (2) the ability to store hydrocarbons onsite, and (3) the potential for Prevention of Significant Deterioration (PSD) permitting to be triggered, based on criteria pollutant emissions increases. Volatile organic carbon (VOC) emissions are expected to increase after project execution, due to the hydrocarbon liquid coming in contact with the flue gas.

The total capital cost is based on the conceptual design of the CO_2 capture system defined in this study. SES provided capital cost information for the CO_2 capture process equipment for the Hunter application. S&L supplemented the CO_2 process equipment cost with a study-level BOP cost estimate based on S&L's experience within the utility industry, particularly experience on other CO_2 capture projects, projects at Hunter, and general Air Quality Control System (AQCS) projects.

Similarly, an estimate of the annual operation and maintenance (O&M) cost was developed based on the conceptual design defined in this study, using operating cost estimates from SES, supplemented by S&L's BOP O&M costs.

The results of this evaluation including the total capital cost, annual O&M cost, and cost of electricity (COE) are included in Table 2.

Table 2. Summary of cost of CO2 Capture using an emerging technology.

Cost	SES 95% Capture
Total Capital Cost in Millions of Dollars	507.22
Annualized Capital Cost in Millions of Dollars	63.05
Annual Operating Cost in Millions of Dollars	67.91
CO2 Captured in Millions of tons (Annual)	3.156
Cost of Capture ($/ton)	41.50

2.3 CO_2 TRANSPORT ASSESSMENT

Two CO_2 pipeline to transport the captured CO_2 to potential injection sites were designed. The pipeline routing is shown in Figure 5

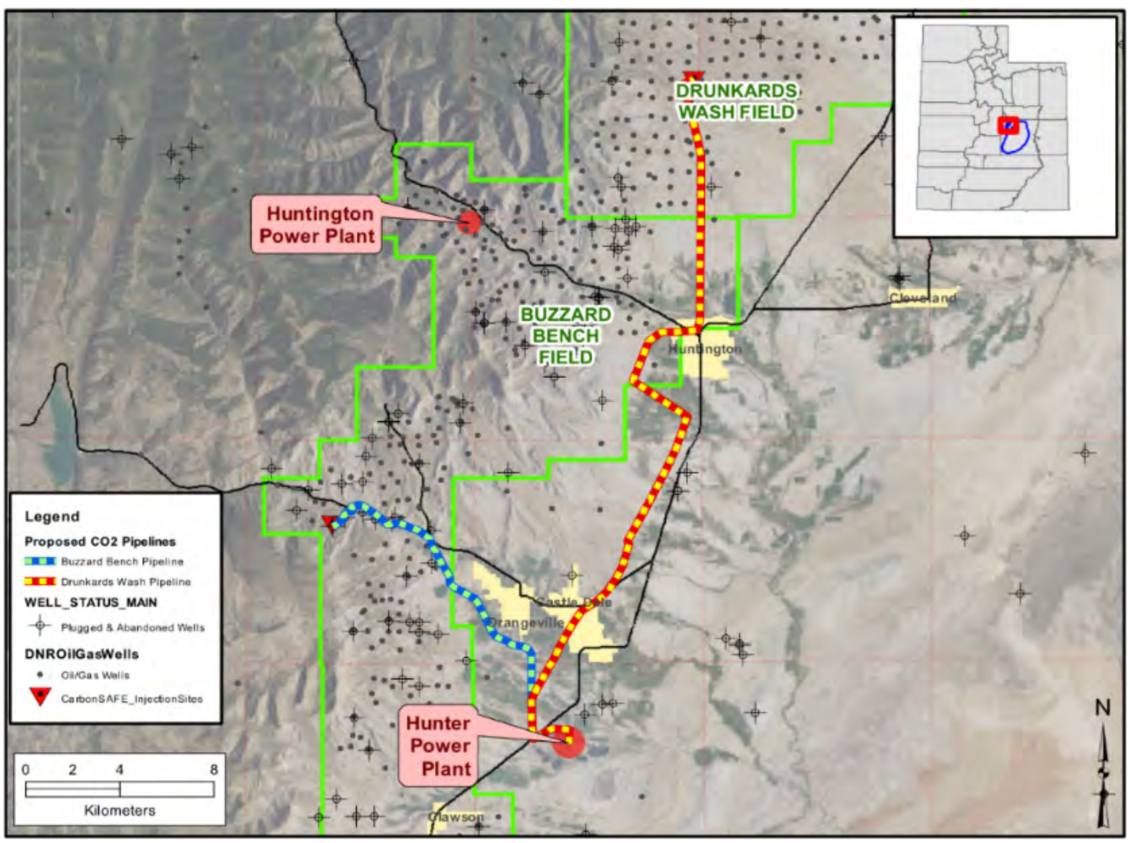

Figure 5. Aerial view of proposed injection sites and pipelines from Hunter power plant.

Detailed pressure drop calculations for the two pipelines were performed. Results are shown in Table 3.

Table 3. Results Summary for two proposed pipeline with 500 to 1500 psi pressure drop.

Parameters	Buzzards Bench	Drunkards Wash
Mass flow rate (ton/day)	5000	5000
Pipeline length (m)	18158	36593
Elevation gain (m)	218	293
Minimum p_1-p_2 (psi)	372	276
Mean velocity (m/s)	1.07-2.47	1.74-3.33
Pipeline diameter (inch)	7.2-10.9	6.2-8.6

2.4 INTERMEDIATE COMPRESSION

Intermediate compression or wellhead compression may be required depending on the elevation and length of pipeline. To determine the location of compression station, a pressure profile along the pipe line is calculated by the Equation 3.

Equation 3.

$$p = p_1 - \frac{8\,f\,Q_m^2\,x}{D^5 \rho\,\pi^2} + \rho g (Z_1 - z)$$

To illustrate the pressure profile along the pipelines, mass flow rate (Q_m) of 5000 ton/day and pressure drop (p_1-p_2) of 1000 psi are selected. Using calculated diameter (D=8.1 and 6.9 inches for Drunkards Wash and Buzzard Bench respectively) for the specified parameters, the pressure profiles of pipelines from Hunter power plant to Drunkards Wash and to Buzzard Bench are shown in Figure 6.

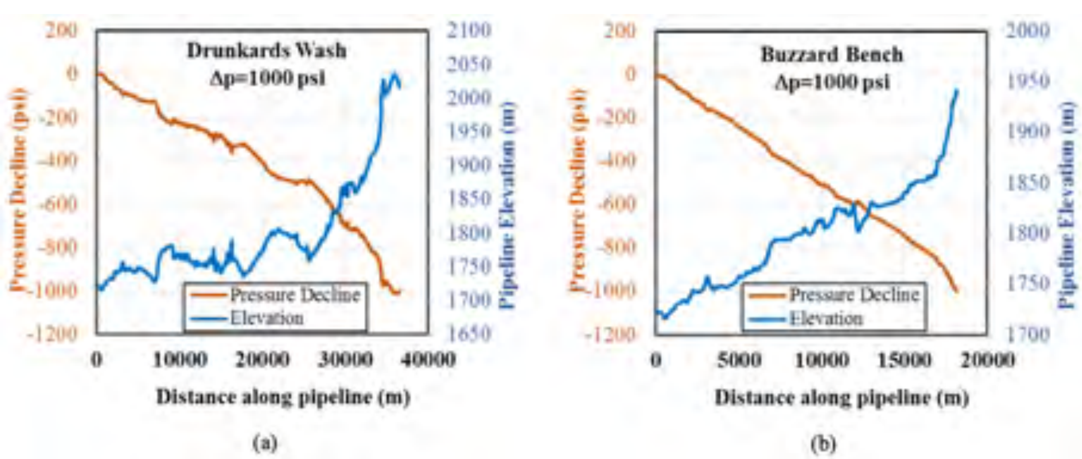

Figure 6. Pressure decline along the pipelines (a) Drunkard Wash Field and (b) Buzzard Bench Field.

3.0 Site Pre-Feasibility Plan

3.1 SITE CHARACTERIZATION

3.1.1 Overview of the San Rafael Swell

This project evaluated the potential for carbon capture and storage (CCS) of carbon dioxide (CO_2) from the Hunter and possibly Huntington coal-fired power plants in Castle Valley along the west flank of the San Rafael Swell in Emery County, Utah (Figure 7 and Figure 8). The San Rafael Swell is a broad, asymmetric, north-south- to southwest-northeast-trending anticlinal structure (Figure 8 and Figure 9), about 75 miles long and 35 miles wide in the Colorado Plateau physiographic province. The structure formed in response to compressional forces of the Laramide orogeny between late-Cretaceous time (about 70 million years ago [Ma]) and the Eocene (about 40 Ma) (Hintze and Kowallis, 2009).

The rocks in the San Rafael Swell have been folded, faulted, jointed, fractured, and uplifted. The major uplift and deformation of the San Rafael Swell was likely controlled by a large, blind, basement-involved reverse fault (up on the west side) bounding the east flank of the structure (Figure 9). Small to large subsidiary anticlines (e.g., Farnham Dome on the north-plunging nose) and synclines occur north to south along the uplift. Three sets of high-angle normal faults are mapped on the surface: (1) northwest-southeast striking, (2) east-west striking, and (3) north-south to northeast-southwest striking (Chidsey, 2013). Two styles of reverse faulting are identified in the San Rafael Swell: (1) west-directed, blind reverse faults on the east flank, and (2) east-directed, ramp-style thrusting. Sandstone beds are quartz rich and brittle, and when folded or bent produce prominent joints and fractures.

The subsurface sedimentary section consists of Cambrian, Devonian, Mississippian, and Pennsylvanian strata overlying Precambrian crystalline basement rocks consisting of schist and granite dated at 1800 Ma (Hintze and Kowallis, 2009). The surface sedimentary section consists of Permian through Cretaceous strata (Figure 10) (note: a small location in Eardley Canyon exposes Mississippian Redwall Limestone). These rocks were deposited in a wide range of environments including eolian, floodplain, fluvial, braided stream, deltaic, paludal, tidal flat, and shallow and restricted marine. Several major unconformities represent significant periods of erosion or non-deposition.

Gray marine shale beds of the Upper Cretaceous Mancos Shale form the strike valleys that surround the San Rafael Swell and upon which most highways and towns are located, as well as the Hunter Power Plant (Figure 7 and Figure 9). The deltaic sandstone and coal beds of the Upper Cretaceous Mesaverde Group make up the Book Cliffs to the north and east, and Wasatch Plateau to the west of the San Rafael Swell where the Huntington Power Plant is located (Figure 7).

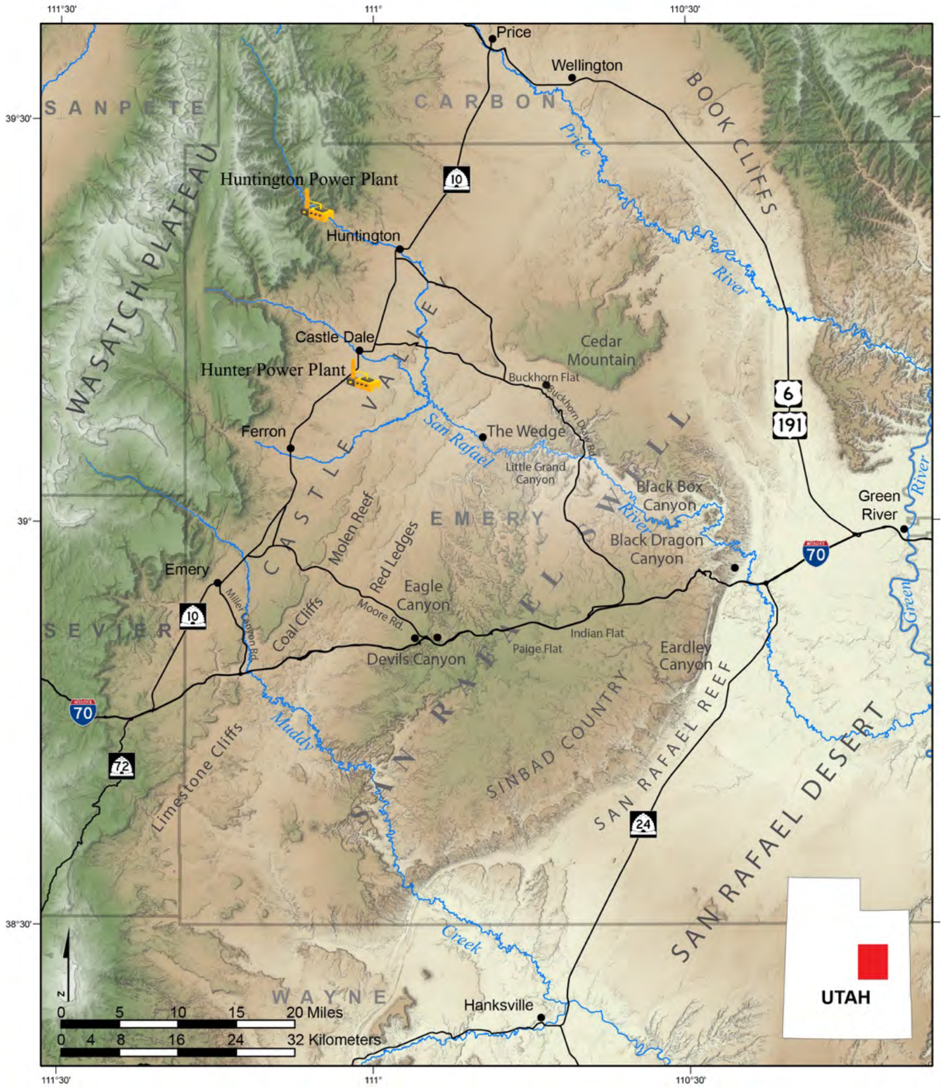

Figure 7. Physiographic map of the San Rafael Swell, east-central Utah, showing the location of major physiographic features, surrounding towns, highways, and the Hunter and Huntington power plants.

Site Characterization Subtasks

Ideally, reservoir and seal characterization should offer insight into both large-scale stratigraphic trends via outcrop-study, as well as petrophysical and geochemical characterization of the subsurface via core descriptions and/or well analysis, where data are available. The goal of subtask 3.1, Site Characterization, was to provide the geologic, geophysical, and hydrologic properties of reservoir formations (Permian White Rim and Jurassic Navajo Sandstones as primary targets; Mississippian Redwall Limestone as a secondary target) and all overlying seal formations (Permian Kaibab, Triassic Moenkopi, and Jurassic Carmel Formations) for both Primary (Hunter) and Secondary (Drunkards Wash) sites (Figure 8 and Figure 10). This work included (1) mapping and determining the extent and integrity of storage and sealing formations, (2) mapping and describing known faults and fractures, (3) evaluating both outcrops and available cores (porosity, permeability, and petrography), (4) analyzing the water chemistry from area wells, (5) determining the hydrological properties of the reservoirs, and (6) describing the potential for seismic activity. This site characterization provided the geologic model for the development of a reservoir simulation model that was utilized to assess the storage potential and behavior. A geologic model of the site options was the outcome of this subtask.

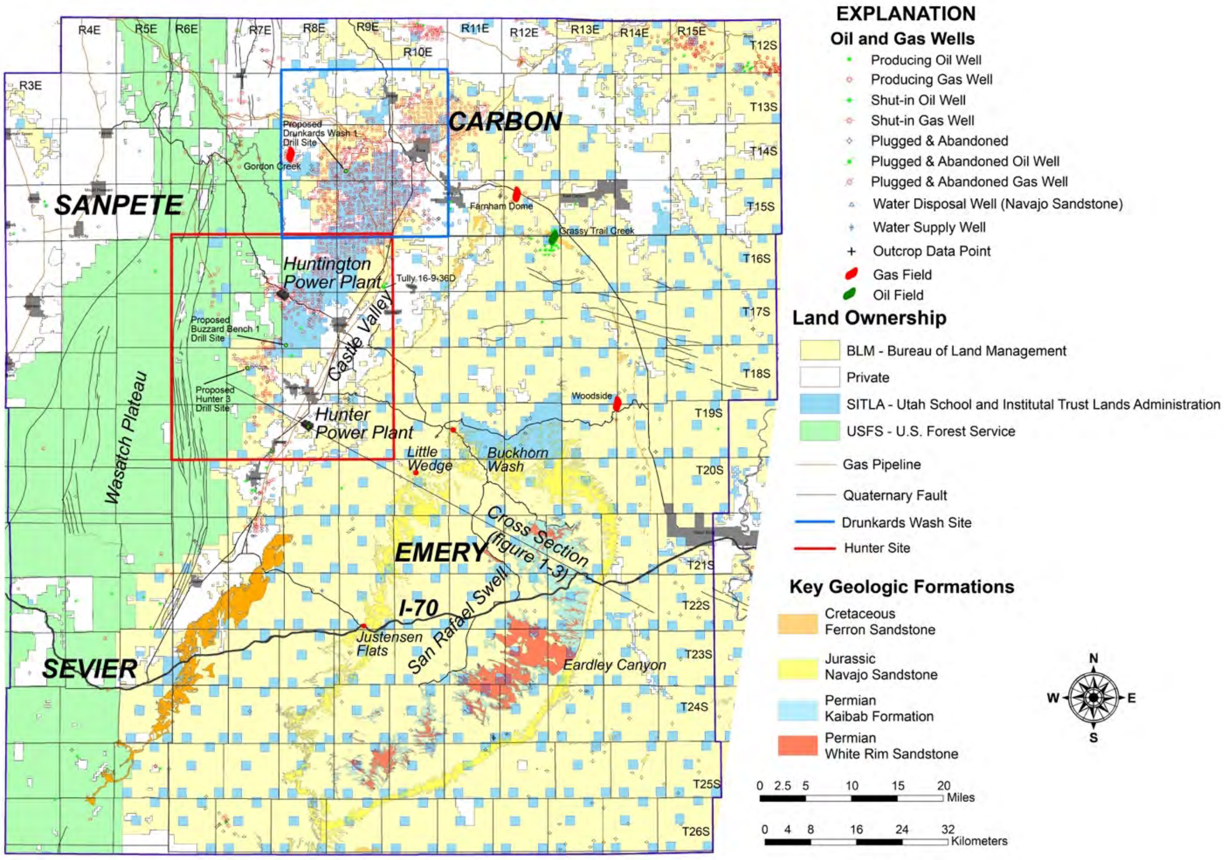

Figure 8. Regional index map of the study area, Carbon, Emery, and parts of Sanpete and Sevier Counties, Utah. Hunter site (red outline) and Drunkards Wash site (blue outline). The proposed Buzzard Bench No. 1 in the Hunter site is the primary injection location and the proposed Drunkards Wash No. 1 (DW1) location is the secondary. Cross section shown on Figure 9.

Discussion: Selection of the Reservoir for Carbon Dioxide Storage

Permian White Rim Sandstone

Originally, the eolian Permian White Rim Sandstone (Figure 10) was considered a likely potential storage reservoir for the project. The CO_2 storage potential of the White Rim Sandstone was investigated by Harston and others (2013) where it is exposed on the east flank of the San Rafael Swell and in the subsurface at Woodside field on a subsidiary anticline along the east flank of the Swell. Porosity measurements from outcrop samples have a range of 7.6% to 24.1% and permeability up to 2.1 millidarcies (mD). The eolian facies has the best reservoir quality and is volumetrically the most significant in comparison to the marine part of the White Rim (Harston and others, 2013). However, storage capacity at Woodside field is limited by the structural closure and was calculated at 2.2, 8.8, and 23.7 million metric tonnes for P10, P50, and P90, respectively (Harston and others, 2013).

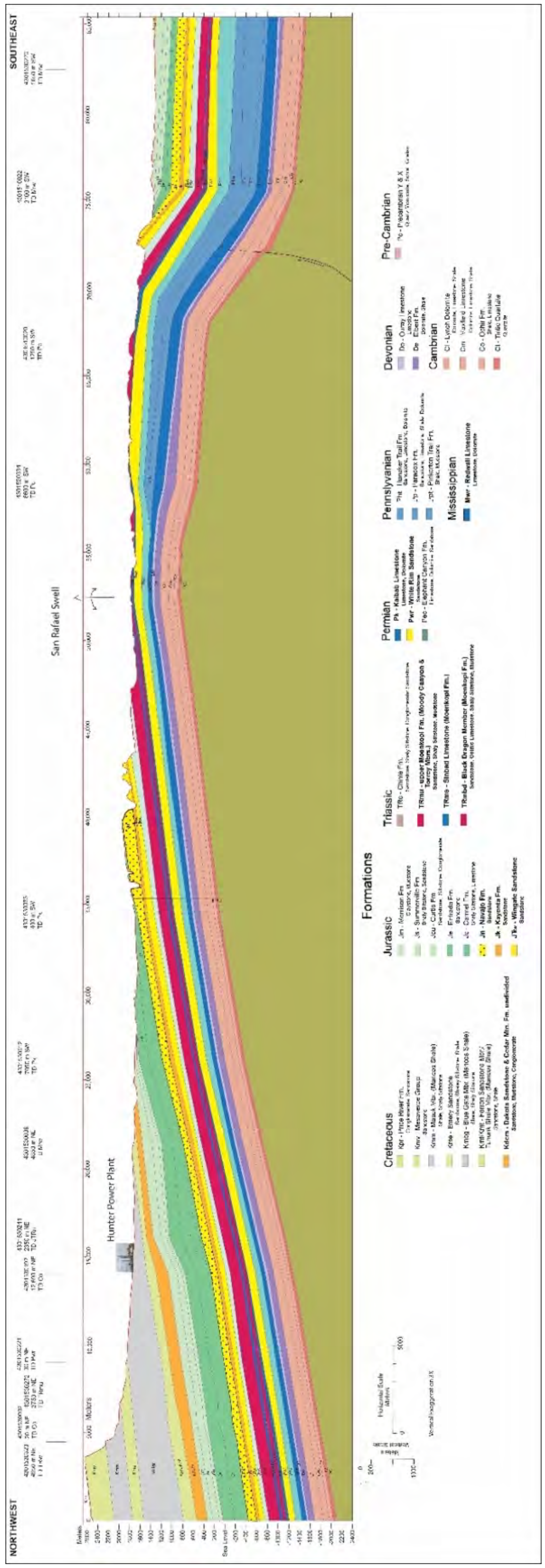

Figure 9. Northwest to southeast geologic cross section of the San Rafael Swell through the Hunter Power Plant location. Navajo Sandstone, targeted for CO_2 injection, shown with dotted pattern. See Figure 8 for location of cross section.

High flow rates of CO_2 were tested from the White Rim Sandstone at Gordon Creek field in the Wasatch Plateau within the Drunkards Wash area southwest of Price (Figure 8). A drill-stem test of the White Rim in the Gordon Creek No. 1 well (SENE section 24, T. 14 S., R. 7 E., Salt Lake Base Line & Meridian (SLBL&M), Carbon County) gauged a flow of 8.8 million cubic feet of gas per day (MMCFGPD). The well was completed as a CO_2 well but never produced. Three other wells drilled and tested CO_2 at Gordon Creek, confirming a large resource. Geophysical well logs show porosity of 2% to 4% suggesting fractures play a significant role in the White Rim reservoir at Gordon Creek (Morgan and others, 2013). The White Rim was also going to be a source for CO_2 in the Gordon Creek saline aquifer demonstration which was canceled when the Environmental Protection Agency (EPA) made the Class VI requirement for the demonstration wells (Morgan and others, 2013).

Finally, Whiting Petroleum Company cored most of the Triassic Moenkopi Formation, all of the Permian Kaibab Formation, and the upper White Rim Sandstone (50 feet) in the Tully No. 16-9-36D (NWNW section 36, T. 16 S., R. 9 E., SLBL&M, Emery County). The White Rim reservoir quality in the core, particularly permeability, was poor. The core also had very low porosity (mostly 1% to 2%) which matches density-neutron-log porosity values throughout the entire White Rim when correlated to porosity logs from other wells in the area. The White Rim is deeper in Castle Valley than Woodside Dome, and at that greater depth, the diageneses of the sandstone that created porosity at Woodside has not occurred at Castle Valley.

These factors led to the conclusion that the White Rim Sandstone most likely does not have the reservoir quality necessary to be considered for CO_2 injection and storage in Castle Valley. As a result, a second potential target was identified and studied.

Jurassic Navajo Sandstone

Our attention shifted to the eolian Lower Jurassic Navajo Sandstone as a top candidate for CO_2 injection. The Navajo Sandstone is relatively undeformed, widespread, and thick. It has excellent reservoir and aquifer properties producing oil in the central Utah thrust belt, CO_2 in the San Rafael Swell, and serves as a water disposal unit. The Navajo reservoir is sealed by overlying marine units of the Middle Jurassic Carmel Formation.

Farnham Dome field, located on the north-plunging nose of the San Rafael Swell (Figure 8), produces naturally occurring CO_2 from the Navajo Sandstone. The trap for the field is a broad, elongate, south-north- to southwest-northeast-trending anticline defined by surface mapping, drilling, and seismic data (Morgan, 2007). The CO_2 was likely generated from the thermal decomposition of Paleozoic carbonates deep in the Uinta Basin to the north and migrated up the stratigraphic section to Farnham Dome (Morgan, 2007). The net Navajo reservoir thickness is 40 feet over a 6200-acre area; the gas column is about 400 feet (Morgan, 2007). Despite the massive nature of the Navajo Sandstone, interdune deposits and other factors contribute to reservoir heterogeneity. Porosity ranges from 18% to 20%; permeability is poorly-constrained. Cumulative production as of May 1, 2018, is estimated at 6.4 BCFG and no water (Utah Division of Oil, Gas and Mining, production records). Total gas-in-place reserves are estimated at 430 BCFG at Farnham Dome (Morgan, 2007).

The Navajo Sandstone has also been used for disposal of produced water from the many coalbed methane wells in the area producing from the Cretaceous Ferron Sandstone (Figure 10), demonstrating the formation's high-injectivity potential and effective overlying seal. There are no cores of the Navajo in Castle Valley and therefore permeability is based on outcrop studies (Dalrymple and Morris, 2007) and porosity and permeability from core taken in the Covenant field about 65 miles southwest of Hunter (Chidsey and others, 2007). Porosity is better in the Castle Valley area, as such the permeability in Castle Valley is likely better than the Covenant field as well.

The Farnham Dome field has served as a model for geologic carbon capture, utilization, and storage of flue gases from coal-fired power plants on the Colorado Plateau (Allis and others, 2001). Findings from this study and our initial well log correlations, subsurface mapping, and characterization studies of the Navajo Sandstone reservoir and the Carmel Formation seal concluded that the Navajo was the best reservoir in the region for CO_2 storage. Note: a major concern with the Navajo is the close proximity of the outcrop to the Hunter Power Plant (Figure 8). As a result, an injection location west and down dip from the plant was selected—the proposed Buzzard Bench No. 1 well (NENE section 31, T. 17 S., R. 8 E., SLBL&M) within the Hunter study site (figure 1-2). A secondary injection location within the Hunter study site is the Hunter No. 3 well (NWNW section 16, T. 17 S., R 7 E., SLBL&M). Finally, the proposed injection location for the Drunkards Wash study site is the Drunkard Wash No. 1 well (SESE section 30, T. 14 S., R 9 E., SLBL&M) (Figure 8).

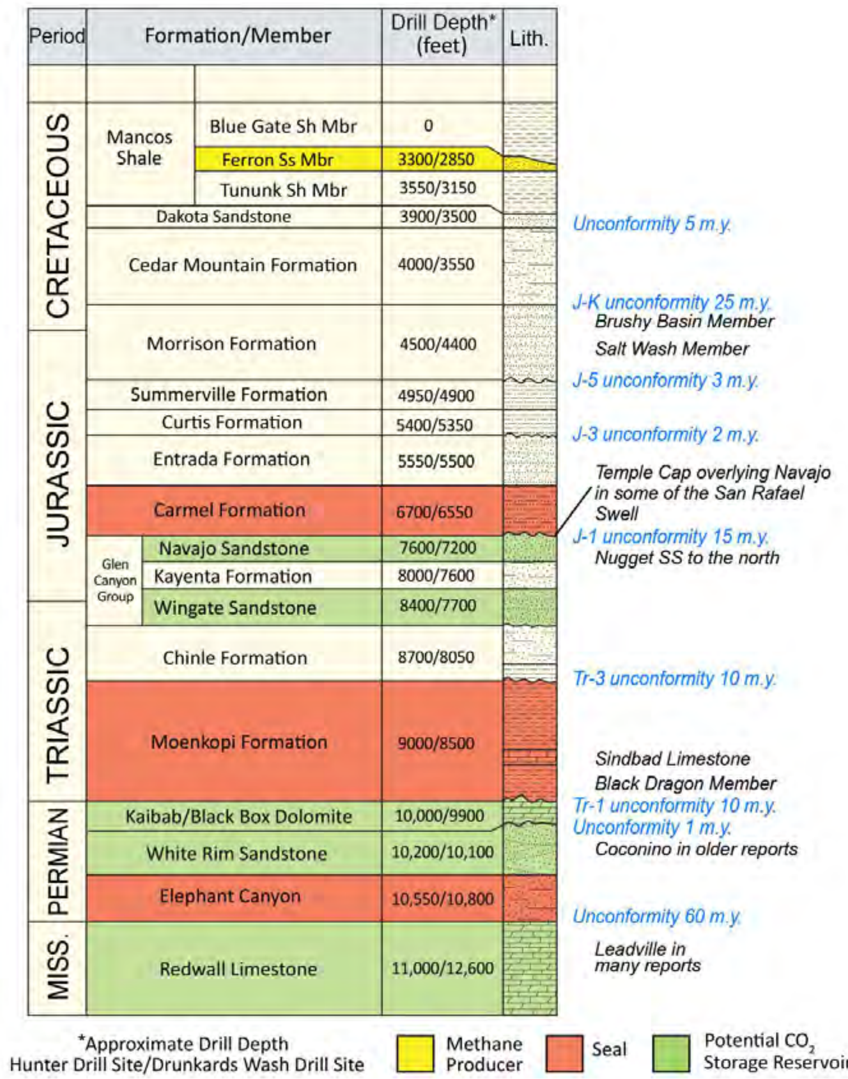

Figure 10. Stratigraphic column for the Castle Valley area, Emery County, Utah. Drill depths are for the proposed drill sites Hunter No. 3 (NWNW section 16, T. 18 S., R. 7 E., Salt Lake Base Line & Meridian [SLBL&M]) and Drunkards Wash No. 1 (SESE section 30, T. 14 S., R. 9 E., SLBL&M). Modified from Hintze and Kowallis, 2009.

3.2 MODEL DESIGN AND SIMULATION

During this project, we built three different simulation models to address different aspects of the storage site pre-feasibility study. An initial 2D scoping model was developed to determine if CO_2 storage at this site was possible due to the 'unconfined' nature of the potential reservoir. A second model was then developed to address the storage of 50 million tons of CO_2 at a primary storage site, Buzzards Bench, and a secondary storage site, Drunkards Wash. And finally, we developed a third model that encompassed both the Buzzards Bench and Drunkards Wash storage sites into one domain. The primary goal of the simulation part of the study was to determine if the permanent storage of 50 million tons of CO_2 is feasible in this area of central Utah. A second goal was to explore the total possible capacity in the area if it was used as a regional geologic carbon storage site. A detailed discussion of these three models is described below.

3.2.1 2D Vertical Scoping Model

A 2D vertical reservoir model was created as an initial scoping tool to determine the magnitude of plume movement up-dip from two possible injection sites, one directly under the Hunter Power Plant and one about 6 miles west of the power plant. The model is from the Colorado Plateau on the west to the crest of the San Rafael Swell to the east, A to A' in Figure 11. The San Rafael Swell is an anticline, with the formations dipping to the west at about 3.5% (Figure 12).

Only the major formations of interest were model while the overlying and underlying formations were combined to reduce computational overhead and unnecessary complexity. Two injection zones were initially evaluated, the Glen Canyon Formation, consisting of the Navajo Sandstone, the Kayenta Formation, and the Wingate Sandstone, and the White Rim Sandstone. The sealing formation for the Glen Canyon Formation is the Carmel, which is a laterally continuous formation overlying the Navajo Sandstone in this area. The Moenkopi Formation and Black Box Dolomite are sealing units overlying the White Rim Sandstone. The Carmel and Glen Canyon Formation all outcrop about 11 miles (18 km) east of the Hunter Power Plant site, while the White Rim Sandstone only outcrops in a few isolated areas of the Swell even further east.

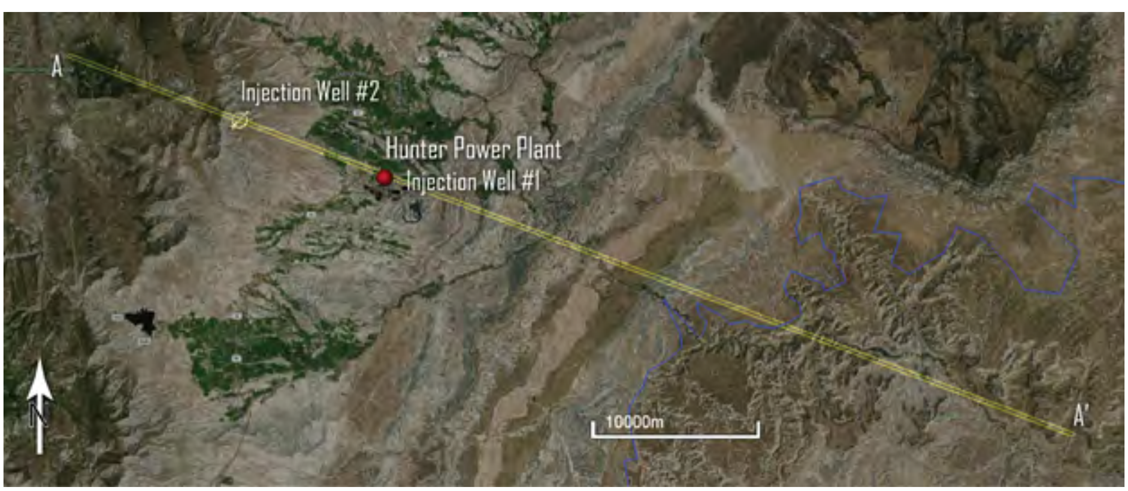

Figure 11. Overview of the area that encompasses the 2D vertical model. The model domain follows the slice from A to A'. The purple line represents where the Navajo Sandstone outcrops in the area.

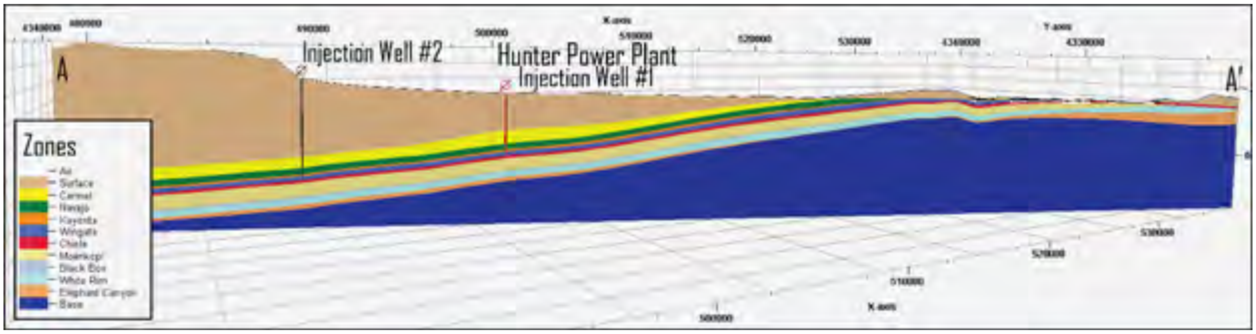

Figure 12. A plot of the model domain showing the relevant stratigraphy under Hunter Power plant. There is a 5x vertical exaggeration in the plot.

CO_2 Injection – Potential Location

Two potential CO_2 injection well locations were specified and analyzed, one directly under the Hunter Power plant (Injection Well #1) and a second injection well 5.8 miles (9.3 km) northwest or down-dip from the power plant site (Injection Well #2). The injection well #1 is the ideal location for the injection well, directly under the power plant. But, this well, at 4215 feet (1285 m) deep, may be too shallow and too close to the outcrops to effectively contain the CO_2 plume in the Glen Canyon Formation over the long term. The White Rim Sandstone is much deeper under the power plant, 6587 feet (2008 m), making it a better storage target than the shallower Glen Canyon Formation. The second injection well, Injection Well #2, was located further east, down-dip, of the power plant. Here the top of the Glen Canyon Formation is at a much greater depth, 7103 feet (2165 m). The White Rim Sandstone is 10,040 feet (3060 m) deep at this injection site.

Carbon dioxide is injected for 30 years with a bottom hole pressure limit of 5800 psi (400 bar). The injection wells are set for bottom hole pressure control so they will inject CO_2 at the maximum rate the reservoir will allow while keeping the bottom-hole pressure below 5800 psi. The simulation was run for a total of 500 years, from 2017 to 2517.

Reservoir Properties

Very little was known about the fluid and rock properties of this potential storage site. For this model, some assumptions and simplification were used in lieu of formation and site-specific data. Those will be discussed in detail below.

Permeability and Porosity

When this model was constructed there was very little petrophysical data in the study area for the formations of interest. The majority of petrophysical data is for the much shallower, natural gas producing Ferron Sandstone. Due to this, permeability and porosity values were estimated from very generic data presented by Hood and Patterson (1984) and assigned homogeneously across the reservoir domain. Table 4 has the permeability and porosity values used in this model.

Table 4. Permeability and porosity values assigned homogeneously across each formation.

Formation	Porosity	Permeability (mD)
Overburden	10%	0.1
Carmel	2%	0.1
Navajo	20%	200
Kayenta	20%	100
Wingate	20%	200
Chinle	2%	0.1
Moenkopi	2%	0.1
Black Box	10%	0.1
White Rim	7%	1
Elephant Canyon	2%	0.1
Basement Granite	2%	0.1

Relative Permeability and Capillary Pressure

Characterization of fluid/rock interaction for the formations of interest, such as relative permeability and capillary pressure, was also lacking. Three different relative permeability relationships were specified that covered the possible parameter space. We chose the default relative permeability relationship for 'sandstone' in Petrel©, the van Genuchten formula, and the Corey's Curve formula (Pruess et al., 1999). Figure 14 shows the three curves with the default as the solid lines, the van Genuchten curve as the dashed lines, and the Corey's Curve as the dotted lines.

The capillary pressure was ignored in the default case. The capillary pressure was calculated using Leverett's formula for the other two cases (Pruess et al., 1999).

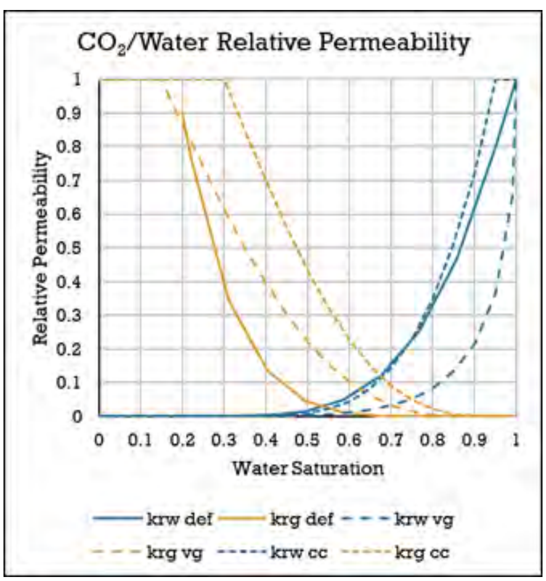

Figure 13. Three relative permeability curves used in the scoping model. 'k_{rw}' is the relative permeability to water and 'k_{rg}' is the relative permeability to gas. The solid lines represent the default relative permeability curve in Petrel, the dashed line is the relative permeability calculated with the van Genuchten formula, and the dotted curve is the relative permeability calculated with the Corey's Curve formula.

Fluid Model & Boundary Conditions

The two-phase CO_2 and water system was modeled by using the CO2STORE keyword in the Eclipse© simulator. This keyword models CO_2/Brine interactions more accurately than the default three-phase equation of state. Initially, there is only brine present in the reservoir with a temperature of 131 °F (55 °C). The pressure is hydrostatic and initialized through equilibrations with a datum depth of mean sea level and a reservoir pressure at the datum depth of 2755 psi (190 bar). Dirichlet boundary condition was specified for the surface layer and set to 14.7 psi (1 atm) and assigned a 'large volume' (10^7 m^3). The lateral and bottom boundaries were set to no flow. The lateral boundaries are far enough away from both injection wells such that injection pressures are not influenced by the boundary conditions.

Results

As was initially suspected, CO_2 injected directly under the Hunter Power Plant (Injection Well #1) into the Glen Canyon Formation migrated up-dip until it reached a depth of about 800 meters where the CO_2 changed phase from supercritical CO_2 to gaseous CO_2. This phase change happened at about 135 years into the simulation and indicated a loss of CO_2 containment.

The White Rim Sandstone proved to be a poor candidate for CO_2 storage as it is hampered by poor injectivity resulting from low permeability. Further simulations were not carried out using the White Rim Sandstone as a reservoir.

Table 5. Total gas (CO_2) in each model permutations at the end of injection, the end of the monitoring period: (Post-Injection Site Care; PISC), and the end of the simulation. Units are in short tons.

Total CO_2 In Place (tons)			
Model	End of Injection		
	Free Gas	Trapped Gas	Dissolved Gas
Default RP	5,606,750	677,131	607,784
Corey's Curve RP	6,391,868	536,575	439,170
van Genucten RP	5,788,011	1,076,159	417,360
	End of PISC		
	Free Gas	Trapped Gas	Dissolved Gas
Default RP	5,250,764	796,976	843,917
Corey's Curve RP	6,352,068	533,600	481,958
van Genucten RP	5,754,908	1,069,190	457,427
	End of Simulation		
	Free Gas	Trapped Gas	Dissolved Gas
Default RP	5,606,750	1,106,769	1,664,986
Corey's Curve RP	6,391,868	539,067	505,188
van Genucten RP	5,788,536	1,079,243	475,107

Moving CO_2 injection to Injection Well #2, located about 6 miles to the west of Hunter, showed mixed results. Achieving containment at this injection site depends on the specified relative permeability and capillary pressure relationship. Using the default relative permeability relationship without capillary pressure, injected CO_2 migrates about 16km (~10 miles) up-dip by the end of the simulation. A distance far past the Hunter site and close to where the reservoir outcrops, indicating a loss of containment (Figure 14a). Changing the relative permeability relationship and adding capillary pressure slows the plume movement and keeps it more localized, moving between 4 and 6 miles over 500 years (Figure 14b and Figure 14c). Results show that ignoring the capillary pressure has a significant impact on the distance the CO_2 plume can migrate. One consideration for this site is ignoring capillary pressure may be unrealistic as CO_2 and brine are not miscible at the conditions found under the Colorado Plateau. At the pressure and temperature regime at the site, there will be a distinct capillary pressure relationship.

The maximum amount of CO_2 that can be injected is affected by the relative permeability and capillary pressure relationship specified. Table 5 shows that changing the relative permeability curves imparted about a 6% variation in total CO_2 injected into the model.

Overall this scoping model has indicated that this area of the Colorado Plateau and nearby San Rafael Swell is a possible candidate for long-term storage of anthropogenic CO_2. These results warrant further investigation and construction of a more detailed geologic model.

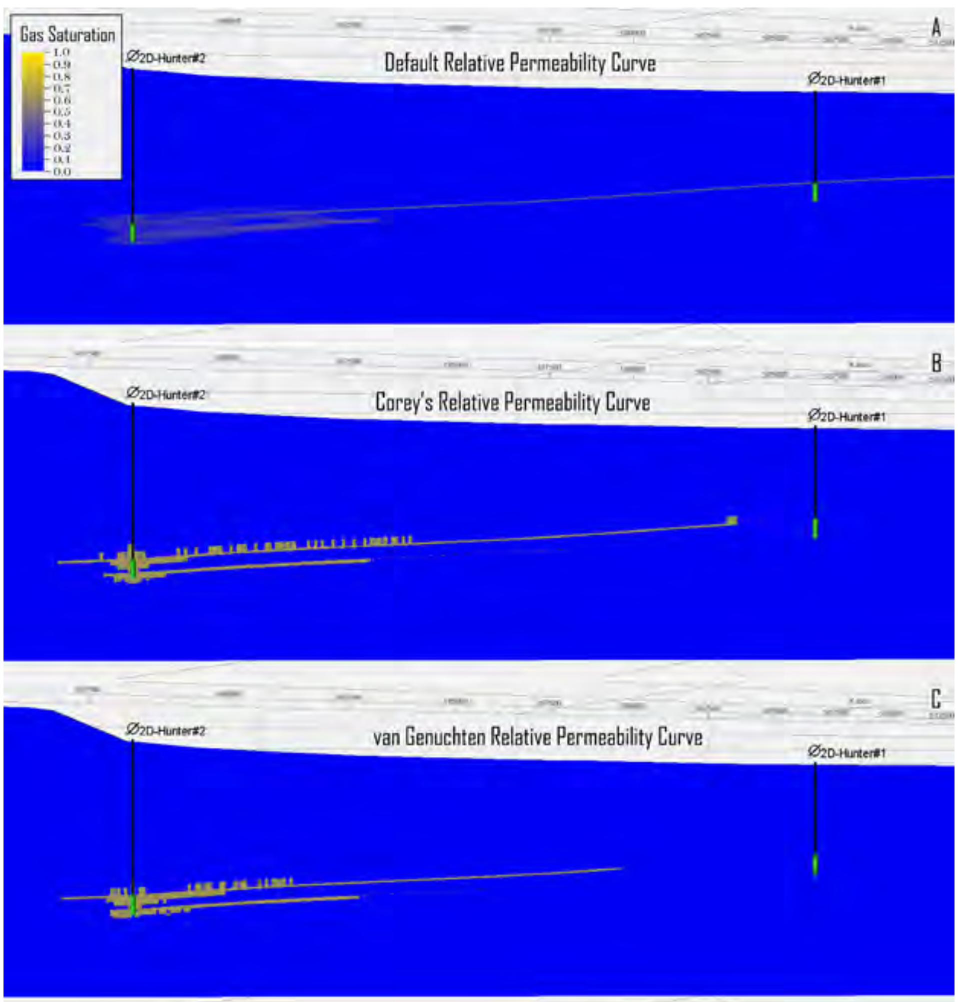

Figure 14. Predicted CO_2 saturation at the end of the simulation (500 years) using the Petrel default curve for sandstone (a), Corey's curve (b) and the van Genuchten curve (c).

3.2.2 NRAP Well-Bore Leakage Models

The EPA class VI guidance documents specify that if a reservoir is in a hydrostatic to over-pressurized state than the Area of Review (AOR) assessment need to be delineated using numerical modeling. We determined that the Navajo Sandstone in our study area is likely at hydrostatic to slightly over pressurized state. To address this requirement a geologic model was constructed, and two model domains were delineated by the Schlumberger team (Si-Yong Lee). One model domain encompassed our primary injection site about 8.5 miles northwest of the Hunter Power Plant in an area called Buzzards Bench. The second model domain encompasses our secondary injection that is 28 miles north of Hunter in an area of called Drunkards Wash. Figure 15 shows these two domains in relation to Price and Castle Dale, Utah.

Simulation Domains and Initial Model Conditions

The model encompassing our primary injection site is referred to as the Buzzards Bench model and the model encompassing our secondary injection site as the Drunkards Wash model. Figure 16 shows an overview of the study area with a yellow square for the Buzzards Bench model domain and a red square for the Drunkards Wash model domain along with the location of each of the two proposed injection wells.

The Buzzards Bench model domain is discretized into 200,000 cells, 100(x) by 100(y) by 20(z). The Drunkards Wash model domain is discretized into 273,798 cells, 123(x) by 106(y) by 21(z). The simulation domain models only the Carmel Formation that forms the sealing unit overlying our principal reservoir, the Glen Canyon Formation (Navajo, Kayenta, Wingate formations) and the underlying sealing unit of the Chinle Formation. The overlying layers were omitted to reduce model complexity and computation overhead. The thickness and low permeability of the Carmel Formation should not allow any vertical fluid migration. The lateral boundaries were set to a large volume to maintain a constant pressure, and the top and bottom boundaries were set to no flow. The initial pressure distribution was set to hydrostatic conditions, consistent with the available data (Hood and Patterson, 1984).

The porosity and permeability were derived from initial characterization data take in the field and from well logs and well reports. To keep the simulation design simple, it is assumed that the porosity and permeability are correlated and have a homogeneous distribution. We believe that the homogeneous distribution is adequate for our purpose because the cell size (200 x 200 meters) is much larger than the correlation length seen in the field, on the order of only tens of meters.

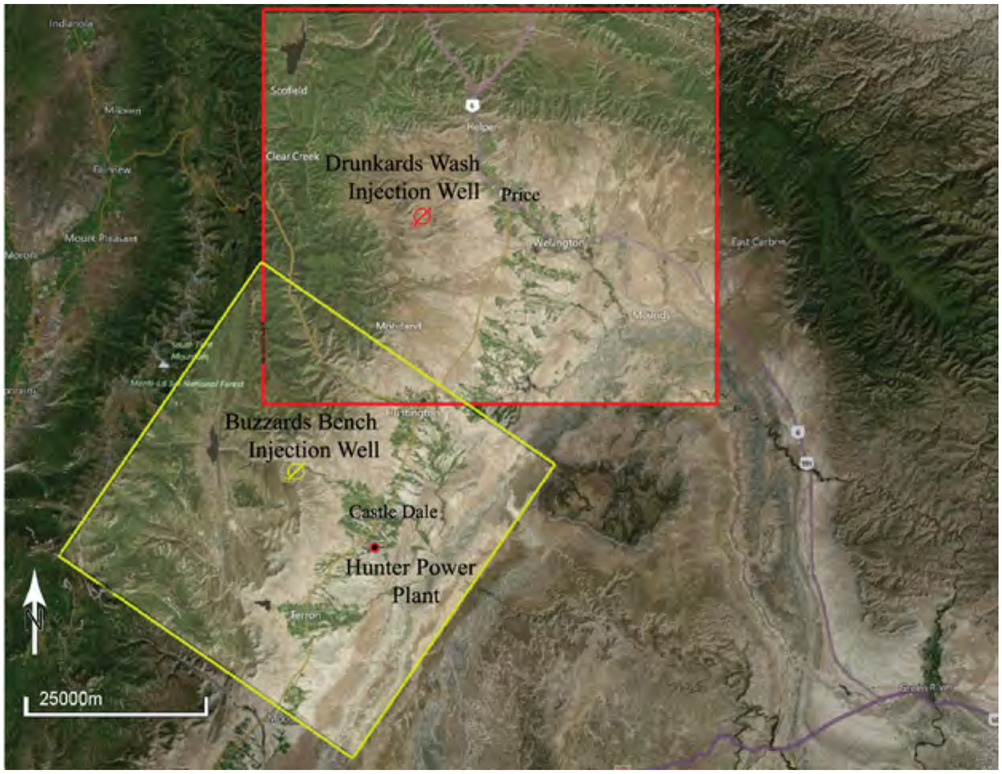

Figure 15. Regional overview of the two simulation domains. Buzzards Bench domain is outlined in yellow and the Drunkards Wash domain in red.

Model Permutations

The project team has identified ranges of permeability and porosity for proposed storage formations based on literature (see Table 6).

Table 6. Variation range of permeability and porosity for Navajo, Kayenta, and Wingate formations.

	Permeability (mD)	Porosity (-)
Navajo	50 ~ 300	7 % ~ 20 %
Kayenta	10 ~ 150	7 % ~ 25 %
Wingate	50 ~ 200	7 % ~ 20 %

Based on preliminary simulation results, the project team refined the sources of uncertainty in estimating CO_2 storage at the proposed storage complex. Three factors were identified, including porosity of Navajo formation, anisotropy ratio (kz/kx) of Navajo formation, and CO_2 injection rate. Specific reasons for selecting these factors are listed below.

(1) Only the Navajo formation was considered as a source of uncertainty, while the underlying Kayenta and Wingate formations were not treated as primary sources of uncertainty at this stage. Because injection occurred at the Navajo formation and most of CO_2 stayed in this formation, only a small amount of CO_2 migrated to deeper formations (i.e., Kayenta and Wingate).

(2) Considering the correlation between porosity and permeability, only porosity was considered as an independent source of uncertainty, while permeability was derived from porosity using empirical relationship.

(3) Three different injection rates were used to achieve the goal of 50 million tons of CO_2 storage.

With Box-Behnken Design (BBD), a total of 13 realizations were designed to cover the uncertainty space based on three uncertainty factors (shown in Figure 16). Details of the realizations are listed in Table 7, where -1,0, and 1 represent three equally spaced values. Table 8 presents the values for uncertainty factors and associated dependent model settings (permeability and injection duration) for the 13 realizations. These values were populated to both storage sites, the Buzzard Bench site and the Drunkards Wash site. A total of 26 realizations was simulated with the Eclipse E300 module.

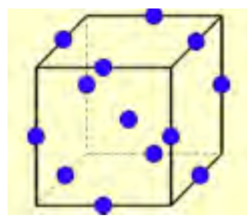

Figure 16. Diagram showing Box-Behnken-Design with three uncertainty factors.

Table 7. A list of 13 realizations formulated by BBD with three uncertainty factors.

Sim#	X1 (Porosity)	X2 (kz/kx)	X3 (Inj. Rate)
1	-1	-1	0
2	1	-1	0
3	-1	1	0
4	1	1	0
5	-1	0	-1
6	1	0	-1
7	-1	0	1
8	1	0	1
9	0	-1	-1
10	0	1	-1
11	0	-1	1
12	0	1	1
13	0	0	0

Table 8. Values of uncertainty factors and associated model settings for the 13 realizations.

Sim#	X1 (vol/vol)	X2 (mD/mD)	X3 (million tonnes per year)	Permeability (mD)	injection duration (year)
1	12%	0.05	2.5	17.16	20
2	20%	0.05	2.5	636.01	20
3	12%	0.5	2.5	17.16	20
4	20%	0.5	2.5	636.01	20
5	12%	0.275	1.67	17.16	30
6	20%	0.275	1.67	636.01	30
7	12%	0.275	5	17.16	10
8	20%	0.275	5	636.01	10
9	16%	0.05	1.67	131.24	30
10	16%	0.5	1.67	131.24	30
11	16%	0.05	5	131.24	10
12	16%	0.5	5	131.24	10
13	16%	0.275	2.5	131.24	20

Injection Well Locations & CO_2 Injection

Initially, three different CO_2 injection well locations were explored, directly under the power plant, the Buzzards Bench site west of the power plant, and the Drunkards Wash site north of the power plant. The well at the power plant was located on Hunter property while the rest of the well locations evaluated are sited on State of Utah School and Institutional Trust Lands Administration (SITLA) land (Figure 17 and Figure 18). Initial results showed that CO_2 injected under the Hunter Power Plant property migrated close enough to the Navajo Sandstone outcrops to exclude it from further consideration. Due to this, the two additional well location was the focus of the rest of this study.

The Buzzards Bench #1 well is about 9 miles northwest of the power plant. It is perforated at the Navajo Sandstone interval, from 7471 feet to 7616 feet. This site is about 22 miles from where the Navajo Sandstone outcrops and we believe this will provide sufficient to contain the CO_2 plume.

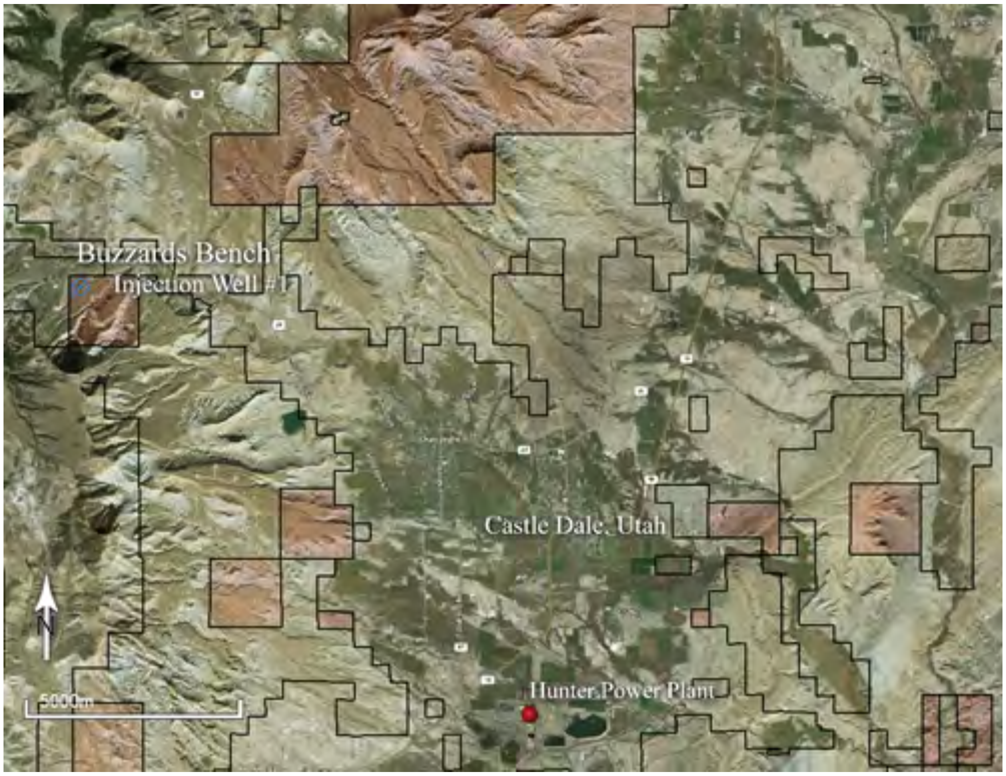

Figure 17. The proposed location for the Buzzards Bench CO_2 injection well. The well is located just over 8.5 miles (14 km) northwest from the Hunter Power Plant on SITLA land (highlighted with orange).

The Drunkards Wash #1 well is located 28 miles north of the Hunter Power Plant on SITLA land (Figure 18). The well is perforated in the Navajo Sandstone at an interval of 7202 feet to 7519 feet. This well location has an advantage over the Buzzards Bench site in that the reservoir and caprock do not outcrop in the vicinity, reducing the risk of loss of CO_2 containment.

Carbon dioxide injection occurred at three different rates, a low rate of 1.67 million tons per year for 30 years, a medium rate of 2.5 million tons per year for 20 years and a maximum rate of 5 million tons per year for ten years. This injection scheme is designed to ensure that 50 million tons of CO_2 are injected into the reservoir during the simulation. Table 8 shows the injection rate and duration for each of the 13 simulations.

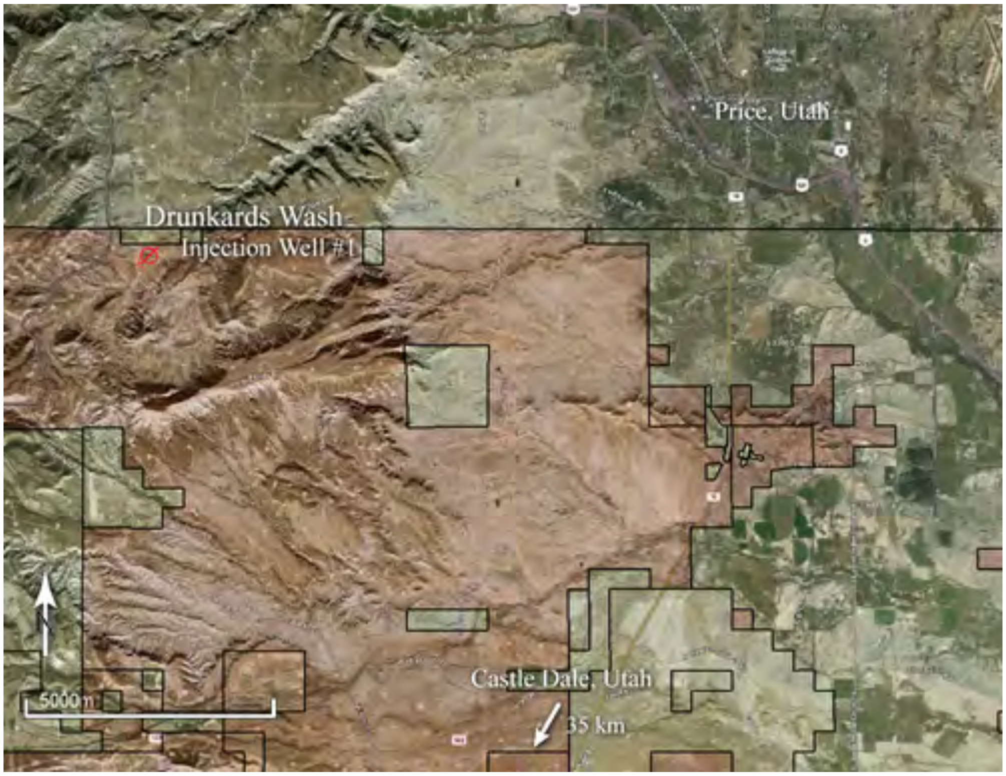

Figure 18. The proposed location for the Drunkards Wash CO_2 injection well. This well is located 28 miles (45 km) north of the Hunter Power Plant in the Drunkards Wash gas fields on SITLA land (highlighted with orange).

Results

Results show that regardless of the model permutation, the reservoir can accommodate just under 50 million tons. Figure 19 and Figure 20 indicates that the limiting factor for CO_2 injection in these models is the injection rate and duration. At both sites, the reservoir properties do not limit the injection rate under any of the model permutations. Under all scenarios, the injected CO_2 is contained within the target formation, and there is no significant migration towards the outcrops.

At the Buzzards Bench site, CO_2 migrates slowly towards Castle Dale and the Navajo outcrop 13 miles to the east. Over the 100 years simulated the plume only moves a couple of kilometers towards the outcrop (Figure 21). At that rate, it could take more than 1300 years for the plume to reach the outcrop. More than likely the CO_2 will have all dissolved into the formation brine and become immobilized before then. This slow plume movement indicates that this is a suitable storage site for CO_2.

At the Drunkards Wash site, the CO_2 migrate to the southwest, away from any potential outcrops to the southeast (Figure 22). From this standpoint, this site is a better storage candidate than the Buzzards Bench site. It has the storage capacity for at least 50 million tons of CO_2 and has better containment potential than Buzzards Bench. The downside is that it is much further away from the Hunter Power Plant, increasing transportation-related costs.

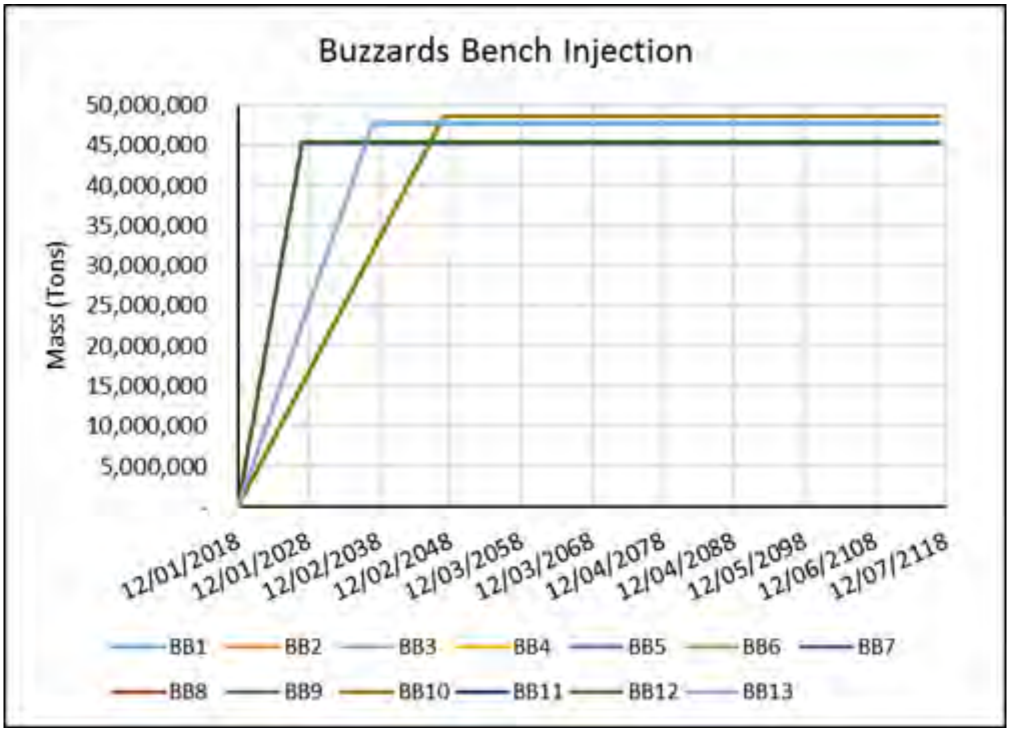

Figure 19. Cumulative CO_2 injection mass (in tons) for the Buzzards Bench injection site.

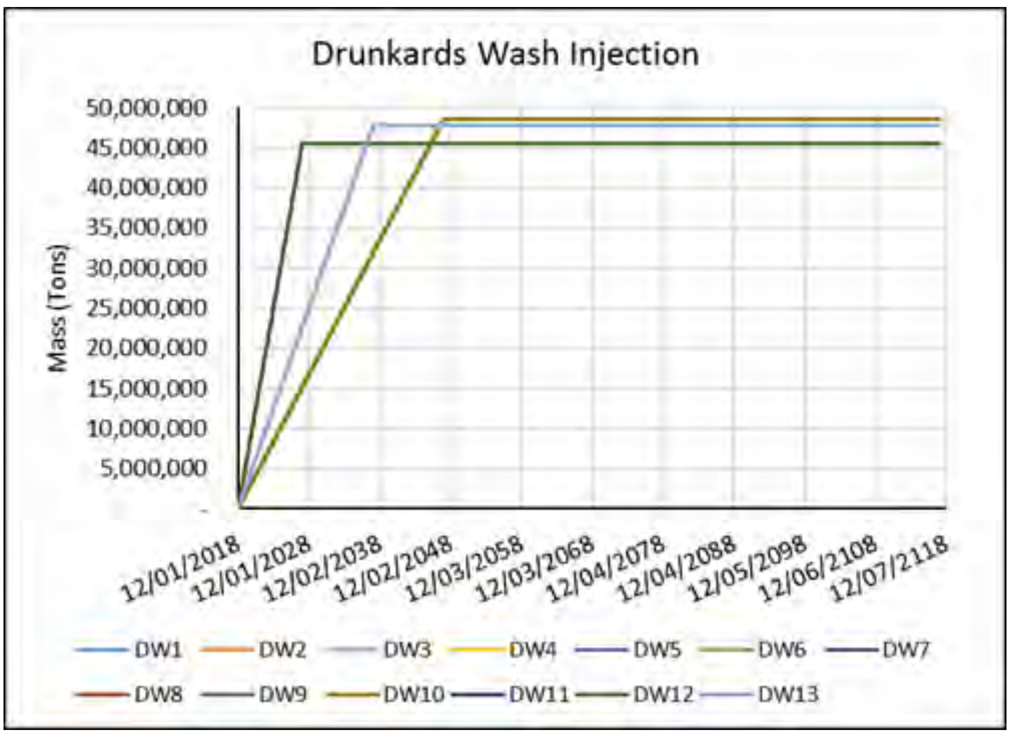

Figure 20. Cumulative CO_2 injection mass (in tons) for the Drunkards Wash injection site.

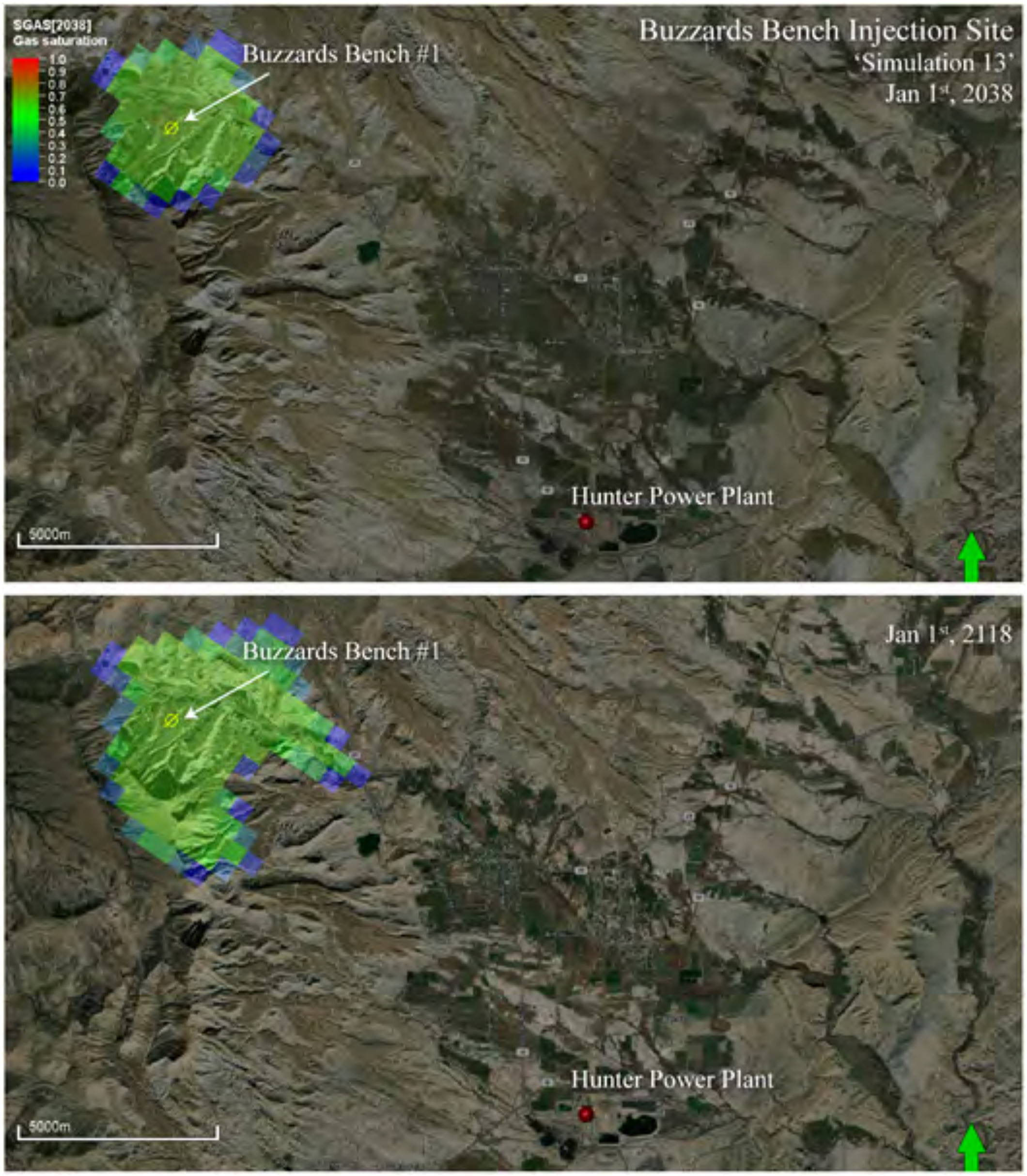

Figure 21. This plot shows the gas saturation results for the Buzzards Bench domain at the end of injection (2038) and the end of the simulation (2118) for simulation permutation #13. This simulation permutation represents the medium injection time along with the medium porosity/permeability and anisotropy. See Table 8 for simulation parameters.

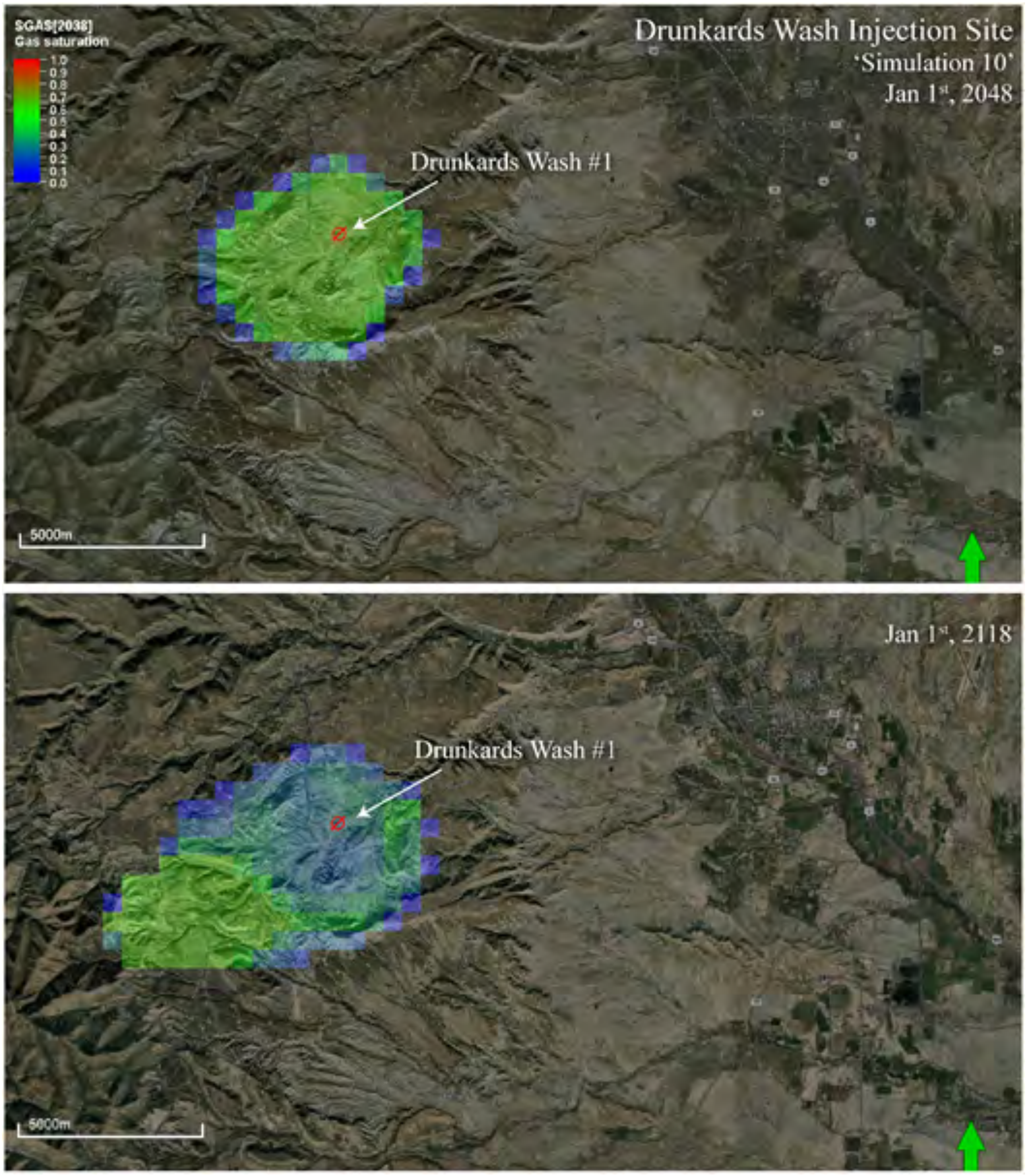

Figure 22. This plot shows the gas saturation results for the Drunkards Wash domain at the end of injection (2038) and the end of the simulation (2118) for simulation permutation #13. This simulation permutation represents the medium injection time along with the medium porosity/permeability and anisotropy. See Table 8 for simulation parameters.

Simulation results from the 26 permutations were further analyzed in Section 3.3.1 and Section 3.4.2.

3.2.3 Regional Geologic Carbon Storage Model

The third major simulation model permutation developed during this study was a regional capacity model. The model encompassed both of our possible injection sites, Buzzards Bench and Drunkards Wash, into a single model domain (Figure 23). This was done for a couple of reasons. Foremost was that the results from the NRAP simulations indicated that the very edge of the pressure plume was reaching the boundaries of the model. We did not believe this was having enough of an impact to warrant re-running all of the NRAP simulations. Another reason for this larger model was to explore the overall capacity of this area beyond just the 50 million tons mandated by this project. We wanted to begin to address the question *"Can this area be used as a regional geologic carbon storage site for all of the point source CO_2 emissions in Utah?"*

Large Domain Model Development

Analysis of the NRAP wellbore leakage modeling indicated that the Buzzards Bench and Drunkards Wash model domains were too small for effective analysis. Specifically, the pressure plume consistently reached the model boundaries, and thus the boundary conditions were compromising the model results. A larger dynamic model domain was delineated that encompassed both the Buzzards Bench and Drunkards Wash injection sites to resolve this issue (Figure 23, section outlined in blue). This domain measures 44 miles by 62 miles and includes the Carmel formation (overlying seal unit), the Navajo Sandstone (primary reservoir), the Kayenta Formation (secondary reservoir), the Wingate Sandstone (tertiary reservoir), and the Chinle Formation (underlying sealing unit). The model is discretized into 1,053,864 active cells.

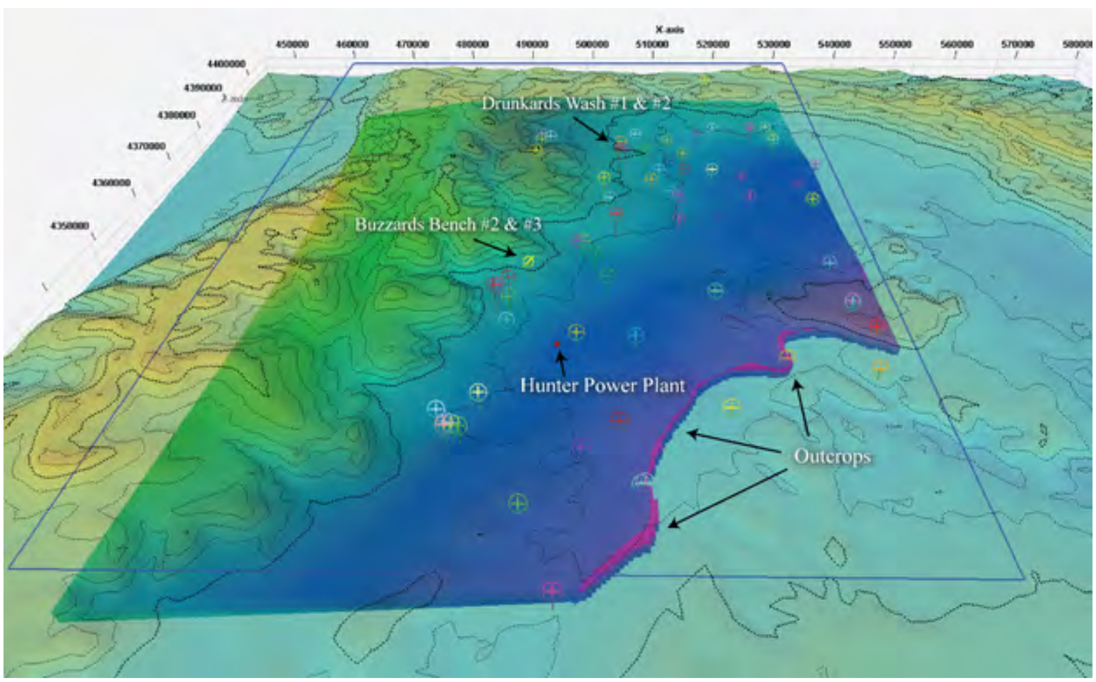

Figure 23. This figure shows the surface topography overlain on the simulation model domain. The wells used to delineate the stratigraphic horizons are shown as circles with pluses in them, and the project wells are indicated with a circle with an arrow through it.

A total of 77 wells have well top data that extends below the Navajo Sandstone and are thus critical for accurately modeling the stratigraphic interval of interest. During the model building process, we identified issues with formation top picks in some of these wells. These were not an issue for the previous modeling work as they were all outside the model domains. This new model domain encompasses a much larger area and a few wells with incorrect formation top picks were adversely affecting model creation. All 77 wells had to each be checked to ensure that the formation top picks were in the proper stratigraphic order and if well logs were available, the formation top picks were matched to these well logs to fix any obvious errors. Figure 23 shows the model domain with the surface topography and the 77 wells used to create the horizons. The southeast portion of the model was truncated along an area where the Carmel and Navajo Sandstone outcrop. The area where the formations outcrop is indicated along with the location of the Buzzards Bench and Drunkards Wash wells.

Permeability and Porosity Data

Petrophysical properties and outcrop analysis done by the characterization group indicates that the Navajo Sandstone consists of three major horizons. Figure 24 shows a select group of well logs for SWD #1 (salt water disposal well) alongside the zone delineation being modeled for the Navajo. Three major horizons can be seen from these logs and were also observed in the outcrop study. The dynamic model has three zones delineated so that representative petrophysical properties can be assigned to each.

Table 9. Porosity and permeability assigned to each of the formation being modeled.

	Carmel	Navajo	Kayenta	Wingate	Chinle
Porosity	2.0%	12.3%	8.0%	10.0%	2.0%
Permeability (mD)	0.02	38.9	10.0	60.0	0.02

Porosity and permeability data collected as part of the characterization effort was incorporated into the dynamic model. Legacy data from two wells about 45 miles southwest of Hunter, Wolverine Federal No. 17-2 and No. 17-3, and one of the salt water disposal wells, SWD #1, provided porosity and permeability measurements with depth. Porosity and permeability were also measured from outcrop samples taken from Buckhorn Wash in the San Rafael Swell area. This data was then used to create a homogeneous porosity and permeability model. Each of the three zones in the Navajo was assigned the same homogeneous porosity and permeability distribution. Table 9 shows the values assigned to each of the five formations being modeled; the Carmel, the Navajo, the Kayenta, the Wingate, and the Chinle. Data for the formation other than the Navajo was from the literature as there was not any petrophysical analysis done by the characterization group or provided in the well logs that could provide meaningful values. These values are consistent across all model cases.

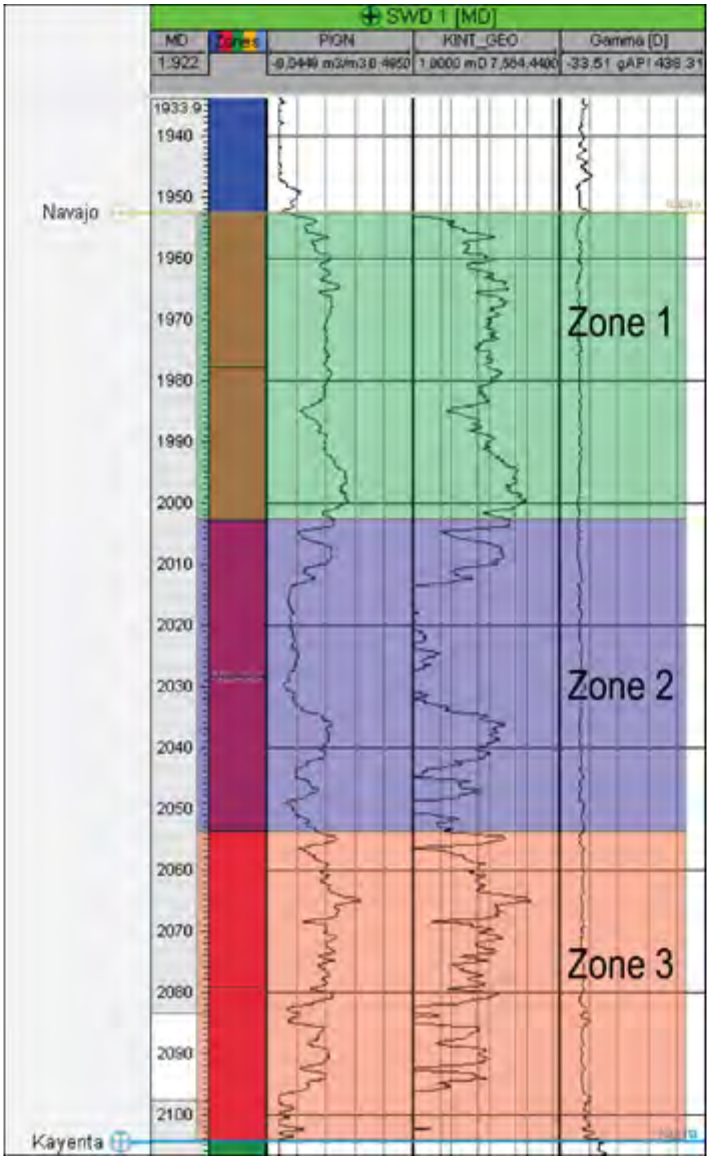

Figure 24. Navajo Sandstone interval from the well logs for SWD#1. This highlights the three major horizons showing a clear difference between the bottom, middle and top of the Navajo Sandstone.

Relative Permeability and Capillary pressure

Relative permeability and capillary pressure measured on Navajo Sandstone core by the characterization group was incorporated into the dynamic model. Three relationships were measured, one for each of the three zones identified in core and outcrop samples from the Navajo Sandstone. These three relative permeability and capillary pressure relationships were then incorporated into the dynamic simulation model for each of the three zones. Due to a lack of data in the literature, the Wingate Sandstone and the Kayenta Formation were assigned a 'default' curve for sandstone from Petrel©, and the capillary pressure was estimated using van Genuchten's formula (Pruess et al., 1999). The seal layers, Carmel and Chinle, were assigned shale relationships derived from the literature (Bennion and Bachu, 2007). Figure 25, Figure 26, and Figure 27 show the relative permeability and capillary pressure relationship assigned to the three zones within the Navajo Sandstone.

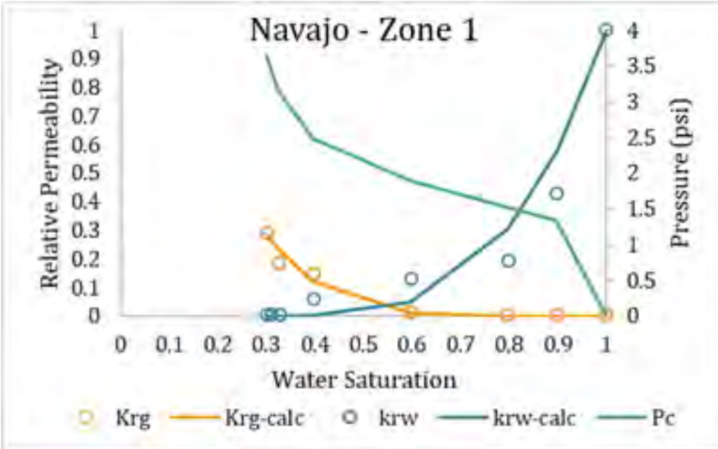

Figure 25. Relative permeability and capillary pressure relationship assigned to zone 1 (upper) of the Navajo Sandstone formation.

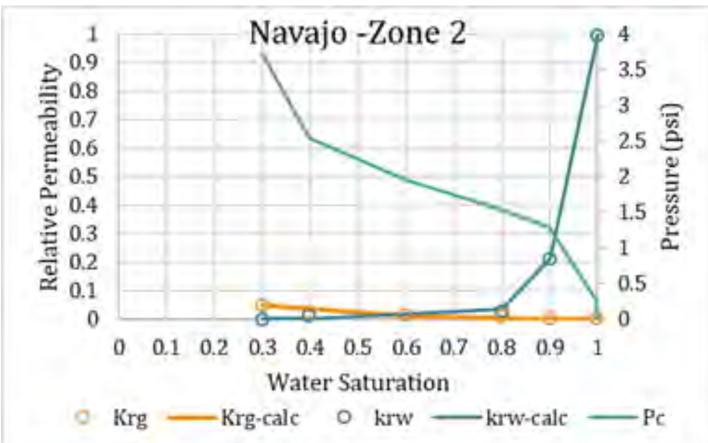

Figure 26. Relative permeability and capillary pressure relationship assigned to zone 2 (middle) of the Navajo Sandstone formation.

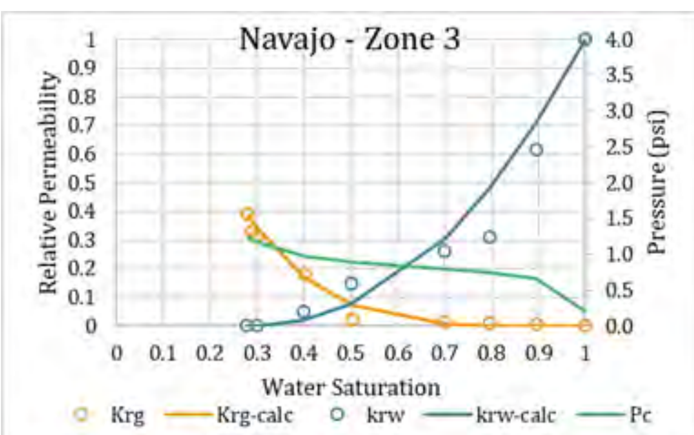

Figure 27. Relative permeability and capillary pressure relationship assigned to zone 3 (lower) of the Navajo Sandstone formation.

Boundary and Initial Conditions

The Glen Canyon Formation, which the Navajo Sandstone is part of, as well as the Carmel Formation, are regionally continuous formations across our study area and beyond. The boundary conditions for the large domain model needed to mimic this extensive lateral extent. The four lateral boundaries are set to infinite volume cells so that a constant head is maintained. The top and bottom boundaries are set to no flow as we did not observe any indications of vertical fluid migration from the Navajo through the Carmel. The outcrop area is modeled as an aquifer recharge zone for the Navajo Sandstone with a constant flux of $2.7e^{-5}$ m^3/day of fresh water. That recharge rate equates to roughly 3000 acre-ft/year over the whole San Rafael Swell, about 93,000 acres (Hood and Patterson, 1984).

The initial pressure distribution was set to hydrostatic conditions. The model was then simulated for 1000 years with only the aquifer recharge zone active to create the pre-exploration initial conditions. This pressure distribution was then applied to a second model case that simulates the historic saltwater injection occurring in Buzzards Bench area from January 1996 to January 2018. The results of this simulation set up the initial pressure and water saturation distribution that was used as the initial conditions for all subsequent model cases. Figure 28 shows this 'initial conditions' pressure distribution.

Model Permutations

We created five simulation cases using this large domain model. The first case (Buzzards Bench 50MT) injected CO_2 at the Buzzards Bench site at a rate of 2,347,358 m^3/day for 30 years, and then the plume movement was monitored for an additional 70 years. The goal of this case was to explore the feasibility of storing 50 million tons of CO_2 within the vicinity of the Hunter Power Plant. The second case (drunkards Wash 50MT) injected CO_2 at the Drunkards Wash site at the same rate and duration as the Buzzards Bench case. The goal of this case was similar to the first case but with the idea of leveraging surface infrastructure, pipeline rights of way and well pads, that are in the Drunkards Wash area. The third case (Buzzards Bench Capacity) injected CO_2 at the Buzzards Bench site at the maximum rate the formation will allow with a bottom-hole pressure limit of 4780 psi for 30 years. This case explores the total amount of CO_2 that can be injected at the Buzzards Bench site if the injection rate is determined by the injectivity of the formation. The fourth case (Buzzards Bench & Drunkards Wash Capacity) injected CO_2 using the same bottom hole pressure limiting injection scheme as the third case but at both injection sites. The fifth case (Regional Capacity) injected CO_2 into 21 wells spread across the model with the goal of injecting all of the anthropogenic CO_2 that Utah produces from point-source emitters. This case explores the question '*Is there capacity to store all of the CO_2 that Utah emits from point sources like power plants and other heavy industry?*' Table 10 lists the point-source CO_2 emitters in Utah, what industry they are a part of, and their annual CO_2 emission in millions of tons per year. This data was used to create the injection schedules for this model case.

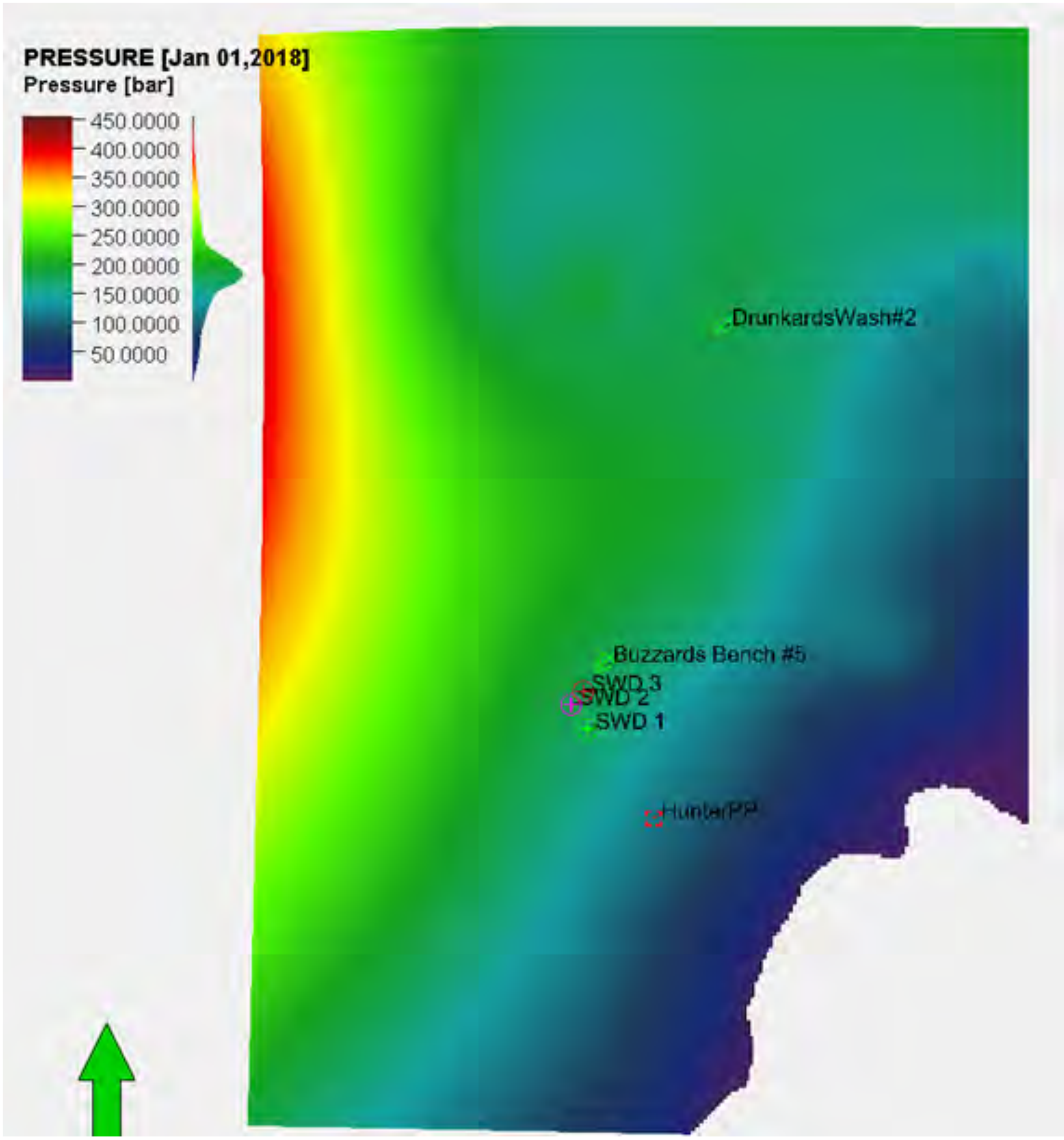

Figure 28. The pressure distribution used as initial conditions for all subsequent models.

Table 10. CO_2 sources used to build the injection schedule for the 'Regional CCS' simulations.

CO_2 Emissions from Point Sources in Utah		
Source Name	Source Type	Emissions ($MtCO_2/y$)
Deseret Power	Fossil Fuel Electric Power Generation	3
Carbon Power Plant	Fossil Fuel Electric Power Generation	1.2
Currant Creek Power Plant	Fossil Fuel Electric Power Generation	0.8
Hunter Power Plant	Fossil Fuel Electric Power Generation	8.8
Huntington Power Plant	Fossil Fuel Electric Power Generation	6.2
Intermountain Power Project	Fossil Fuel Electric Power Generation	8.8
Lake Side Power Plant	Fossil Fuel Electric Power Generation	1.2
Sunnyside Cogen Associates	Fossil Fuel Electric Power Generation	0.5
Total Power Generation		30.5
Linde Gas North America LLC	Industrial Gas Manufacturing	0.1
Nucor Steel	Iron and Steel Mills and Ferroalloy Manufacturing	0.1
Big West Oil LLC	Petroleum Refineries	0.3
Chevron Products Co.	Petroleum Refineries	0.5
Holly Refining & Marketing Co.	Petroleum Refineries	0.3
Tesoro Refining and Marketing Co.	Petroleum Refineries	0.5
Ash Grove Cement Co.	Cement Manufacturing	0.4
Lafarge Holcim Devil's Slide	Cement Manufacturing	0.6
Total non-Power Generation		2.8
Total Emissions		33.3

Injection Well Location and Schedule

When we were exploring injection well locations, there were a number of things to consider, distance from the Hunter Power Plant, depth to the injection zone, distance to any known outcrops, and surface land ownership. The ideal location for the CO_2 injection wells would be at the Hunter Power Plant site. Unfortunately, this location is too close to where the Navajo and Carmel outcrop for long-term CO_2 storage. Simulations showed that under certain reservoir conditions CO_2 will flow towards the outcrop 13 miles away and would eventually be released to the atmosphere. This injection site was deemed not suitable for long-term CO_2 storage, and alternative sites had to be considered.

For the 'Buzzards Bench 50MT' and 'Drunkards Wash 50MT' simulation cases two wells per injection location were deemed necessary. Engineers on the project indicated that an injection well has a physical rate limit of 1 million tons of CO_2 per year. This limit requires two wells per site to handle the injection rate of 2,347,358 m^3/day (1.87 MT/yr) needed to store 50 million tons in 30 years. The injection wells at each site are perforated across the entire Navajo Sandstone interval and modeled as deviated wells, sharing the same well pad but becoming 1 km apart at the injection interval. The injection wells at both project location were relocated to sites of abandoned wells within SITLA property boundaries. Moving sites was done to leverage existing surface infrastructure and ensure that wells are located in areas that can be accessed by drilling rigs. Figures 25 and 26 in Appendix I show the locations of each of these injection wells.

The 'Buzzards Bench Capacity' and the 'Buzzards Bench & Drunkards Wash Capacity' cases use the same well locations as the 'Buzzards Bench 50MT' and 'Drunkards Wash 50MT' cases. Unlike the previous cases, these two cases specify a bottom hole pressure limit and let the wells flow at the maximum rate that the formation will accept. These cases do not consider the engineering limit of 1 million tons per year for each well, allowing the wells to inject at a much higher injection rate. Figure 29 shows the injection rates for these four cases.

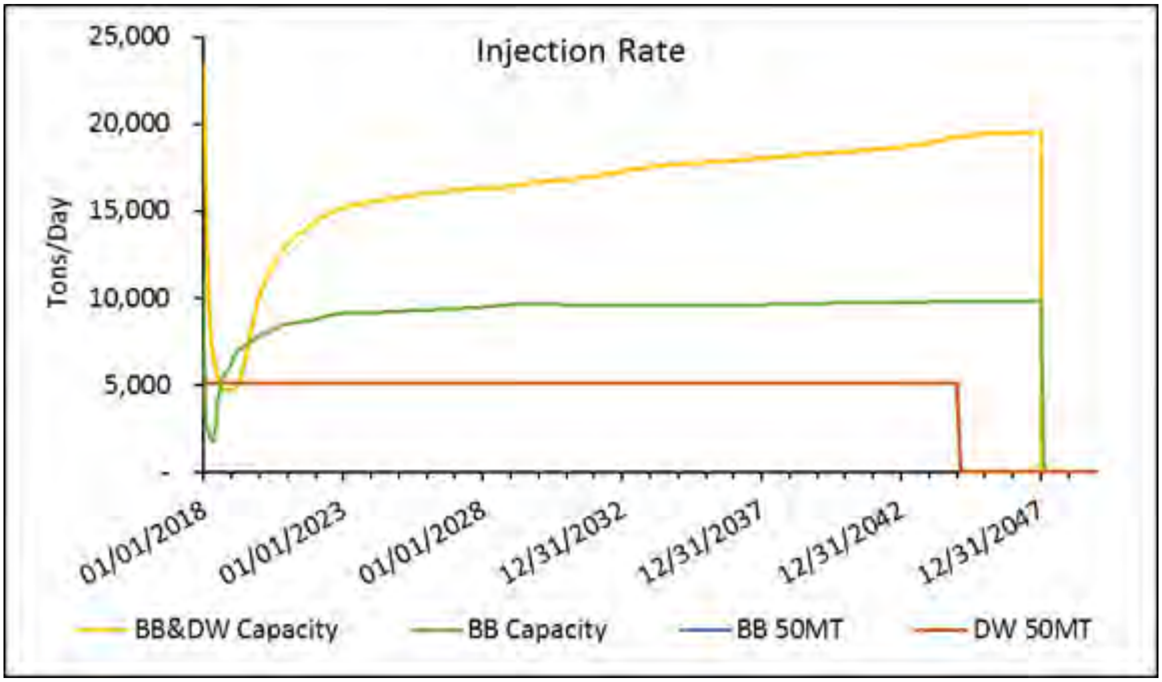

Figure 29. Injection rates for the Buzzards Bench 50MT case (BB 50MT), the Drunkards Wash 50MT case (DW 50MT), the Buzzards Bench Capacity case (BB Capacity) and the Buzzards Bench & Drunkards Wash case (BB&DW Capacity).

In addition to the CO_2 injection wells, there are two saltwater disposal wells near the Buzzards Bench injection site that inject waste water from the overlying Ferron Sandstone gas deposits. These wells show current, as of February 2018, wastewater injection, so they are modeled with continuing injection of wastewater for an additional 20 years.

The fifth case models the area as a regional geologic carbon storage site. The emission data from Table 10 was used as the injection targets for this case. A total of 33.3 million tons of CO_2 needs to be injected annually. With a maximum injection rate of 1 million tons per year per well we needed 21 wells to accommodate that mass of CO_2. In addition to the four project wells, 17 other well locations were identified along the corridor from the Hunter Power Plant to the Drunkards Wash injection site (Figure 30). These are the sites of current plugged and abandoned wells. The injection schedule has stepped down injection targets through time. We attempted to model a gradual phase-out of fossil fuel power generation through the first 50 years of the simulation. For the next 50 years, there is just injection of emissions from heavy industry. By 2118 all CO_2 injection stops with the idea that we have figured out how to run heavy industry without fossil fuels. Table 11 shows the injection rate, the number of wells needed to inject that rate, and the data that injection rate stops. Figure 31 graphically shows the injection wells and their duration of CO_2 injection. Comparing the wells shut-off dates in Figure 31 to the map of the well locations in Figure 30 shows that the wells in the southern portion of the field, around the

Buzzards Bench area and south, are shut off first with the wells in the Drunkards Wash area shut off last. This was done because the reservoir does not outcrop in the Drunkards Wash area and thus the risk of CO_2 leakage to the surface is less. In the southern portion of the field, there is a greater potential for CO_2 to reach the outcrops and escape to the atmosphere.

Table 11. Injection rate targets through time for the 'Regional Capacity' case.

Injeciton Rate (MT/yr)	(m^3/day)	Number of Wells	Durration (yrs)	Injection Stops
33.55	42,114,372	21	30	2048
18.50	23,222,530	21	40	2058
9.70	12,176,137	10	45	2063
6.70	8,410,322	7	50	2068
2.80	3,514,761	3	100	2118

Figure 30. Proposed well locations for the CarbonSAFE Rocky Mountain CCS project, Buzzards Bench #2 & #3 and Drunkards Wash #2 & #3 along with 17 other plugged and abandoned wells that could be used for a regional CCS site. The blue rectangle is the model boundary. The CO_2 injection wells are indicated with white labels.

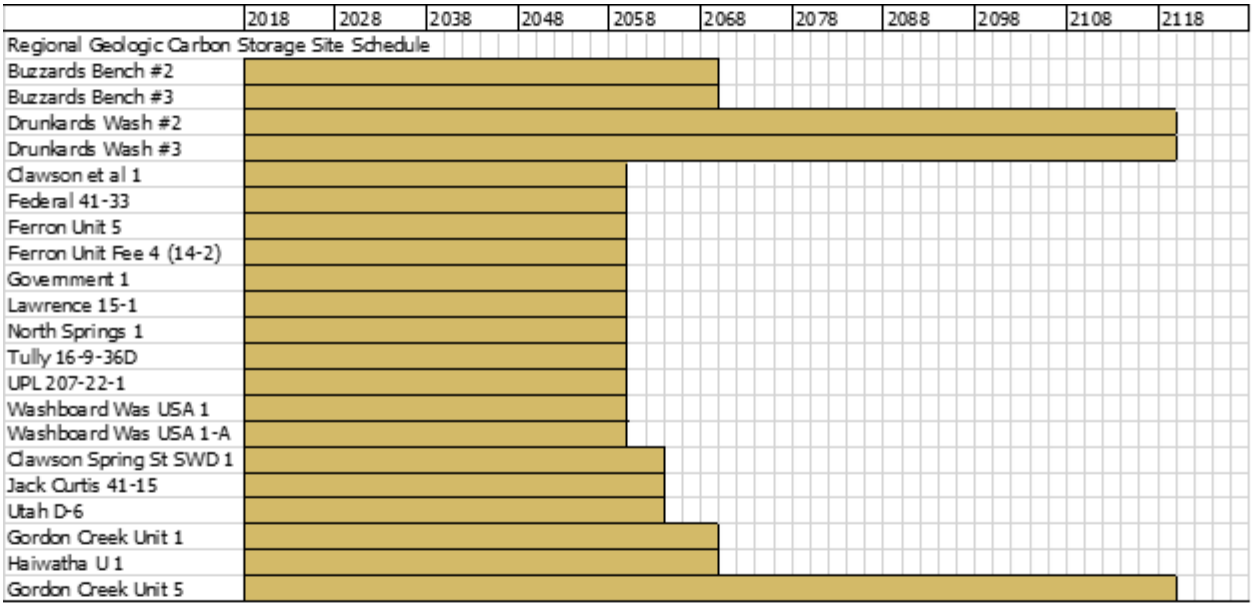

Figure 31. Injection schedule for the Regional Geologic Carbon Storage simulation.

Results

Results of this study show that it is feasible to store far more than the 50 million tons of anthropogenic CO_2 in the Buzzards Bench or Drunkards Wash area of Emery County, Utah. More than 1.4 billion tons of CO_2 were injected in the 'Regional Capacity' case, with no loss of containment over 1000 years, indicating that this area would make an ideal regional geologic carbon storage site.

Both of the '50MT' cases successfully inject slightly more than the required capture mass of 50 million tons of CO_2 (Table 12). Results of the 'Buzzards Bench 50MT' case show that 6.1 MT or about 12% of the CO_2 dissolved into the formation brine by the end of the simulation (Table 13). The 'Drunkards Wash 50MT' case showed 4% more, or about 8.2 MT CO_2 dissolving into the formation brine over 100 years (Table 13). Greater plume movement over the same period at the Drunkards Wash site is likely causing this observed difference in CO_2 dissolution. As the plume moves, the supercritical CO_2 comes into contact with unsaturated brine, resulting in higher CO_2 dissolution than at the Buzzards Bench site. The mass of supercritical CO_2 is there for higher at the Buzzards Bench site (43.1 MT) than the Drunkards Wash site (41.6 MT) (Table 14). The amount of CO_2 that is at or below residual saturation and is effectively trapped is consistent across all cases at 6%. Both injection sites will make suitable areas to store the emissions from the Hunter Power Plant.

Results of the 'Capacity' cases indicate that almost double the CO_2 can be stored in the same area. Removing injection limitation greatly increases the mass of CO_2 that can be injected (Table 12). The 'Buzzards Bench Capacity' case injected double the mass of CO_2 (101 MT) that the rate limited case did (50.5 MT). The 'Drunkards Wash & Buzzards Bench Capacity' case injected not quite double what is injected at Buzzards Bench site (Table 12). It is likely that there is less injectivity at the Drunkards Wash site because it is at a slightly shallower depth and the bottom hole pressure reaches the limit quicker. As seen in the previous cases, there is more CO_2 dissolution and at the Drunkards Wash site than at the Buzzards Bench site (Table 13).

The simulation results showed there is the capacity to store all of the anthropogenic CO_2 emission from point-sources for all of Utah. The 'Regional Capacity' case indicates that a very significant amount of CO_2 can be stored in the Castle Dale/Price area, 1.4 billion tons (Table 12). Unlike the previous cases, this case shows that 25% of the CO_2 is going to dissolve into the formation brine, leaving only 80% in the mobile phase after a thousand years. The longer simulation time, 1000 years, versus 100 years for the previous four cases, give more time for the CO_2 plume to move and contact unsaturated brine, increasing CO_2 dissolution.

Table 12. The total mass of CO_2 in tons injected into the model domain.

Total Mass CO_2 Injected [tons]	
Regional Capacity	1,412,952,644
Buzzards Bench & Drunkards Wash Capacity	180,478,080
Buzzards Bench Capacity	101,269,252
Buzzards Bench 50MT	50,525,976
Drunkards Wash 50MT	50,527,098

Table 13. The total mass of CO_2 dissolved in brine.

Total Mass Dissolved CO_2 [tons]		
Regional Capacity	357,107,434	25.3%
Buzzards Bench & Drunkards Wash Capacity	25,306,228	14.0%
Buzzards Bench Capacity	10,033,749	9.9%
Buzzards Bench 50MT	6,143,243	12.2%
Drunkards Wash 50MT	8,151,902	16.1%

Table 14. The total mass of mobile supercritical CO_2.

Total Mass Mobile Spercritical CO_2 [tons]		
Regional Capacity	1,141,116,004	80.8%
Buzzards Bench & Drunkards Wash Capacity	150,117,470	83.2%
Buzzards Bench Capacity	87,576,484	86.5%
Buzzards Bench P50	43,161,731	85.4%
Drunkards Wash P50	41,678,529	82.5%

Analysis of the CO_2 saturation distribution gave us even greater confidence in this area as an effective storage site. All simulation cases indicated that CO_2 would be effectively trapped for the foreseeable future. Analysis of the 'Buzzards Bench 50MT' case showed a plume size at the end of the simulation of about 4 km by 2 km (Figure 32). The plume doesn't migrate towards the outcrop as was expected. There are two reasons that in combination create an effective pressure barrier to up-dip migration of the CO_2 plume, the salt water disposal injection and aquifer recharge from the outcrop area. This, in turn, keeps the CO_2 plume from moving and account for the lower mass of dissolved CO_2 seen in Table 13. The CO2 plume is fairly evenly distributed vertically across the Navajo interval (Figure 32).

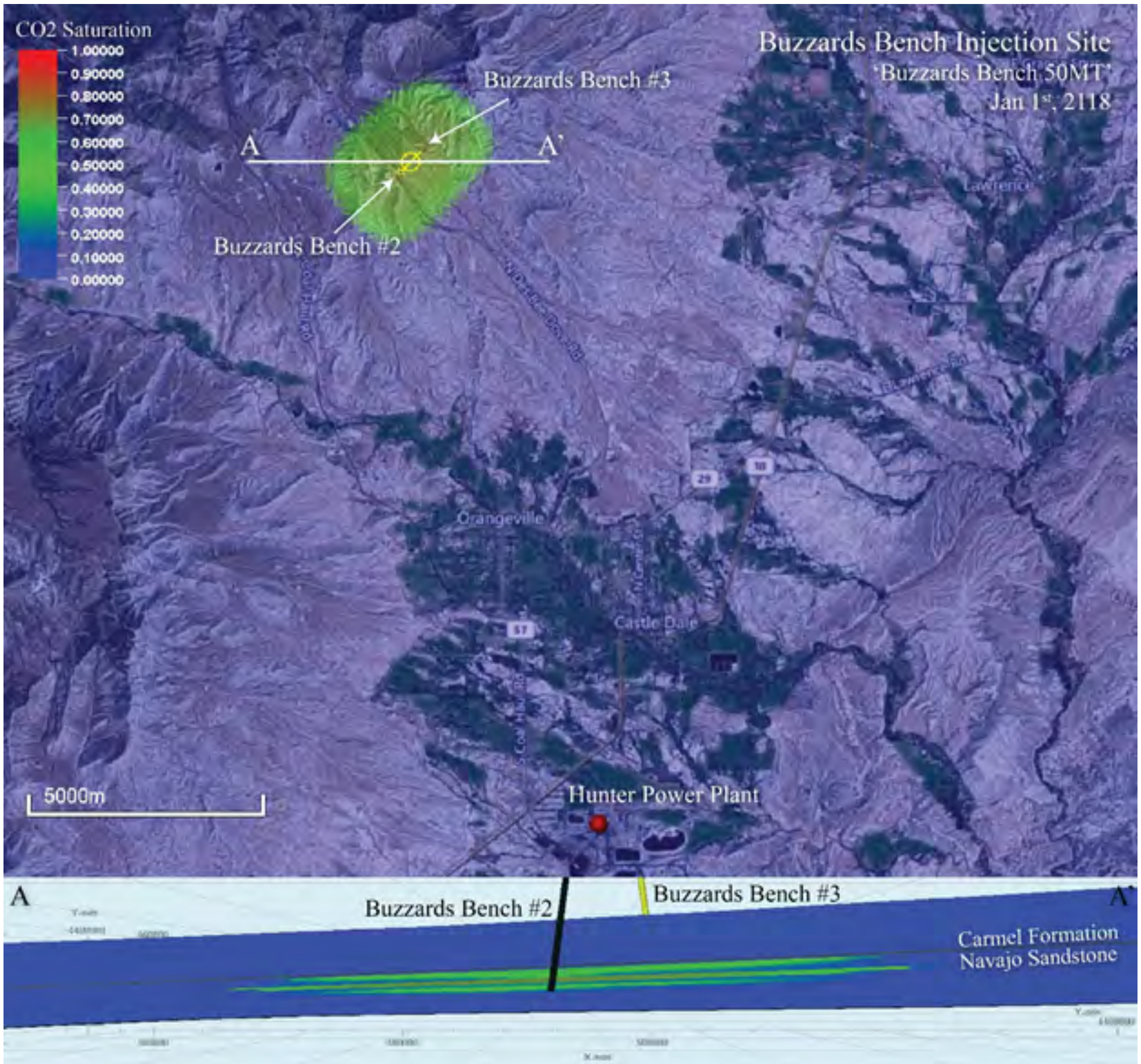

Figure 32. Results for buzzards bench at 50 MT total injection at the end of the simulation, 2118.

Results from the 'Drunkards Wash 50MT' case show a plume size of about 4 km by 2.5 km, similar in extent to what is seen in the 'Buzzards Bench 50MT' case. The main difference is that the plume has migrated about 0.5 km to the southwest, away from any potential outcrops (Figure 33). The plume movement is the reason that there is a higher fraction of dissolved CO_2 when compared to the 'Buzzards Bench 50MT' case. As with 'Buzzards Bench 50MT' case the CO_2 is evenly distributed across the Navajo interval, with the least amount of CO_2 in the middle zone and a small CO_2 in the Kayenta Formation.

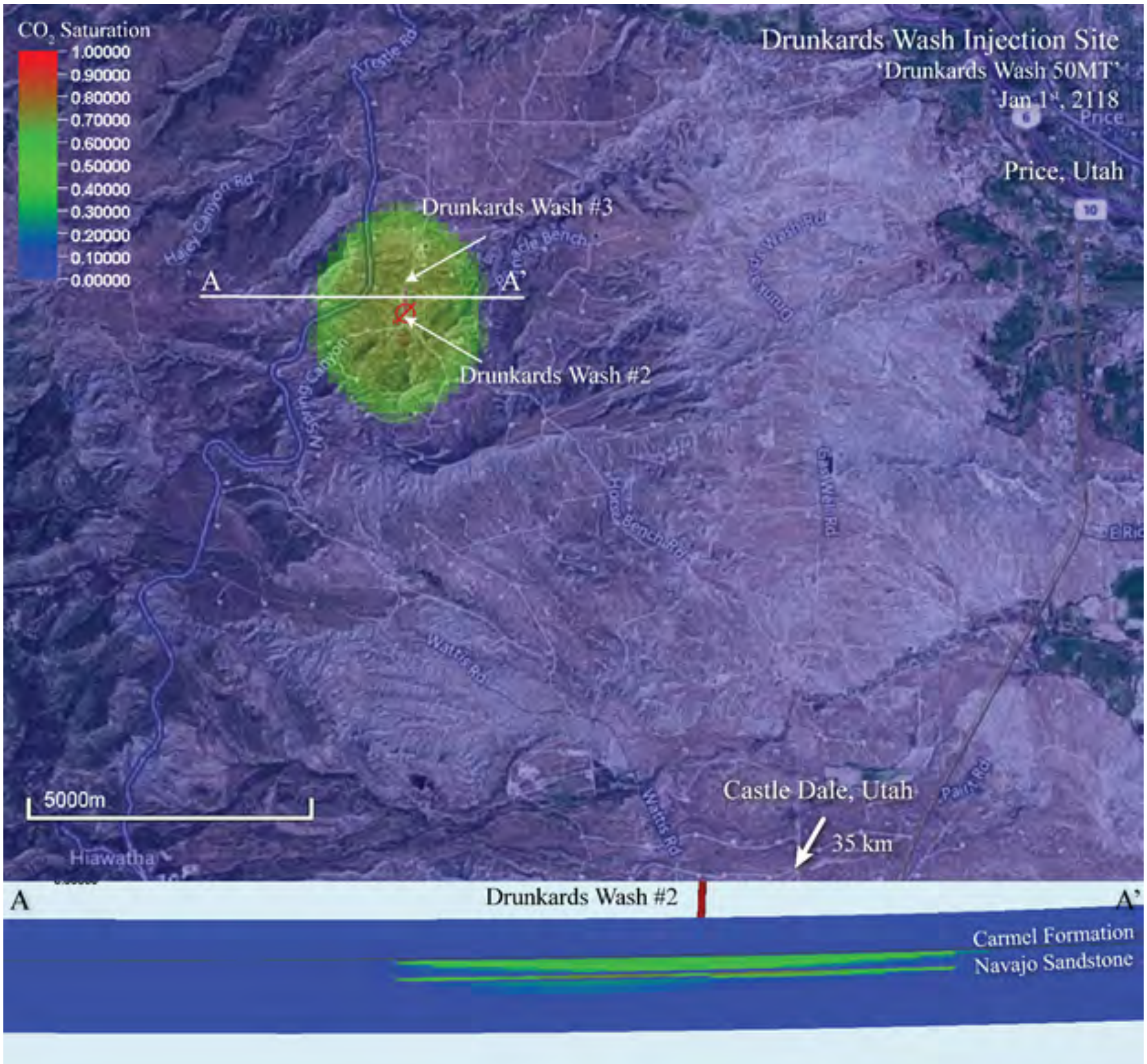

Figure 33. Results for drunkards wash at 50 MT total injection at the end of the simulation, 2118.

The saturation distributions for the 'Buzzards Bench Capacity' and the 'Buzzards Bench & Drunkards Wash Capacity' are very similar to what is seen in the previous cases. The plume sizes have increased in size a little, 4.3km x 3km at Buzzards Bench and 4.5km x 3.5km at Drunkards Wash, while the plume movement and distribution is very similar.

Analysis of the 'Regional Capacity' case shows very similar plume movement and shape as seen in all the previous cases. None of the CO_2 from any of the wells reaches the outcrops and is contained for the entire 1000-year simulation. At the end of the injection period (2118), there is very little plume movement away from the injection wells. Similar to what is seen in all previous cases (Figure 34). By the end of the simulation (3118), the CO_2 plumes have spread out laterally due to the buoyancy of CO_2 (Figure 35). There is very little lateral migration of the plumes beyond what is caused by the upward mobility of the CO_2. The plumes in the Buzzards Bench area don't move laterally more than a kilometer. The plumes generated by the three wells at the very south of the model, Ferron Unit 5, Ferron Unit Fee 4(14-2), and UPL 207-22-1, have moved a couple of kilometers to the east towards the outcrop area of the San Rafael Swell. The plume movement in the Drunkards Wash area is much larger than the rest of the model. This is likely due to the longer injection time, and consequently greater volume of CO_2 injected. There are not any outcrops in the area for the CO_2 to escape from, making this lager plume movement less of a concern.

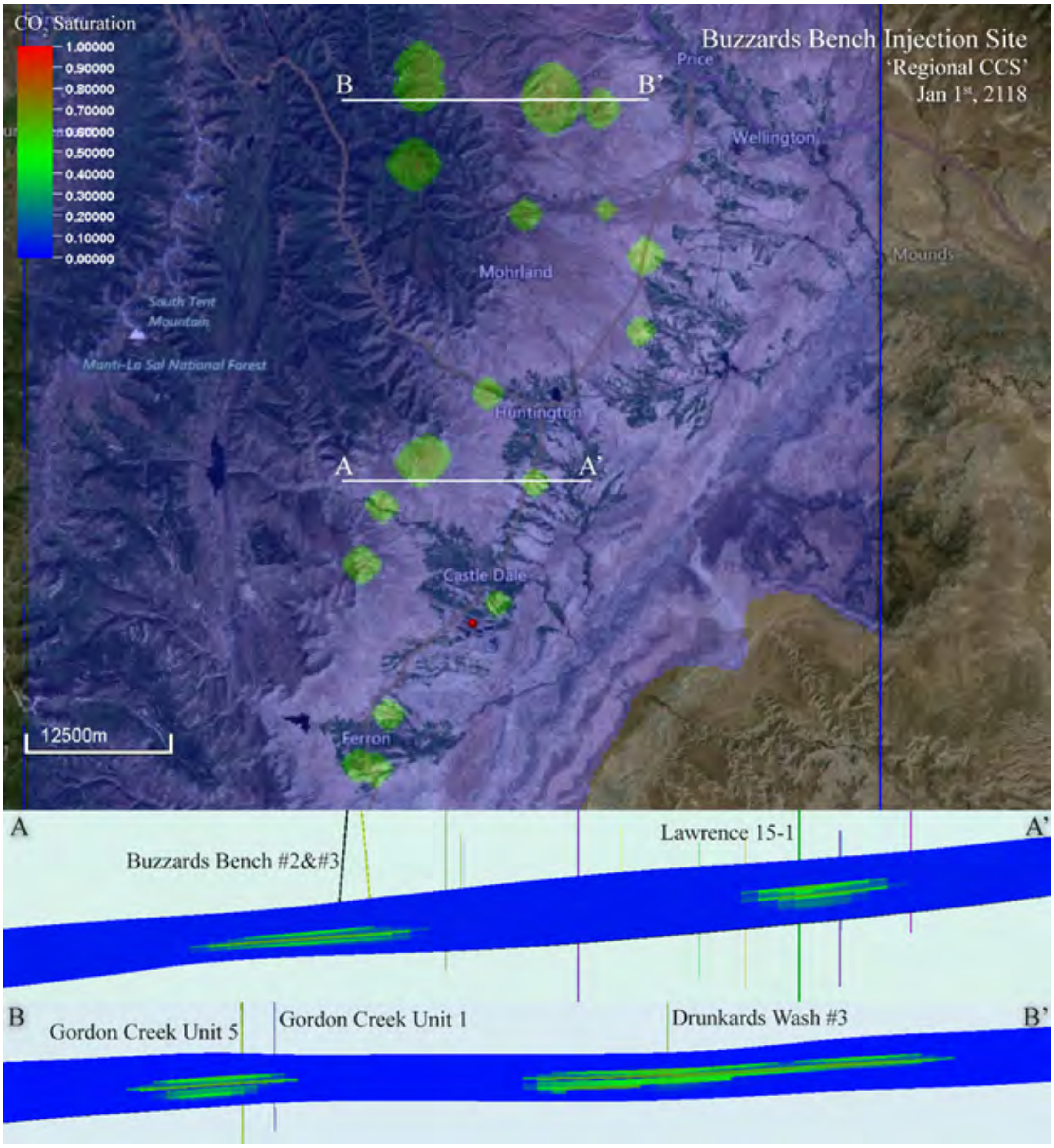

Figure 34. Results from the 'Regional Capacity' case showing the CO_2 saturation at the top of the Navajo at the end of CO_2 injection (top). Cross-sections A-A` shows the vertical $CO_2$ saturation profile in the Buzzards Bench area and cross-section B-B` shows the vertical CO_2 saturation distribution in the Drunkards Wash area (bottom).

A benefit of having two formations underlying the Navajo that are of reservoir quality is that they can accommodate additional CO_2. The injection pressure forced some of the CO_2 into the lower formations of the Kayenta and a little into the Wingate providing additional capacity. By the end of the simulation CO_2 has migrated vertically out of these reservoirs, but there is still residual CO_2 trapped in these lower formations. This all makes this area of the Colorado Plateau an ideal location for continuous CO2 injection for regional storage over a long-time period.

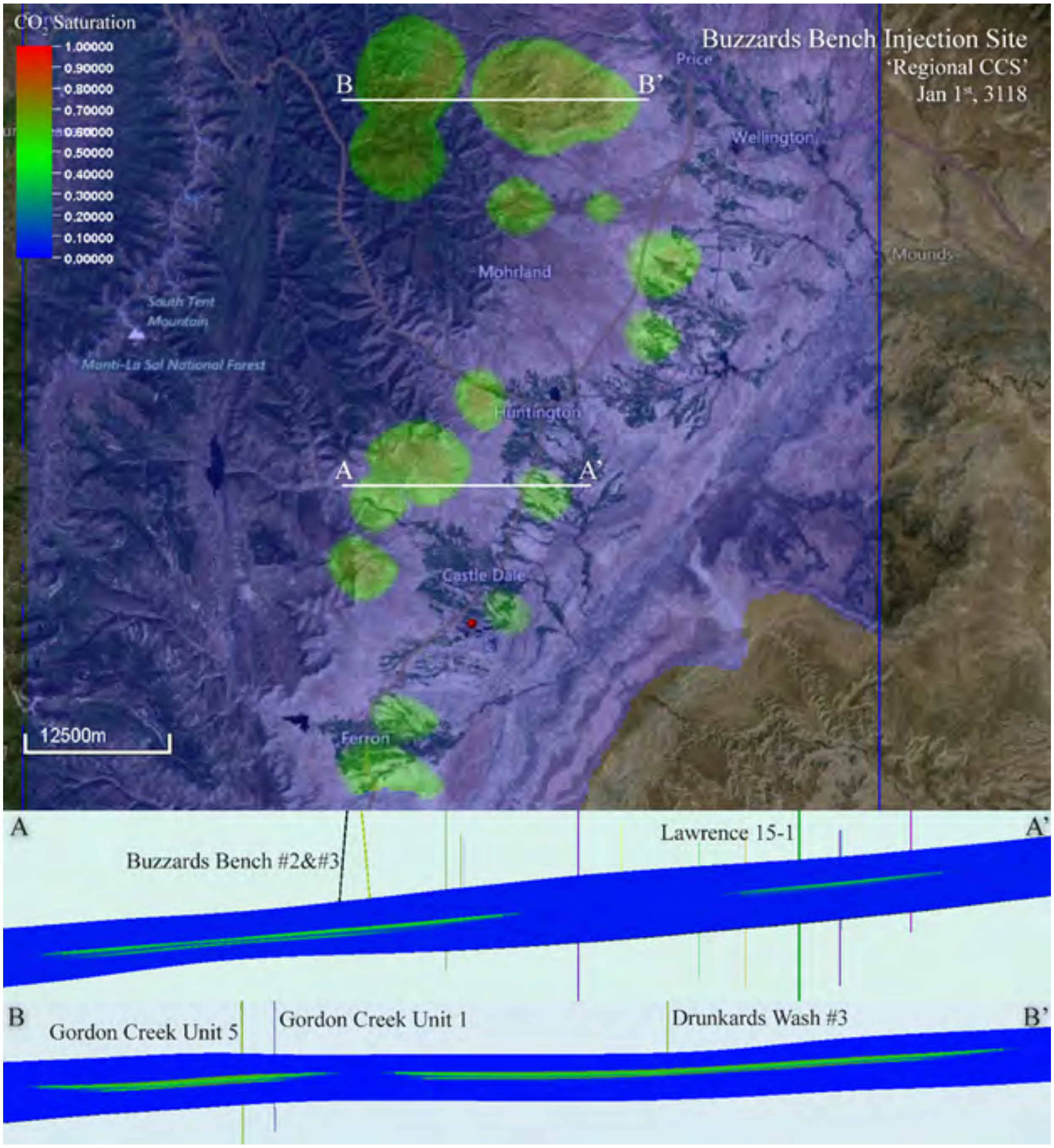

Figure 35. Results from the 'Regional Capacity' case showing the CO_2 saturation at the top of the Navajo at the end of the simulation (top). Cross-sections A-A` shows the vertical $CO_2$ saturation profile in the Buzzards Bench area and cross-section B-B` shows the vertical CO_2 saturation distribution in the Drunkards Wash area (bottom).

Conclusion and Discussion

The main conclusions of this study are as follows:

1) Both sites can effectively store the project's target amount of CO_2, 50 million tons, effectively permanently. For the Buzzards Bench area the surface water recharge and distance to the

outcrops prevents the CO_2 from escaping to the atmosphere. In the Drunkards Wash area there is no outcrop for the CO_2 to escape from and is effectively and permanently stored.

2) This area has the capacity to be a regional geologic carbon storage site. Simulations showed that this area can accommodate all the point-source anthropogenic CO_2 emission from Utah for the foreseeable future, next 100 years. The area has a total estimated capacity of over 1.4 billion tons. The injected CO_2 doesn't migrate more than a couple of kilometers and is trapped for the full 1000-year simulation.

At first glance the area to the west of the San Rafael Swell encompassing the town of Castle Dale, Utah and the Buzzards Bench and Drunkards Wash gas fields does not look like a good candidate for CO_2 sequestration. The San Rafael Swell is an anticline with the target reservoir, the Navajo Sandstone, and seal, the Carmel Formation, outcropping along its spine. It would be assumed that any CO_2 injected in the vicinity would migrate to this area and escape to the atmosphere. But after a detailed simulation study using the best characterization data we could obtain, we determined that this area would make an ideal candidate for a regional geologic carbon storage site.

3.3 AREA OF REVIEW ASSESSMENT

EPA class VI guidance documents require that an Area of Review (AOR) be designated around the potential injection well. The AOR defined as the maximum allowable pressure differential between the target reservoir and the lowest overlying USDW that will cause reservoir fluid to migrate into the overlying USDW. It assumes that there is an open well that connects the target reservoir (Navajo Sandstone) with the lowermost USDW (Ferron Sandstone) and calculates the pressure differential allowed before fluid from the target reservoir flows up the well and into the USDW. The maximum areal extent of this pressure delta and CO_2 plume extent (whichever is larger) is then mapped out to give an area that must be examined for potential well leakage.

3.3.1 Area of Review Delineation by Analytical Methods

A formula (Equation 4) and guidance on defining and calculating the area of influence from a CO2 injection well are specified in these guidance documents. Table 15 has the pressure, elevation, and fluid density information used in Equation 4.

Equation 4.

$$\Delta P_{if} = P_u + \rho_i g * (z_u - z_i) - P_i$$

Table 15. Parameters used to calculate the pressure differential for AOR delineation.

Formula Parameter			
Buzzards Bench	Drunkards Wash		
12,575,444	10,621,088	P_u	USDW Pressure
22,364,000	21,801,300	P_i	Reservoir Pressure
1020	1020	Rho_i	Reservoir Fluid Density
711	881	z_u	Elevation of USDW
-326	-232	z_i	Elevation of Reservoir

When Equation 4 is solved for our storage site, it shows that we have a near hydrostatic condition at Buzzards Bench and a slightly over pressurized condition at Drunkards Wash (Table 15). The guidance documents stipulate that if Equation 4 indicates a hydrostatic condition, then numerical simulation must be used to determine the AOR. A suite of simulations was then designed and executed to address the AOR requirement. See sections 3.2.2 and 3.3.2 for details on model design and results.

Table 16. Pressure delta results using the EPA formula.

DeltaP Buzzards Bench	
583,671	Pa
5.84	bar
Drunkards Wash	
-46,713	Pa
-0.47	bar

3.3.2 Area of Review Delineation and Risk Assessment with NRAP Tools

U.S. Environmental Protection Agency's (EPA's) Class VI regulations require owners or operators of carbon storage projects to determine an Area of Review (AoR) representative of project risk to underground sources of drinking water (USDWs). The AoR is an estimate of the region potentially impacted by the CO_2 injection and is used to develop monitoring plans to ensure protection of USDWs.

For this study, the approach is to use the National Risk Assessment Partnership (NRAP) tools developed by the U.S. Department of Energy (DOE) for quantitative risk assessment of geologic sequestration of carbon dioxide (CO_2) (Dilmore et al., 2016; Pawar et al., 2016) to perform the risk-based AoR assessment for Buzzards Bench and Drunkards Wash two sites.

Among the NRAP toolset used for this study, the Integrated Assessment Model for Carbon Storage (NRAP-IAM-CS) adopts a stochastic approach in which predictions address uncertainties in storage reservoirs, leakage scenarios, and shallow groundwater impacts. It is derived from detailed physics and chemistry simulation results that are used to train more computationally efficient models, referred to here as reduced-order models (ROMs), for each component of the system. The Reservoir Reduced-Order Model Generator (RROM-Gen) (King,

2016) is a utility program for creating reservoir ROM lookup tables to be fed into the NRAP-IAM-CS model. These tools can be used to help regulators and operators define the AoR and better understand the expected 'spatiotemporal changes of changes in water quality caused by CO_2 and brine leakage from a storage reservoir into drinking water aquifers.

Approach

The risk-based AoR calculated using the NRAP-IAM-CS model is the area where CO_2 or brine leakage from a hypothetical open (i.e., uncemented) well connecting the storage reservoir to the shallow drinking water aquifer would cause drinking water quality to change outside no-impact thresholds. For both Buzzards Bench and Drunkards Wash sites, the no-impact thresholds are pH = 6.6 and total dissolved solids (TDS) = 420 ppm (i.e., pH not less than 6.6 and TDS not greater than 420 ppm). The boundaries of the AoR were determined by calculating pH and TDS in the shallow drinking water aquifer at hypothetical open wells located at increasing distances from the injection wells until no impact to the aquifer was observed. CO_2 or brine leakage at a location beyond the AoR boundary is possible, but the leaked mass is too small to cause pH or TDS to change outside their threshold values.

The Reservoir Reduced-Order Model – Generator (RROM-Gen) was used to create NRAP-IAM-CS model reservoir ROM look-up tables from the 3D reservoir simulations performed with the ECLIPS code (Exploration Consultants Limited (ECL) Implicit Program for Simulation Engineering in a native format).

Reservoir pressures and CO_2 saturations were calculated for the top of Navajo formation at different simulation times including beginning of injection, during injection, at the end of injection, post injection period and at the end of simulation at 100 years for both sites. For each site, thirteen reservoir scenarios were simulated with different permeability, porosity, and anisotropy of formation sampled; and also with varied CO_2 injection rate and duration. The total amount of CO_2 injected are 50 MT for each scenario.

NRAP-IAM-CS (Pawar et al., 2017) utilizes results of reservoir simulations through lookup tables for reservoir pressures and CO_2 saturations to compute CO_2 and brine leak rates through wellbore. Potential leakage wells inside AoR were used in the risk assessment CO_2 and brine leakage calculations.

Reservoir Pressure and CO_2 Saturation

Following figures show reservoir pressure and CO_2 saturation processed by RROM-Gen for one of the reservoir scenarios at Buzzards Bench and Drunkards Wash, respectively. In this scenario (1), reservoir has CO_2 injection rate of 2.5Mt/yr, injection duration 20 years, reservoir permeability17.16 mD, reservoir porosity 12%, and reservoir anisotropy (kz/kx) 0.05 mD/mD.

Figure 36 and Figure 37 show the spatial distribution of scenario 1 reservoir pressures and CO_2 saturations at three different times for Buzzards Bench. These times reflect initial conditions (0 years), after 20 years of injection (20 years), and after an additional 80 years of post-injection monitoring (100 years). The pressure values from these modeling results were used as inputs into the NRAP-IAM-CS to determine the AoR and potential leakage from a hypothetical open wellbore.

NRAP-IAM-CS Model Setup

Buzzards Bench:

• Reservoir top elevation	-331 m (top of the Navajo)
• Hypothetical well	Open well
• USDW	Generic carbonate aquifer geochemistry
• USDW Impact criterion	No impact
• Reservoir Brine Molality	1.9 mole/kg
• USDW hydrologic parameters:	
o Thickness	262 m
o Top elevation	968 m
o Pressure	11.03 MPa
o Temperature	24.6 °C
o Permeability	1.15e-12 m^2
o Porosity	0.2

Drunkards Wash:

• Reservoir top elevation	-240 m (top of the Navajo)
• Hypothetical well	Open well
• USDW	Generic carbonate aquifer geochemistry
• USDW Impact criterion	No impact
• Reservoir Brine Molality	1.9 mole/kg
• USDW hydrologic parameters:	
o Thickness	209 m
o Top elevation	1091 m
o Pressure	9.6 MPa
o Temperature	20.6 °C
o Permeability	1.15e-12 m^2
o Porosity	0.2

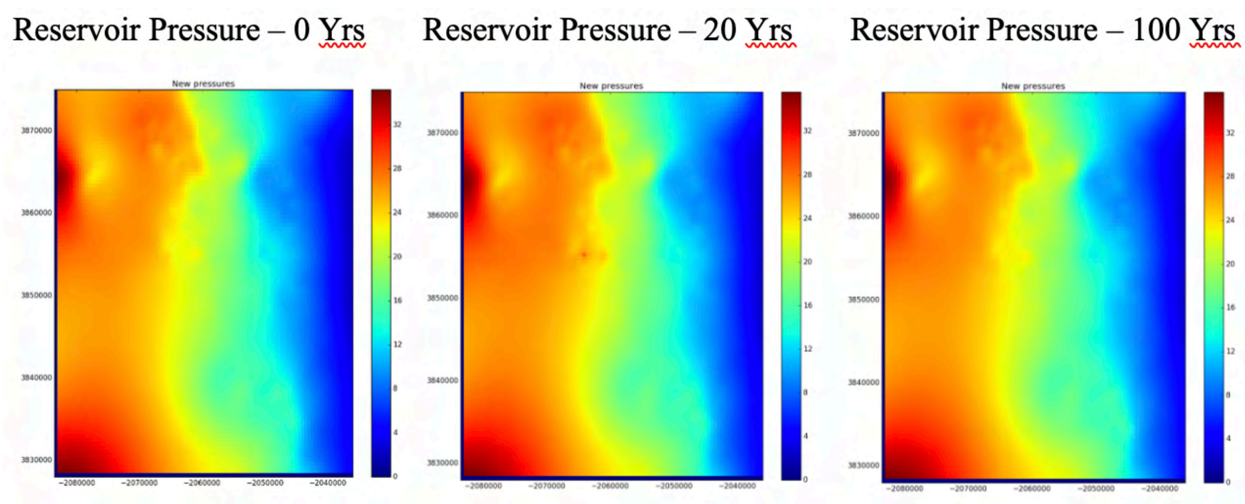

Figure 36. Plots showing predicted pressures in the storage reservoir due to CO_2 injection.

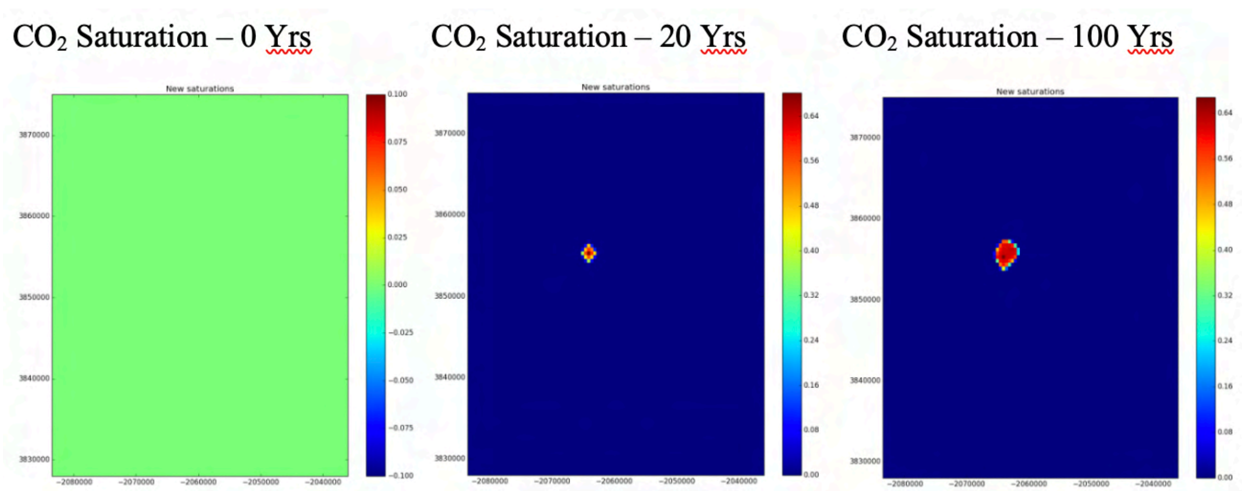

Figure 37. Plots showing predicted CO_2 saturations in the storage reservoir due to CO_2 injection.

Figure 38 and Figure 39 show the spatial distribution of scenario 1 reservoir pressures and CO_2 saturations at three different times for Drunkards Wash.

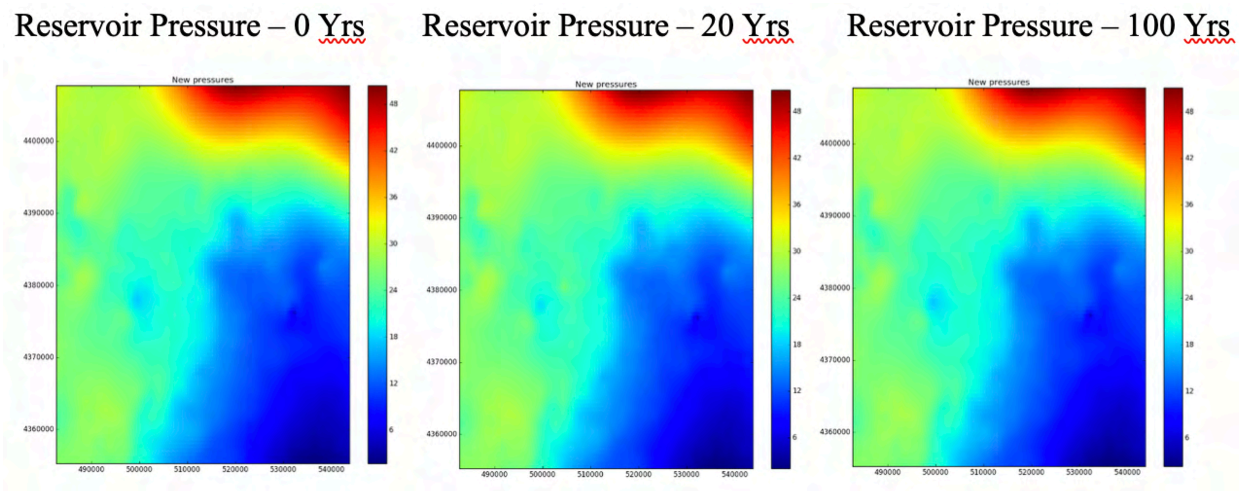

Figure 38. Plots showing predicted pressures in the storage reservoir due to CO_2 injection.

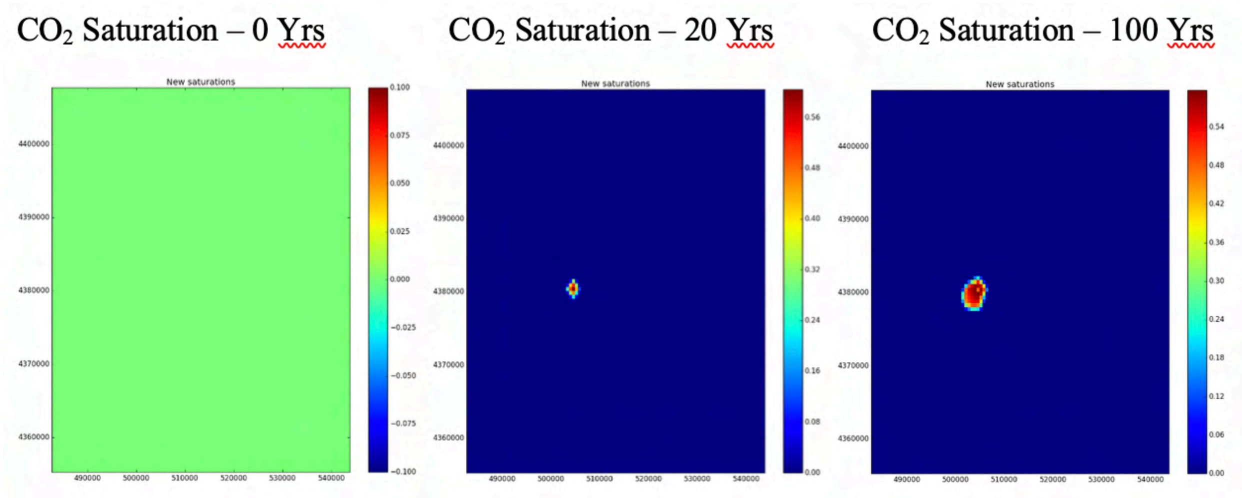

Figure 39. Plots showing predicted CO_2 saturations in the storage reservoir due to CO_2 injection

Risk based Area of Review Delineation Process

Risk-based AoR is determined by the impact to USDW due to wellbore leakage. AoR is defined as an area outside of which there is no impact to USDW due to leakage through a hypothetical open well (i.e. zero plume volumes of TDS > 420 ppm and pH < 6.6).

For risk-based AoR delineation, a hypothetical open well is placed at various locations around the injection well. Multiple different cases were simulated, each representing a distinct spatial location of the hypothetical well. Note that each IAM simulation had only one open well. For both sites, the simulation duration are set to be 100 years.

IAM model sampled over all 13 reservoir scenarios for both sites. Figure 40, Figure 41 and Figure 42 show example of AoR delineation process model results for hypothetical open wells located at a distance of 1, 2 and 3 km from the North of injection well at Drunkards Wash for one of the 30 year injection duration reservoir scenarios.

Figure 40 and Figure 41 demonstrate:

- No CO_2 and brine leakage was found in hypothetical open wellbores located beyond 3 km from the injection well.
- CO_2 and Brine leakage gradually decreases for hypothetical open wellbore located farther away from the injection well.

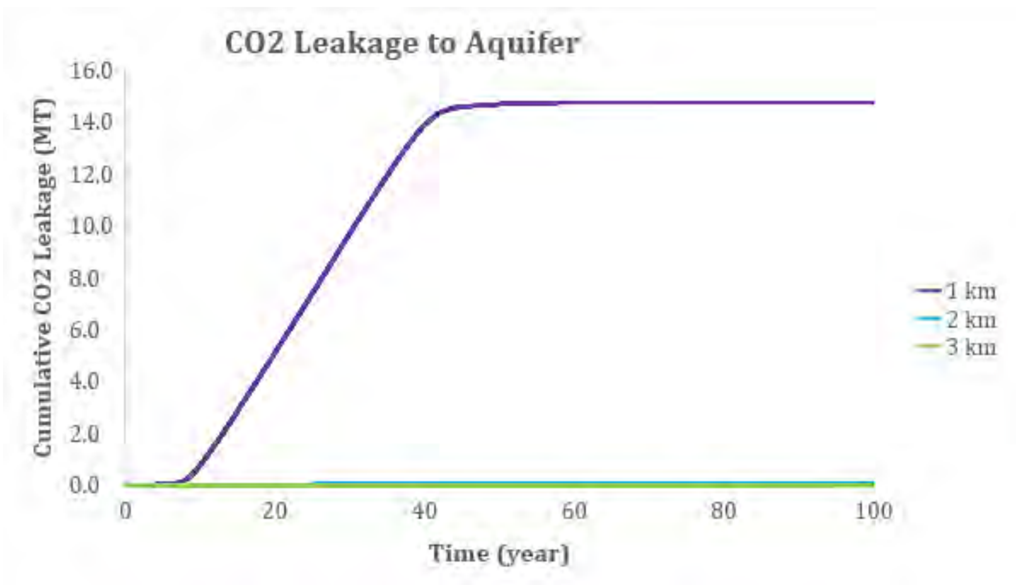

Figure 40. Cumulative CO_2 leakage to groundwater aquifer from wells located at different locations from the injection well.

Figure 41. Cumulative brine leakage to groundwater aquifer from wells located at different locations from the injection well.

Figure 42 and Figure 43 show:

- The reservoir pressure at hypothetical open wellbores located at 1km, 2km and 3km away from the injection well. For this 30 year injection and 70 year of post-injection monitoring scenario, pressure builds over first 30 years and drops off to a common level after about an additional 10 years.
- The CO_2 saturation plume extends 3 km from the injection well.

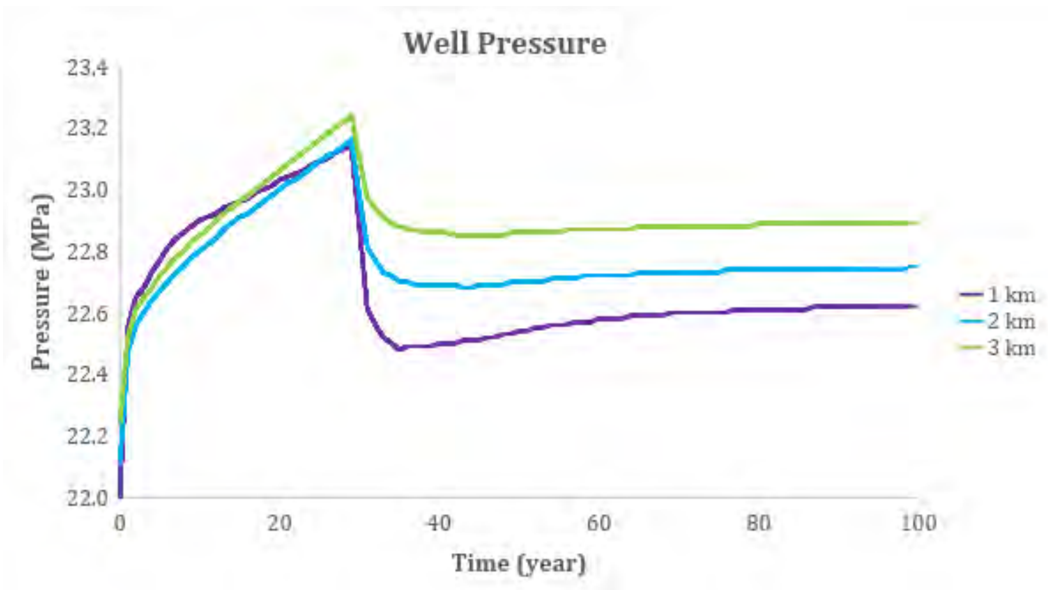

Figure 42. Time-dependent reservoir pressure plots at different well-placement locations.

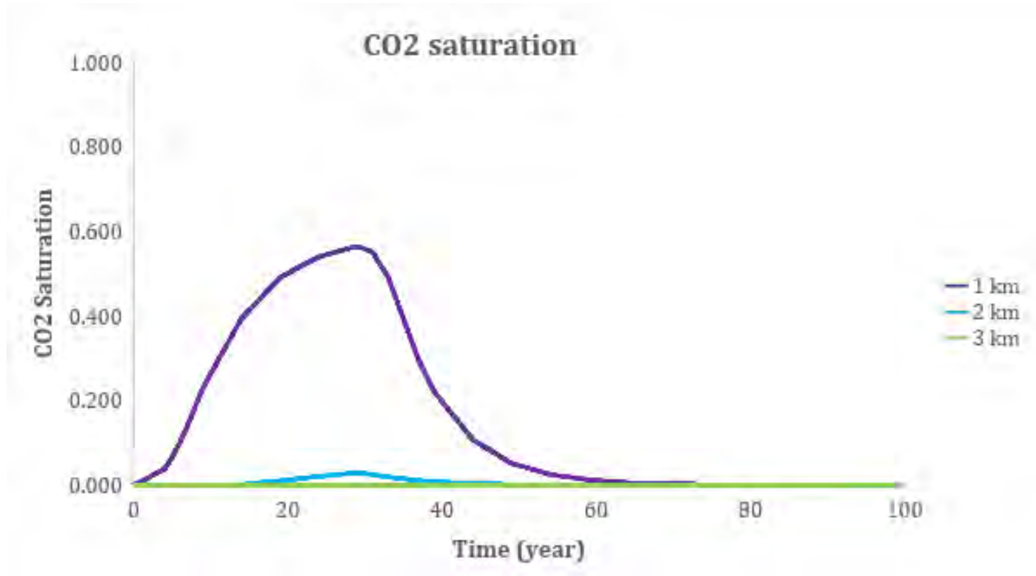

Figure 43. Time-dependent CO_2 saturation plots at different well-placement locations.

Figure 44 and Figure 45 demonstrate that:

- There is no pH and TDS impact due to leakage from hypothetical open wellbores located beyond 3 km from the injection well.
- The time at which the pH and TDS impact starts increases with the distance of hypothetical open wellbore from the injection well.

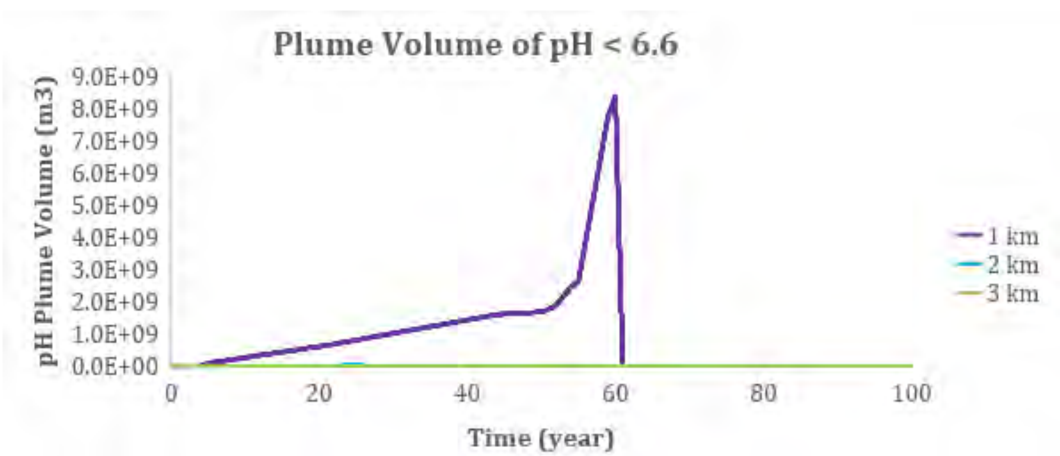

Figure 44. Time-dependent volume of pH < 6.6 plume due to leakage from wells placed at different locations.

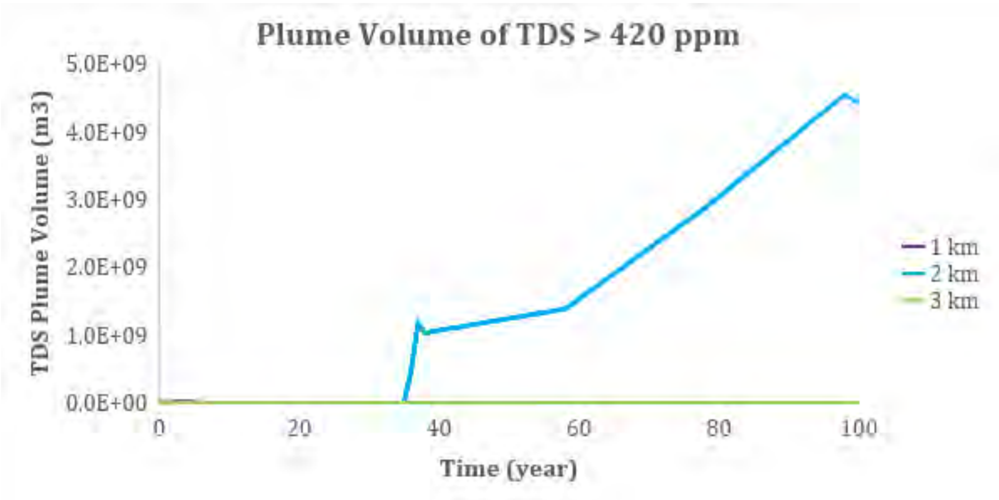

Figure 45. Time-dependent of volume of TDS > 420 ppm plume due to leakage from wells placed at different locations.

Results

Risk-based analysis employing hypothetical wells placed at different locations around the injection well led to delineation of AoR for Buzzards Bench and Drunkards Wash as follows:

The AoR are irregular shaped area surrounding the injection well for both sites. Note that the AoR delineation processed in this study is a conservative estimate, because the criteria used for delineation AoR is that it is an area outside of which there is no impact to USDW due to leakage through a hypothetical open well (i.e. zero plume volumes of TDS > 420 ppm and pH < 6.6) for ANY of the 13 reservoir scenarios. As IAM only identifies models with x- and y-axes that are horizontal and vertical, the Buzzards Bench model had to be rotated by 55.4445 degrees clockwise, during which process the x- and y- coordinates were rotated. Once IAM analysis was completed, the rotated coordinates were back-transformed to the original coordinate system (as shown in Table 17).

Figure 46 and Figure 47 show the AoR shape for Buzzards Bench and Drunkards Wash, respectively. Note that Buzzards Bench site coordinates may need to be rotated as the coordinates for reservoir results were rotated.

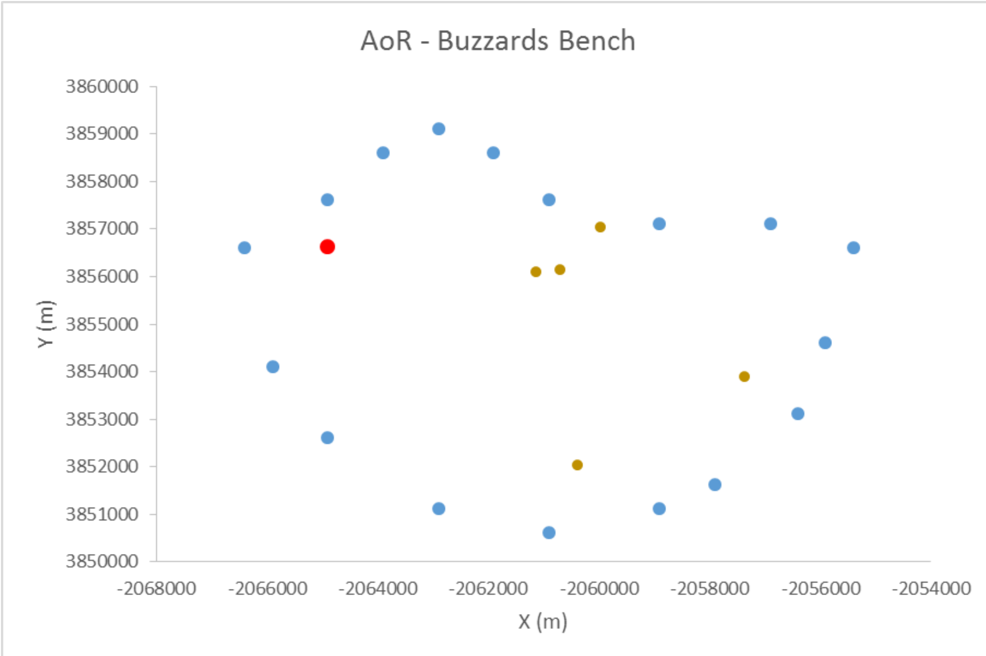

Figure 46. Buzzards Bench site risk-based AoR range shown in blue dots. The Red dot is the injection well location, and the brown dots are the potential leakage wells located inside the AoR.

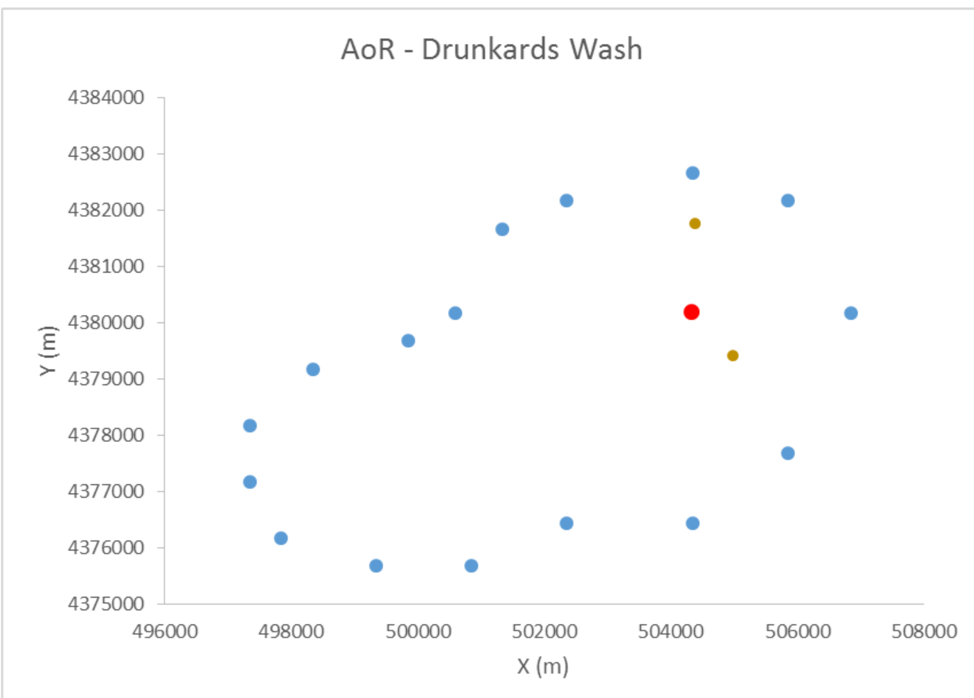

Figure 47. Drunkards Wash site risk-based AoR range shown in blue dots. The Red dot is the injection well location, and the brown dots are the potential leakage wells located inside the AoR.

Table 17 and Table 18 show the AoR boundary points coordinates for the two sites, respectively. Injection well location and inside AoR potential leakage well locations are also included in the tables.

Table 17. Coordinates of injection well, AoR boundary points and potential leakage wells inside AoR for Buzzards Bench.

Well Locations	X-rotated (m)	Y-rotated(m)	X-original (m)	Y-original (m)
Injection Well 1 (IW)	-2064908	3856616	486878	4347445
AoR boundary point Location 1	-2066408	3856616	485643	4348296
AoR boundary point Location 2	-2055408	3856616	494702	4342057
AoR boundary point Location 3	-2064908	3857616	487445	4348269
AoR boundary point Location 4	-2064908	3852616	484609	4344151
AoR boundary point Location 5	-2056408	3853116	491893	4339742
AoR boundary point Location 6	-2060908	3850616	486769	4340235
AoR boundary point Location 7	-2060908	3857616	490740	4346000
AoR boundary point Location 8	-2058908	3857116	492103	4344454
AoR boundary point Location 9	-2058908	3851116	488700	4339513
AoR boundary point Location 10	-2062908	3851116	485406	4341781
AoR boundary point Location 11	-2062908	3859116	489943	4348370
AoR boundary point Location 12	2056908	3857116	493750	4343320
AoR boundary point Location 13	-2057908	3851616	489807	4339357
AoR boundary point Location 14	-2065908	3854116	484636	4345954
AoR boundary point Location 15	-2055908	3854616	493156	4340693
AoR boundary point Location 16	-2063908	3858616	488836	4348525
AoR boundary point Location 17	-2061908	3858616	490483	4347391
Inside AoR potential leakage well location 1	-2060374	3852025	488008	4341093
Inside AoR potential leakage well location 2	-2061131	3856092	489691	4344872
Inside AoR potential leakage well location 3	-2057356	3853877	491544	4340906
Inside AoR potential leakage well location 4	-2060697	3856134	490073	4344660
Inside AoR potential leakage well location 5	-2059968	3857032	491182	4344986

Table 18. Coordinates of injection well, AoR boundary points and potential leakage wells inside AoR for Drunkards Wash.

Well Locations	X (m)	Y(m)
Injection Well 1 (IW)	504347	4380173
AoR boundary point Location 1	504347	4382673
AoR boundary point Location 2	504347	4376423
AoR boundary point Location 3	506847	4380173
AoR boundary point Location 4	500597	4380173
AoR boundary point Location 5	502347	4376423
AoR boundary point Location 6	502347	4382173
AoR boundary point Location 7	505847	4382137
AoR boundary point Location 8	505847	4377673
AoR boundary point Location 9	500847	4375673
AoR boundary point Location 10	499347	4375673
AoR boundary point Location 11	497347	4378173
AoR boundary point Location 12	498347	4379173
AoR boundary point Location 13	497847	4376173
AoR boundary point Location 14	497347	4377173
AoR boundary point Location 15	501347	4381673
AoR boundary point Location 16	499847	4379673
Inside AoR potential leakage well location 1	504401	4381752
Inside AoR potential leakage well location 2	504984	4379410

Figure 48, Figure 49, Figure 50 and Figure 51 show the CO_2 and brine leakages from the potential leakage wells inside the AoR for all 13 reservoir scenarios for Buzzards Bench and Drunkards Wash, respectively. The leakage calculations are carried out assuming all these wells with cement permeability of 5×10^{-11} m^2

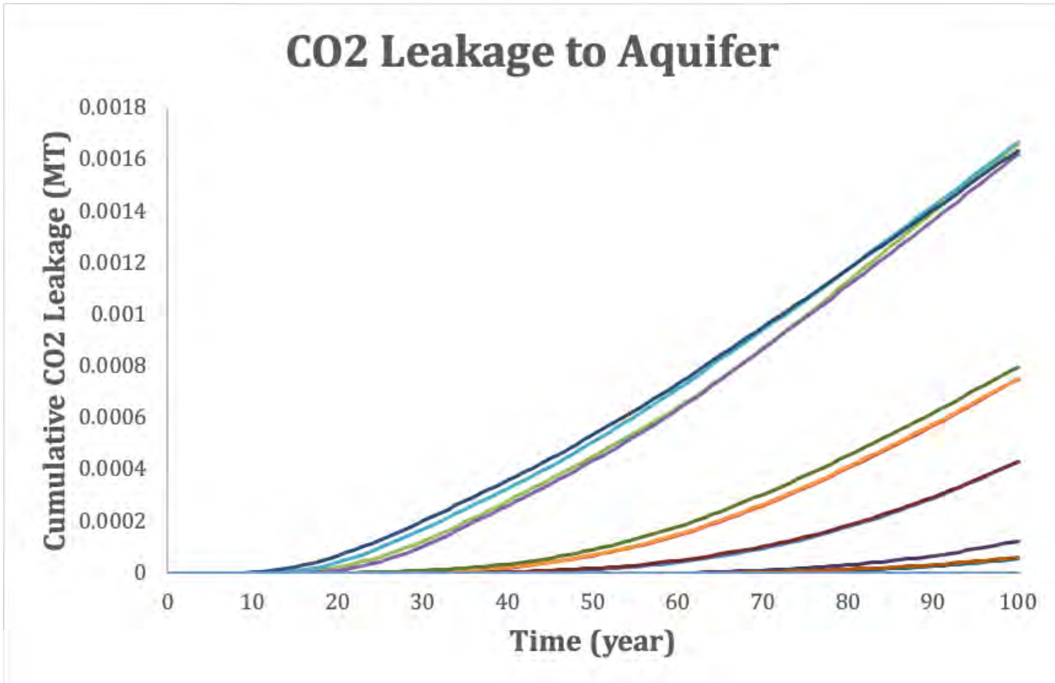

Figure 48. Cumulative CO_2 leakage to groundwater aquifer from potential leakage wells inside AoR for Buzzards Bench.

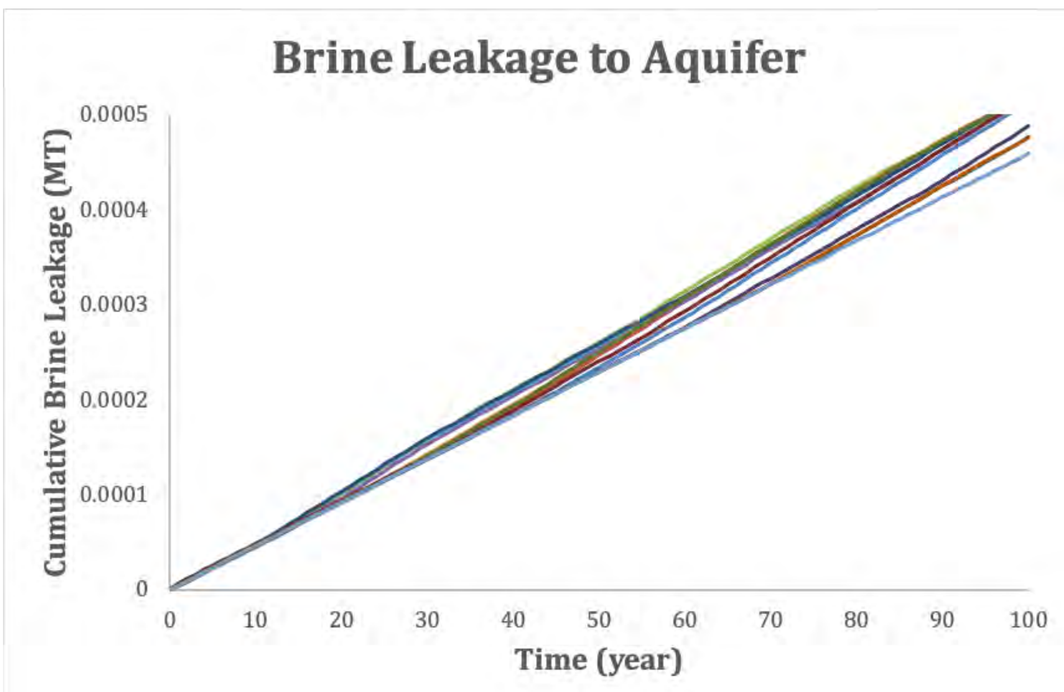

Figure 49. Cumulative brine leakage to groundwater aquifer from potential leakage wells inside AoR for Buzzards Bench.

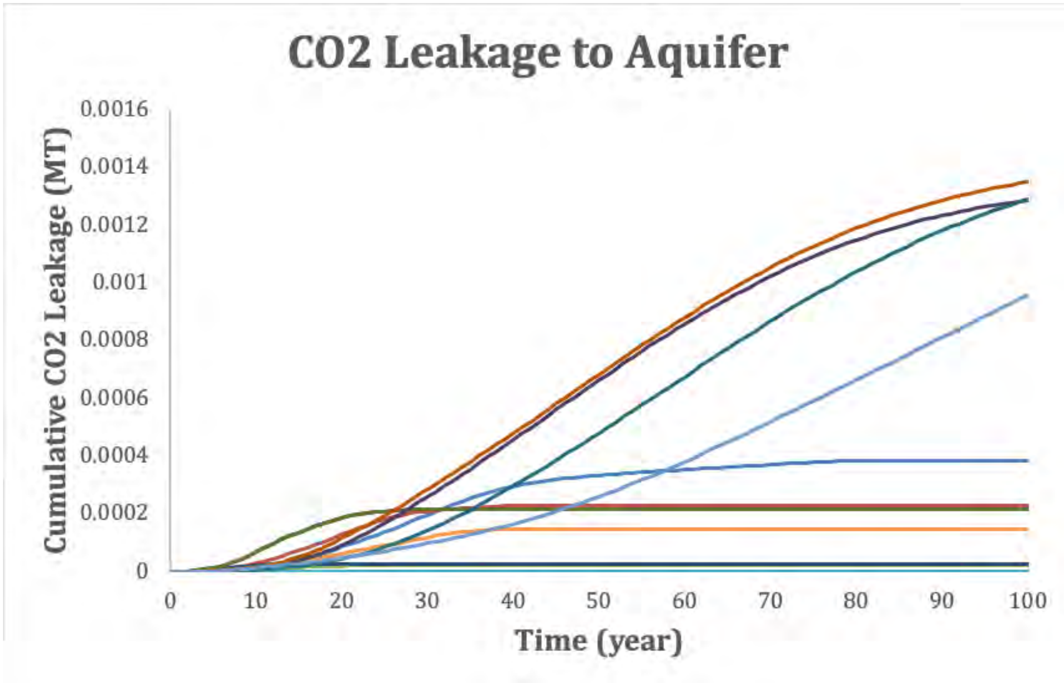

Figure 50. Cumulative CO_2 leakage to groundwater aquifer from potential leakage wells inside AoR for Drunkards Wash.

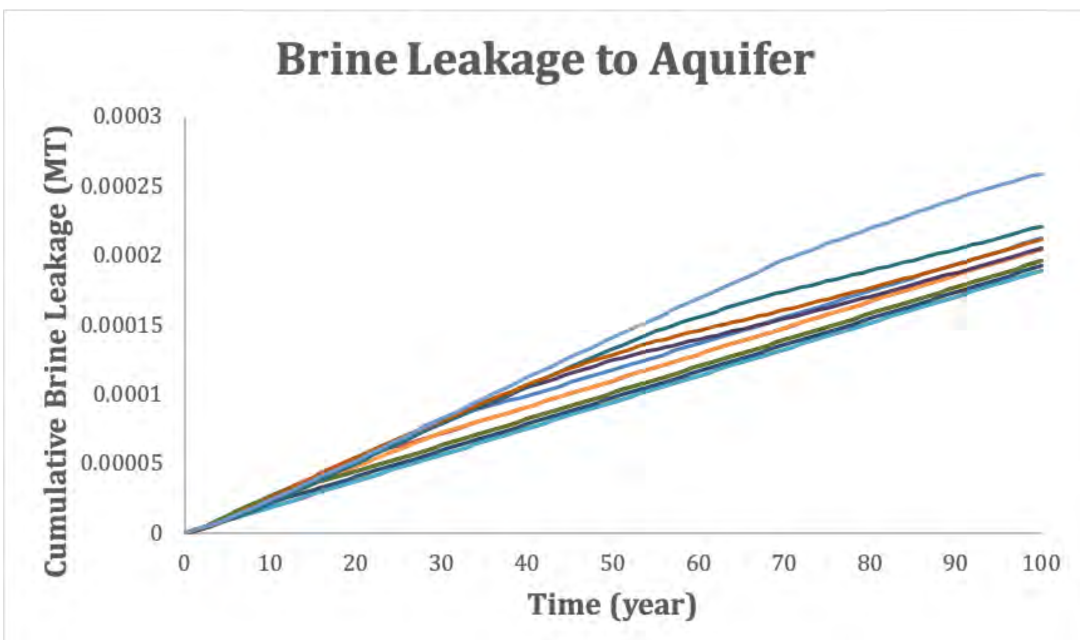

Figure 51. Cumulative brine leakage to groundwater aquifer from potential leakage wells inside AoR for Drunkards Wash.

3.4 RISK ASSESSMENT AND MITIGATION

3.4.1 Qualitative Risk Assessment

Catalog of Project Challenges

At an early stage of the project (Q2 2017), the project team has identified Catalog of Project Challenges for this Risk Assessment and Mitigation subtask:

(1). Scarcity of data. Similar to other saline storage projects, the project suffers from lack of data in the target saline formation due to the lack of interest in the past. This might cause significant uncertainty in the feasibility study. Assessment of storage capacity, injectivity, and containment should account for this uncertainty.

(2). Geologic feature (target formation cropping out). Due to the regional geologic structure, proposed target formations are cropping out around San Rafael Swell. If the CO_2 continuously migrates through up-dip direction due to the buoyant force, it would undergo phase change and reach the surface. This should be well understood during the feasibility study and be considered for MVA plan.

Risk Registry

The project team has worked on conducting a Failure Mode and Effects Analysis (FMEA) with information gathered under other subtasks. A type of FMEA has been used for analysis of specific operational (programmatic) risk. This is a procedure in development and operations management for analysis of potential failure modes within a system for classification by the severity and likelihood of the failures. A successful FMEA activity helps a team to identify potential failure modes based on past experience with similar products or processes, enabling the team to design minimal effect of those failures out of the system with the minimum effort and resource expenditure is widely used in industries in various phases of the life cycle of a process. Failure modes are any errors or defects in a process, design, or item. Effects analysis refers to studying the consequences of those failures.

FMEA can provide an analytical approach, when dealing with potential failure modes and their associated causes. When considering possible failures – like safety, cost, performance, scheduling, reliability, and personnel changes – a manager can get a lot of information about how to alter the process, in order to avoid or minimize the adverse effects of these events. FMEA provides a tool to determine which risk has the greatest concern, and therefore an action is needed to prevent, minimize, or provide alternate options for a problem before it arises. The development of these specifications will increase probability of a successful project. The risk priority number, which is the product of occurrence, severity, and detection, will provide a gauge of relative importance.

The project team assembled a risk registry for the Primary (Buzzards Bench) and Secondary (Drunkards Wash) Site options, which summarize potential risks for all major activities of a commercial-scale CCS project.

A total number of 404 risk features/events/processes (FEPs) are listed in the risk registry. It includes 23 main aspects of risk categories, including programmatic/operational risks as well as sequestration/technical risks. We continuously updated the risk registry, including relative ranking of project risks; risk categorization by cause and potential impacts; identify risks that require near-term vs. long-term responses, and identify risks that require more investigation.

The FEPs were evaluated based on site-specific information via Failure Modes and Effects Analysis (FMEA). In particular, potential failure mode, cause of failure, potential failure effect, method of detecting failure early, and risk prevention steps/risk mitigation steps are defined for each FEP. The project team assessed failure probability (P), failure severity (S), and difficulty of failure detection (D) on a scale of 1~5, with lower values suggesting lower failure probability, lower failure severity, and easier failure detection. As this project is focused on pre-feasibility study, many FEPs are not applicable (e.g., site construction and operation); therefore, zero values were assigned to those FEPs. Risk priority number was calculated as the product of the P, S, and D. All FEPs were sorted by risk priority numbers. Due to the cost of CO_2 capture facilities, FEPs associated with CO_2 sources exhibit high risk priority numbers.

Please refer to the Appendix J for the full Risk Registry.

3.4.2 Quantitative Risk Assessment

Uncertainty analysis of AoR

For each proposed storage site, a set of 13 Eclipse simulations were used to develop reduced order models (ROMs) for calculating area that has overpressure greater than 5 bar and 10 bar, respectively. The same set of simulation results were also used by NRAP-IAM-CS tool to generate risk-based AoR. Accuracy of ROMs are measured by R2 between results from ROMs and overpressure area based on Eclipse simulation results, as shown in Table 19. During injection period (up to 30 years to 2048), predictions from ROMs are very close to Eclipse simulation results with most of R2 values greater than 0.95. During monitoring period, most ROMs hold acceptable accuracy with a few exceptions where there were no ROMs developed as not enough training data were provided.

Table 19. R2 between results from ROMs and Eclipse simulations (N/A indicates not enough data to generate ROMs, therefore R2 values are missing).

Case/Year	2023	2028	2038	2048	2068	2098	2118
5 bar @ Buzzards Bench	0.996	0.989	0.786	0.991	0.974	0.955	0.961
5 bar @ Drunkards Wash	0.985	0.983	0.959	0.903	N/A	0.704	0.697
10 bar @ Buzzards Bench	0.964	0.987	0.875	0.957	0.849	N/A	N/A
10 bar @ Drunkards Wash	0.956	0.942	0.969	0.779	0.917	0.848	0.866

The validated ROMs were employed to predict overpressure areas at both proposed sites with 500 realizations, parameters of which were randomly generated from the uncertainty range shown in **Error! Reference source not found.**. Figure 52 and Figure 53 show area with 5 bar overpressure at Buzzards Bench and Drunkards Wash sites, respectively. The risk-based AoR predicted by NRAP-IAM-CS tool is presented in black lines for both sites (63.44 km2 for Buzzards Bench and 44.45 km2 for Drunkards Wash). It is shown that uncertain range of 5-bar overpressure area increases with time at both sites. The 5-bar overpressure area at year 2023 (i.e., 5 years of injection) has the least deviation from the risk-based AoR prediction by NRAP-IAM-CS (black vertical lines). The 10-bar overpressure areas at two sites are shown in Figure 54 and Figure 55. The risk-based AoR predictions fall in the uncertain range of 10-bar overpressure areas forecasted by ROMs. The comparison between overpressure area and risk-based AoR implies that NRAP-IAM-CS tool was able to predict a reasonable AoR with limited data (i.e., 13 simulation results versus 500 realizations in this case).

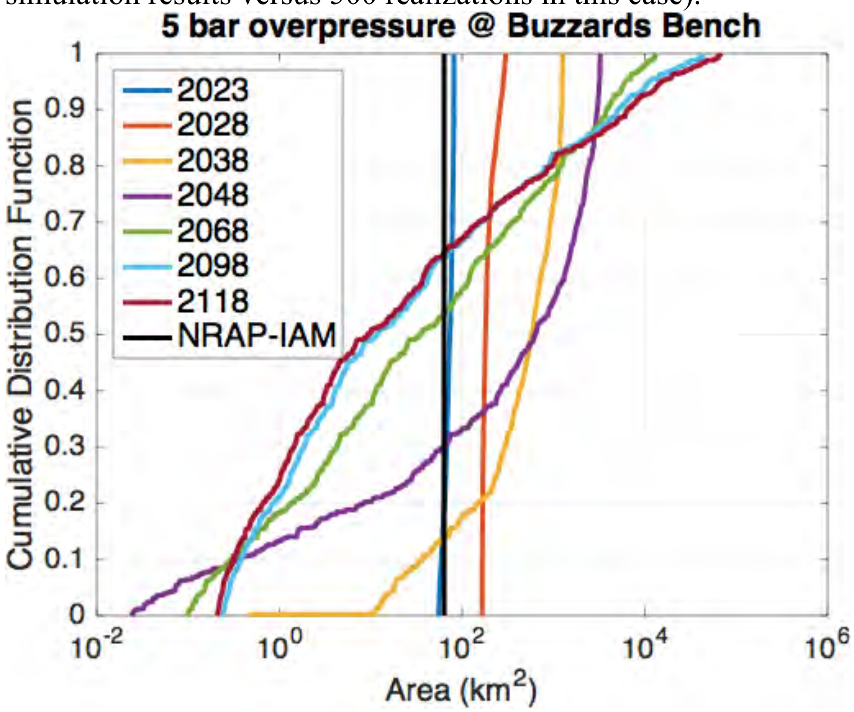

Figure 52. Cumulative distribution function of 5-bar overpressure area at Buzzards Bench.

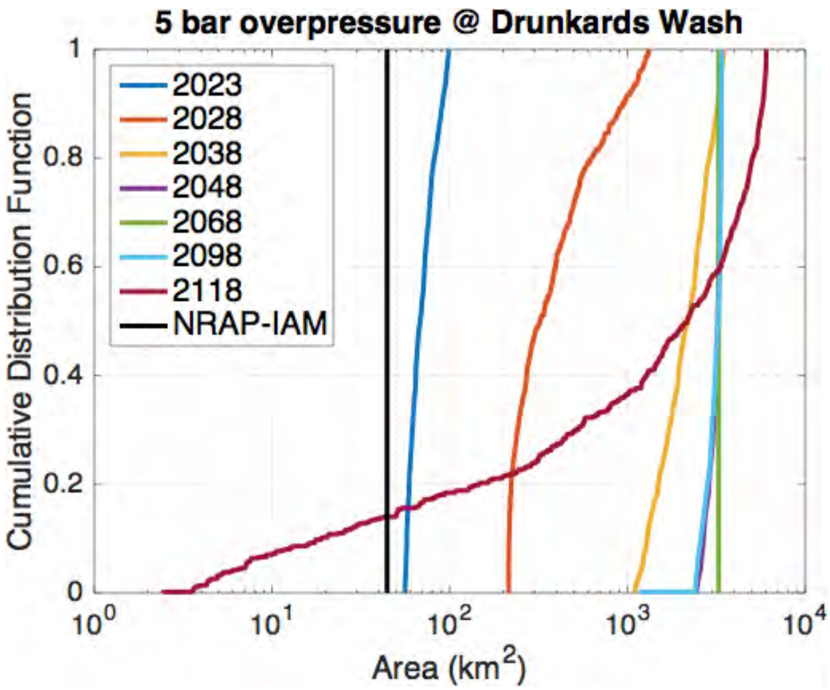

Figure 53. Cumulative distribution function of 5-bar overpressure area at Drunkards Wash (ROMs at 2068 are missing, an average of Eclipse simulation results was used to calculate the area, green line).

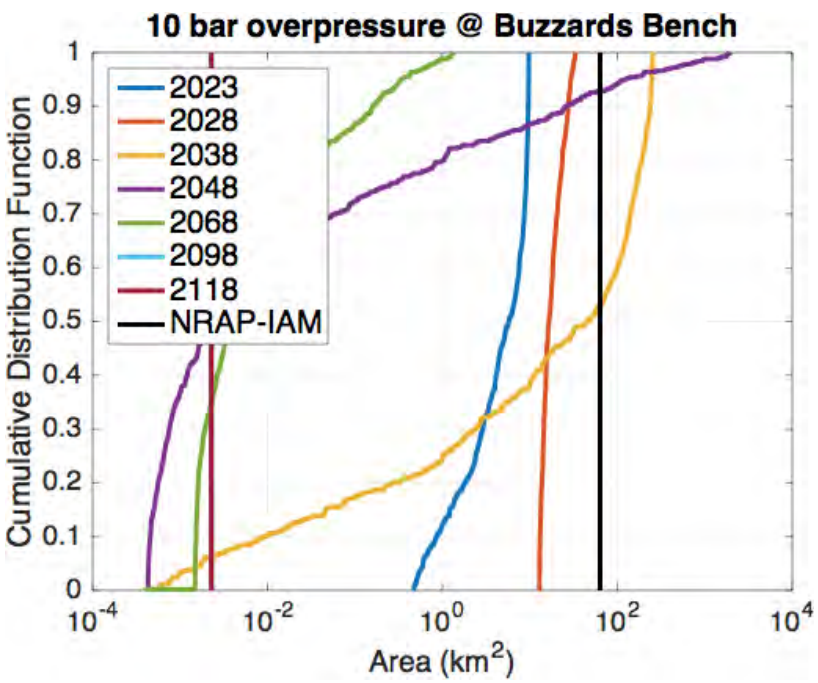

Figure 54. Cumulative distribution function of 10-bar overpressure area at Buzzards Bench (ROMs at 2098 and 2118 are missing, average of Eclipse simulation results were used to calculate the area, light blue and dark red lines).

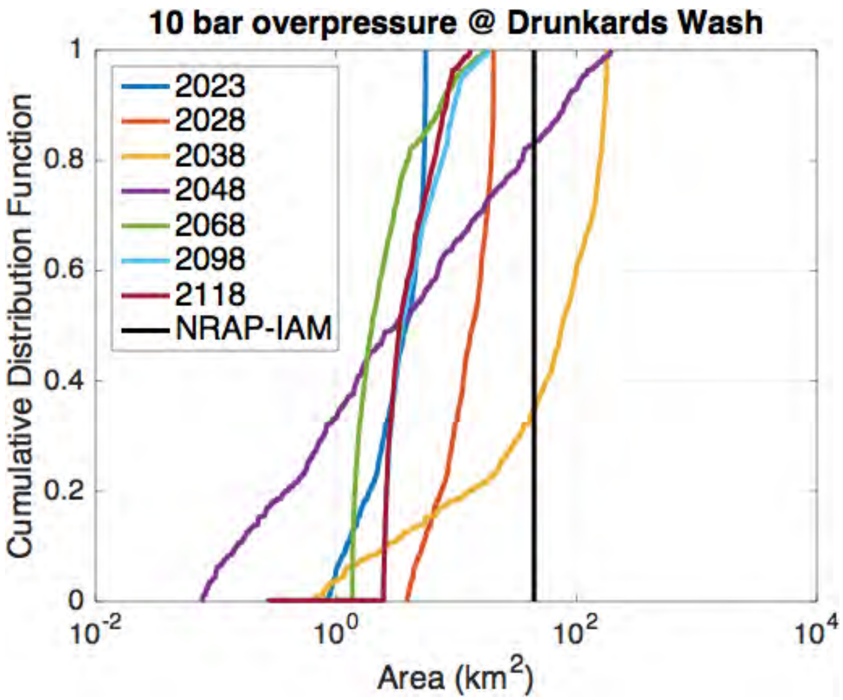

Figure 55. Cumulative distribution function of 10-bar overpressure area at Drunkards Wash.

CO_2 Storage Capacity Analysis

Successful implementation of geological carbon dioxide (CO_2 sequestration (GCS) projects requires long-term storage capacity and security (Celia et al., 2015; IPCC, 2005). Quantitative assessment of CO_2-water-rock interactions and potential changes to geological properties that might affect storage capacity and seal reliability are required by the United States Environmental Protection Agency (U.S. EPA) prior to a CO_2 storage permit being granted (EPA, 2013).

To date, forecasting long-term CO_2 migration and evaluation of storage capacity and security in deep saline reservoirs largely relies on modeling and numerical simulations with site-specific geological data (Jiang, 2011). However, quantitative analyses of trapping mechanisms and/or storage efficiency over time with special impacts, especially for commercial-scale (> 50 MT) storage, are limited in number. Therefore, a primary goal of this task was to quantify potential temporal and spatial impacts on CO_2 migration, CO_2-water-rock interactions, potential changes of storage capacity due to mineral alteration, and leakage risks of the Navajo Sandstone in the potential storage site at Buzzard's Bench with reactive transport simulations. To overcome an obstacle of limited data prior to a detail site characterization, different scenarios with different ranges of parameters were conducted. Specific objectives of this study include: (1) to evaluate long-term (1,000 years) storage capacity and security of the Navajo Sandstone; (2) to quantify trapping mechanisms and storage efficiency through time and space; (3) to quantify the potential changes of storage capacity due to mineral alteration and porosity changes; and (4) to evaluate CO_2 migration and sealing reliability of the overlying caprock.

Results suggest that the Navajo formation may be a reliable CO_2 sequestration reservoir, capable of trapping commercial volumes. The Jurassic Kayenta and Wingate formations may also store some injected CO_2, with these and other clastic formations forming a "stacked storage" system.

Storage efficiency decreases with distance away from an injection well, and the estimated storage efficiency for the case study simulations (Navajo storage only) are 2.3 ± 1% within the area of review (AoR) calculated by National Risk Assessment Partnership (NRAP) toolset. After 1000 years, about half of the injected CO_2 may be sequestered in safe phases including residually-trapped CO_2 via surface tension, aqueous and mineral phases. A small amount of total injected CO_2 (~3%) tends to migrate into the caprock, but is mostly stored in the sandstone reservoir. Simulated porosity enhancement caused by mineral alteration is negligible within 1000 years of the start of injection, with only ~0.6% added to the total pore volume by the end of simulations. Future studies of detailed reservoir and caprock characteristics with in-situ samples may be helpful for further determining reservoir sequestration capacity and reliability.

Additional information on the CO_2 storage capacity of the Buzzard's Bench site can be found in (Xiao et al., 2019).

3.4.3 NRAP Screening and Application

The project team has identified two NRAP tools that may be applicable to this project. These tools are the NRAP-IAM-CS (Integrated Assessment Model for Carbon Storage) tool, and the RROM-GEN (Reservoir Reduced Order Model Generator) tool.

Particularly, the WLAT and AIM tool are integrated in the NRAP-IAM-CS tool. The project team has downloaded the installer and installed the tool on the main workstation. However, while running sample problems, unexpected errors occurred and terminated the simulation. The project team scheduled multiple WebEx meetings with developers of this tool, who are also collaborators of the project. The diagnosis process is still ongoing.

The project team was able to successfully run the NRAP-IAM-CS tool on a different personal computer. In April of 2018, an outreach of NRAP tools was conducted at the University of Utah, with participants from the College of Engineering at the University of Utah and from the China University of Petroleum (Beijing). A comprehensive introduction about NRAP and its current toolset were presented, followed by a workshop of installation and using the NRAP-IAM-CS tool. Simple scenarios of CO_2 storage were designed to help participants understand how injection volume and model properties (e.g., porosity and permeability) affect potential CO_2 leakage rates. Impacts of numbers and locations of legacy wells were also assessed.

The other evaluated NRAP tool was the RROM-GEN tool. The project team initially planned to use RROM-GEN to generate ROMs based on numerical simulation results for predicting CO_2 plume migration and quantifying associated uncertainty. The project team had an in-depth discussion with the developer of RROM-GEN regarding to theory and algorithms used in this tool. However, it was found that such feature is not included in the current version of RROM-GEN. Therefore, the initial working plan may have to be revised.

The project team has identified two applicable NRAP tools to this project, the NRAP-IAM-CS (Integrated Assessment Model for Carbon Storage) tool, and the RROM-GEN (Reservoir Reduced Order Model Generator). Team members at the University of Utah (UU) and LANL have discussed the approach to use these tools via email communication, teleconference, and in-person meetings. Particularly, UU will conduct reservoir simulations with reservoir simulation package, and apply the RROM-GEN tool to generate look-up tables; these results will be transferred to LANL for following analysis with the NRAP-IAM-CS tool. In addition, LANL will also need information on the top of storage formation, (depth, top, thickness) of regional aquifer, and information on wells (location, depth, vintage, status and other information that can be used to determine the potential integrity) that will be present in the area around the injection wells.

In order to conduct the NRAP-IAM-CS analysis, the project team have assembled information of storage complex (formation tops and thickness) and existing wells (location, depth, and perforation).

The project team also processed the Eclipse simulation results of the 26 realizations. A special version of the RROM-GEN (Reservoir Reduced Order Model Generator) was received from the developer at NETL to analyze the simulation results and create input files for NRAP-IAM-CS tool. Pressure and CO_2 saturation at the top of the storage formation (Navajo) were analyzed at 31 selected time steps, including the initial time step, every year for the first 10 years of injection period, every 5 years for the rest of the injection period, every other year for the first 10 years of post-injection period, and every 5 years for the rest of the 100-year simulation period.

Figure 56 to Figure 59 present selected pressure and CO_2 saturation distribution in the top of the Navajo formation at the end of simulation for both injection sites. Results for all realizations and 31 time steps were evaluated.

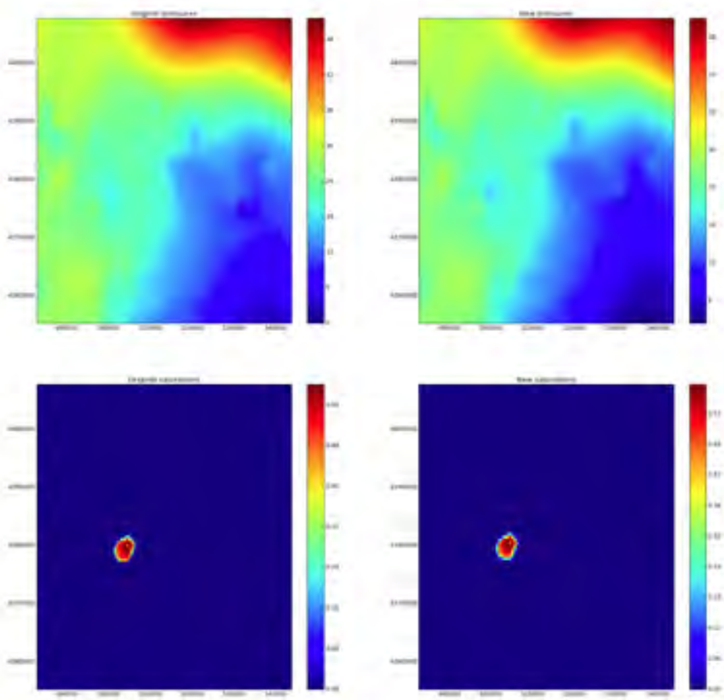

Figure 56. Pressure and CO2 saturation distribution in the top of Navajo at the end of 100-year simulation of Realization #1 at the Drunkards Wash injection site

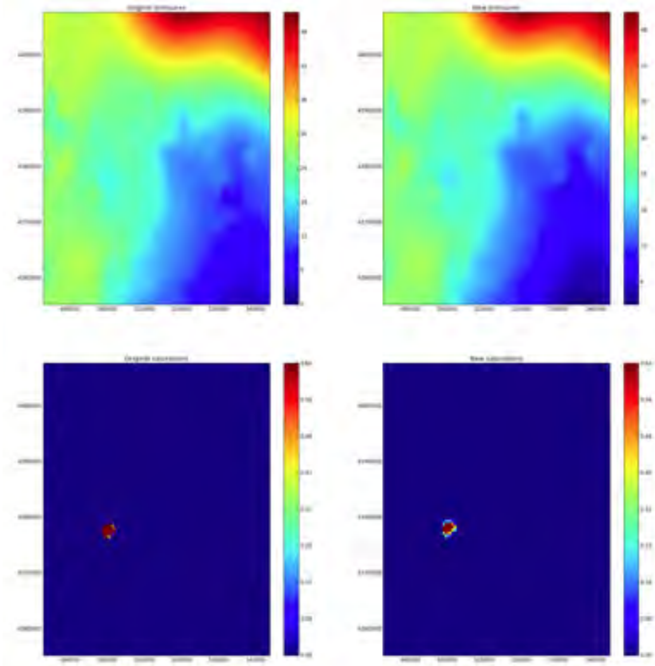

Figure 57. Pressure and CO2 saturation distribution in the top of Navajo at the end of 100-year simulation of Realization #13 at the Drunkards Wash injection site.

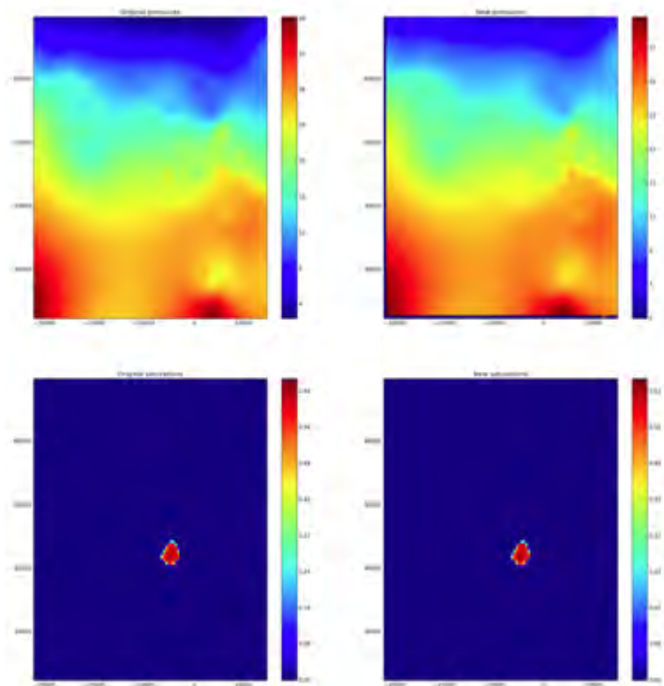

Figure 58. Pressure and CO2 saturation distribution in the top of Navajo at the end of 100-year simulation of Realization #1 at the Buzzard Bench injection site.

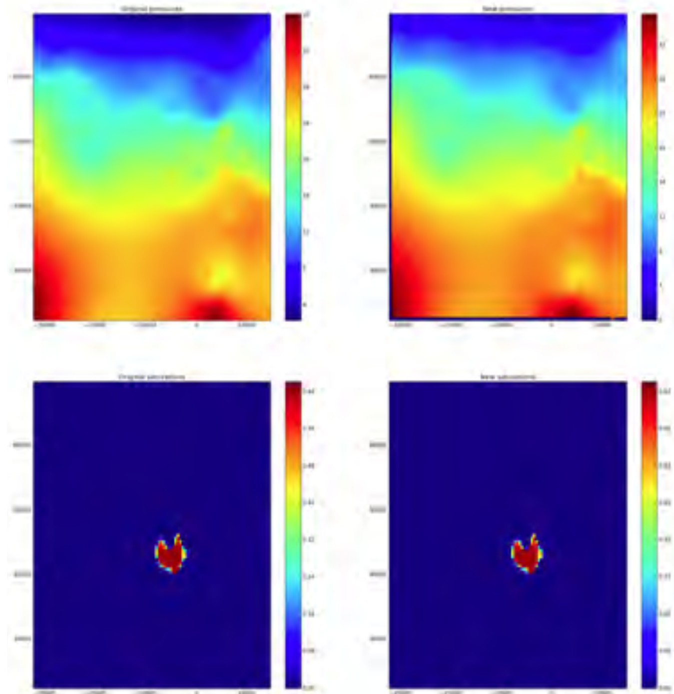

Figure 59. Pressure and CO2 saturation distribution in the top of Navajo at the end of 100-year simulation of Realization #31 at the Buzzard Bench injection site.

3.4.4 Comments and Feedback on Using NRAP Tools

The NRAP tools used for this project were able to deliver expected outcomes in general. For example, results from the NRAP-IAM-CS tool provide a risk-based Area of Review for the two potential storage sites. The tools were easy to learn. The overall process of using the tools was relatively easy, because of the availability of many built-in options and the simplification of the NRAP tools made to the original physics-based models. However, the project team hope the tools could be even more helpful by enhancing capability and flexibility:

(1) Format compatibility. The project team identified that RROM-GEN has restricted capability of reading simulation results. In particular, the grid has to have the same number of cells in each column (or each row). Otherwise, the grid is not compatible with the current version of RROM-GEN. This is usually not an issue for simplified models; however, models representing complex geological settings will cause errors using RROM-GEN. We hope this could be improved in the next version of RROM-GEN.

(2) Plotting styles. Both RROM-GEN and NRAP-IAM-CS provide visualization outputs, including line graphs and 2-D slices. While these plots are helpful for quick understanding simulation data, the plotting quality could be substantially improved. We hope the tools would allow users to customize the plotting styles, including font style and size, line color and width, axis title and labels, and legends.

(3) Reduced Order Model and Export options. The NRAP-IAM-CS tool uses output from RROM-GEN as look-up tables for uncertainty analysis. It would be more helpful if the RROM-GEN tool could provide more types of reduced order models other than the look-up table, such as linear or polynomial regression models. In addition, we would also like

to have an export option in these NRAP tools to export the reduced order model they use for leakage risk analysis. The exported files could be coupled with external software packages for either comparison study or further analysis.

4.0 Non-Technical Challenges

Prior analyses have identified a wide variety of legal, regulatory, and other hurdles that Carbon Capture and Sequestration (CCS) projects may face. Many of these studies suggest that what limits CCS deployment is not always legal or regulatory in nature. Several early studies, for instance, suggested that the lack of commercial-scale CCS demonstration projects act as a key constraint on societal appetite for CCS generators.[1] However, subsequent research revealed that technology demonstration tends not to be the key impediment to commercial-scale CCS development. Rather, a 2013 survey of more than 200 experts[2] in the United States revealed that there are four key barriers to CCS commercialization:

(1) cost and cost recovery;

(2) the lack of price signal or financial incentive for using CCS;

(3) liability risks; and

(4) an overall lack of comprehensive CCS regulation.[3]

The 2013 study provided important context to the legal, regulatory, and social barriers that, at a broad scale, CCS projects face. Specifically, it showed that, above all else, the cost of CCS—including the energy penalty that CCS imposes on electricity generation as well as public resistance to higher energy prices—is the greatest impediment facing commercial-scale CCS deployment. Following cost, the experts surveyed in the 2013 study suggested that the lack of any clear price signal or other financial incentive for CCS use, such as a carbon tax or greenhouse gas cap-and-trade system, is the second most significant barrier to CCS commercialization. Following cost and the lack of a price signal, those respondents found the

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[1] *See generally, e.g.*, CARNEGIE-MELLON UNIV., DEPARTMENT OF ENGINEERING AND PUBLIC POLICY, CARBON CAPTURE AND SEQUESTRATION: FRAMING THE ISSUES FOR REGULATION, AN INTERIM REPORT FROM THE CCSREG PROJECT (2009); PETER FOLGER, CONG. RESEARCH SERV., CARBON CAPTURE AND SEQUESTRATION (CCS) (2009); GOV'T ACCOUNTABILITY OFFICE, REPORT TO THE CHAIRMAN OF THE SELECT COMMITTEE ON ENERGY INDEPENDENCE AND GLOBAL WARMING, HOUSE OF REPRESENTATIVES: FEDERAL ACTIONS WILL GREATLY AFFECT THE VIABILITY OF CARBON CAPTURE AND STORAGE AS A KEY MITIGATION OPTION (2008); INT'L ENERGY AGENCY, CARBON CAPTURE AND STORAGE: PROGRESS AND NEXT STEPS (2010); LARRY PARKER ET AL., CONG. RESEARCH SERV. CAPTURING CO_2 FROM COAL-FIRED POWER PLANTS: CHALLENGES FOR A COMPREHENSIVE STRATEGY (2009); WORLD RESOURCES INST., OPPORTUNITIES AND CHALLENGES FOR CCS (2007).

[2] These experts consisted of with experience as CO_2 emitters, CCS operators, consultants, regulators, researchers, and nonprofit organizations relevant to CCS.

[3] Lincoln L. Davies et al., *Understanding Barriers to Commercial-Scale Carbon Capture and Sequestration in the United States: An Empirical Assessment*, 59 ENERGY POL'Y 745, 749 (2013).

most significant barrier to CCS to be liability risks associated with CO_2 storage, followed by the lack of an overall CCS regulatory framework.[4]

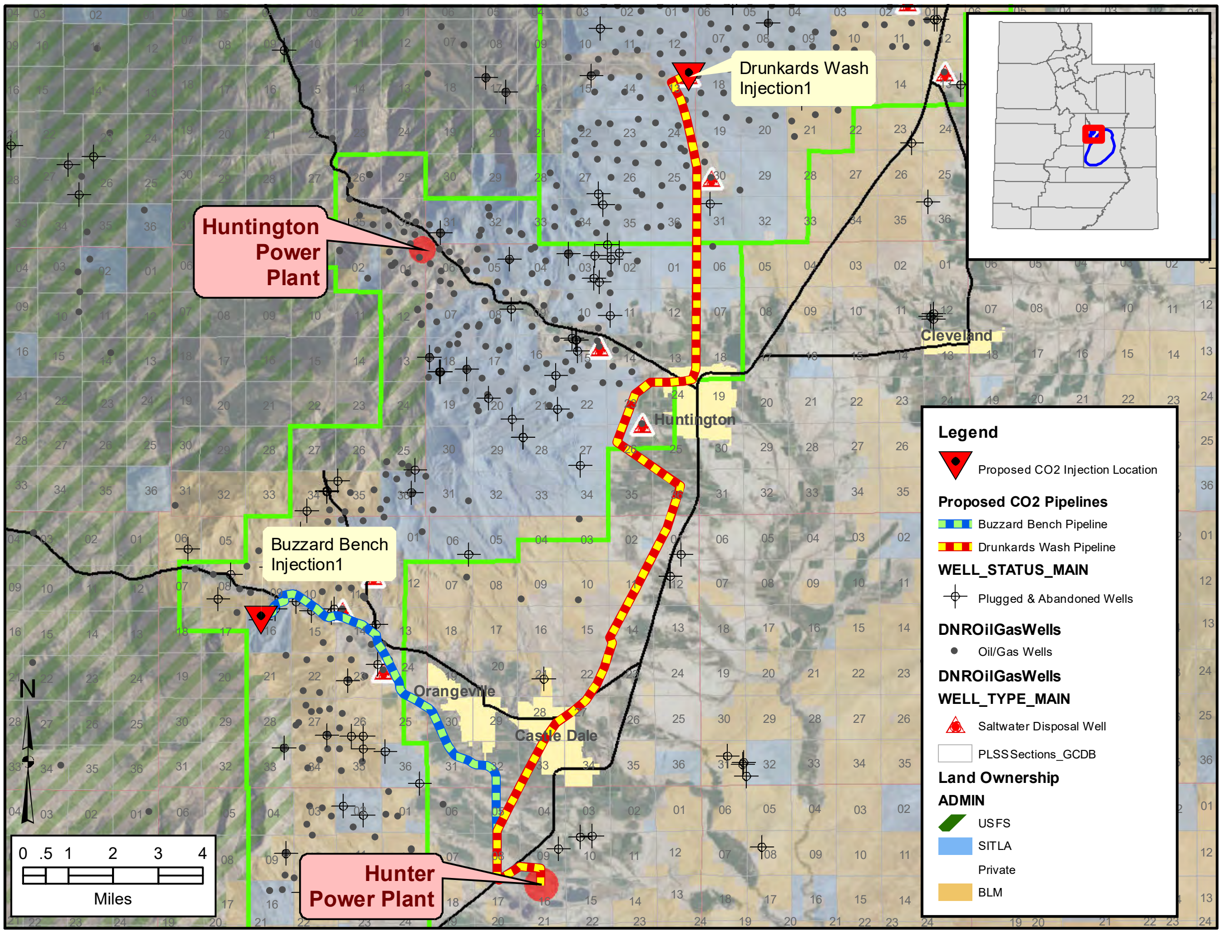

Figure 60. CarbonSAFE Rocky Mountain Location Map.

This project and report seek to identify the legal and regulatory structure that will govern development of any commercial-scale CCS project, including potential gaps in the legal and regulatory scheme. It does so in the context of the potential CarbonSAFE Rocky Mountain project, which would capture CO_2 from Rocky Mountain Power's Hunter or Huntington power plants and geologically store the CO_2 in the geographically proximate Navajo sandstone saline formation. A rough schematic of the proposed project, as it is currently envisioned and on which this analysis is based, is shown below as Figure 60. The analysis conducted by the project team and described in more detail in Appendix C is by necessity conceptual. It identifies and details

[4] Subsequent research has broadly confirmed the 2013 study's results. In a 2017 study, researchers evaluated expert views of CCS risk perception in three European countries. Perceived barriers across countries and experts included the high cost of implementing technologies, the slow development of policy and regulation, the absence of storage sites, and general liability. *See generally* Farid Karimi & Nadejda Komendantova, *Understanding Experts' Views and Risk Perceptions on Carbon Capture and Storage in Three European Countries*, 82 GEOJOURNAL 185 (2017).

overarching categories of applicable law and regulation, because more concrete application of that law to the proposed project cannot be achieved until the specific contours and location of the project are delineated following more in-depth geologic analysis, at a later date.

CCS occurs in three industrial segments: first, CO_2 *capture*; second, CO_2 *transport*; and, finally, CO_2 *storage*. Consistent with the scope of this Phase I study, this portion of the report addresses legal, liability, and regulatory barriers for transport and storage.

This section of the report is organized as follows. It first addresses use of the land necessary for both CO_2 transport and storage, including surface land use, subsurface use, and Bureau of Land Management (BLM) regulation.[5] It then discusses potential liability associated with geologic storage of CO_2 as part of CCS technology, including permitting under the Safe Drinking Water Act (SDWA). Because the proposed CarbonSAFE Rocky Mountain project is proximate to federal land and will likely require federal permits, we then discuss application of the National Environmental Policy Act (NEPA). Finally, other generally applicable legal and regulatory requirements are discussed, along with key lessons learned from parallel CCS projects.

4.1 LAND USE

Both surface and sub-surface access for CCS potentially implicate three general categories of land ownership near the CarbonSAFE Rocky Mountain project: privately owned lands, state owned lands, and federally owned lands. Surface uses include pipeline access connecting the CO_2 source to the injection site, as well as the injection site itself and associated infrastructure. Sub-surface use includes permanent geologic CO_2 sequestration within the receiving geologic formation, which is defined spatially by the extent of the CO_2 plume. We address surface and sub-surface rights in turn, for each type of ownership category, followed by general discussions of pore space ownership for the CarbonSAFE Rocky Mountain project as well as how to acquire access to such rights, including by negotiation (leasing, easement, or purchase) or exercise of governmental authority (eminent domain).

4.1.1 Surface Land Use

As noted, three different types of landowners possess surface property rights near the proposed CarbonSAFE Rocky Mountain project: private, state, and federal. Acquiring rights to use the surface of land owned or managed by these entities will necessarily involve different processes.

Private Ownership

Private landowners are generally free to alienate all or some subset of the rights that they hold. In the law, property often is referred to as a "bundle of sticks." This means that a landowner may sell, lease, or otherwise grant rights to the use of the surface estate while still retaining overall ownership of the property. With respect to the CarbonSAFE Rocky Mountain project, then, if access is needed to privately owned surface lands, negotiated transactions would likely need to be used, particularly since eminent domain authority has not been developed fully in the CCS

[5] CarbonSAFE Rocky Mountain is not anticipating use of the surface of National Forest System land.

context, and the cost of such proceedings would likely be prohibitive both financially and in terms of potential project delays.

State Ownership

The Utah School and Institutional Trust Lands Administration (SITLA) manages most, if not all, of Utah's surface and sub-surface estate within the vicinity of the proposed CarbonSAFE Rocky Mountain project area. State law provides mechanisms for the sale of state lands, but obtaining a lease or easement would likely be a more efficient solution. With respect to pipelines transmitting CO_2 from the power plant to the injection site, rights-of-way may already be in place, depending on what transport path is selected. An existing easement could presumably be amended to accommodate additional pipeline infrastructure. Alternatively, a new easement could also be acquired.

Federal Ownership

The process for acquisition of rights to utilize federally managed surface resources is relatively well-defined. Indeed, over the last several decades, the Department of the Interior promulgated an extensive series of regulations that makes securing a surface lease or utility right-of-way on the type of federal lands proximate to the proposed CarbonSAFE Rocky Mountain project comparatively routine.

All federal lands (both surface and sub-surface) within the project area are believed to be under BLM administration. The Federal Land Policy and Management Act[6] (FLPMA) requires the BLM to "prepare and maintain on a continuing basis an inventory of all public lands and their resource[s]."[7] Based on this inventory, the BLM must "develop, maintain, and, when appropriate, revise land use plans which provide by tracts . . . for the use of the public lands."[8] These plans, commonly referred to as Resource Management Plans (RMPs), establish the management direction for a defined region of public land, although in practice such regions can be quite large, covering millions of acres. Critical RMP decisions include, among other things, which lands will be available for mineral development, which lands will be managed to emphasize resource protection, and what management stipulations are required to balance BLM's multiple use and sustained yield mandates across the federal landscape.[9]

The Price RMP applies to the CarbonSAFE Rocky Mountain project area and was most recently revised in 2008. It contains management stipulations applicable to lands proximate to both the primary and secondary injection sites of the CarbonSAFE Rocky Mountain project, likely pipeline corridors and the injection site(s). The Price RMP contains mapped management stipulations for approximately eighty different resources. As RMP consistency is a central focus

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[6] 43 U.S.C. §§ 1701–1787 (2012).
[7] *Id.* § 1711(a).
[8] *Id.* § 1712(a).
[9] *Id.* § 1701(a)(7).

of any BLM lease or right-of-way approval, we reviewed[10] the requirements contained in the Price RMP applicable to both the primary and secondary project sites.[11]

Hunter Power Plant (Primary CO_2 Source)

The Hunter Power Plant is located on privately owned lands south of the town of Castle Dale. CO_2 injection and geologic sequestration would likely occur west of Castle Dale, at the Buzzards Bench site. Injection is likely to occur on state trust lands that are surrounded by BLM-managed public lands. CO_2 would be transported via pipeline as shown in Figure 69. Further investigation will be needed to confirm that this right-of-way could serve the project. Alternatively, CO_2 could be piped to the Drunkards Wash oil field approximately eighteen miles to the north, also as shown in Figure 69. Lands proximate to the Drunkards Wash injection site are largely managed by SITLA, with a parcel of BLM-managed lands existing immediately east of the injection site. The Drunkards Wash site is discussed in more detail below, in conjunction with the Huntington Power Plant.

The RMP includes oil and gas surface use stipulations that are uniquely important to the project, as these stipulations apply much more broadly than their name might suggest. The RMP explains:

> The Approved RMP specifies restrictions for permitted activities to resolve concerns regarding the impacts of these uses. These conditions apply not only to oil and gas leasing, but also apply, where appropriate, to all other surface disturbing activities associated with land-use authorizations, permits, and leases, including other mineral resources.[12]

BLM-managed lands in the Buzzards Bench area are generally open to mineral development under "standard lease terms and conditions" or under "minor constraints."[13] Standard lease terms and conditions are the least restrictive category of stipulations and allow the BLM to require the

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[10] To conduct the review, we mapped the approximate location of the Hunter and Huntington power plants, the primary and secondary injection sites, and the approximate route for a pipeline connecting the power plants with the associated injection site. We then compared those maps with resource maps contained in the Price RMP and identified the resources most likely to constrain project development. Only those resource that were identified as likely to impact project development are addressed here.

[11] As noted, our analysis is by necessity conceptual in nature, which is particularly pertinent with respect to BLM permitting. As the location and contours of the CarbonSAFE Rocky Mountain project are more clearly defined via further geologic study, evaluation of the applicable RMP will need to be updated based on that more detailed information, once that information becomes available and is needed for use, such as in a Phase II study of the proposal. CCS operators should also bear in mind that not all management constraints can be mapped at the scale or resolution considered in an RMP. Project proponents should meet with BLM officials to identify any additional constraints that may exist prior to project implementation and development.

[12] BUREAU OF LAND MGMT., DEP'T OF THE INTERIOR, PRICE FIELD OFFICE RECORD OF DECISION AND APPROVED RESOURCE MANAGEMENT PLAN 40 (2008) (hereinafter the Price RMP).

[13] *Id.* at Maps R-24 and R-26.

operator to move proposed facilities by up to 200 meters and prohibit new surface disturbing operations for up to sixty days per year.[14] "Minor constraints" may include timing limitations, controlled surface use stipulations, or lease notices that could result in a cumulative timing limitation of three to six months.[15]

The BLM applies a Visual Resource Management classification system to describe limits on visual impacts allowed across the landscape. Lands near Buzzards Bench are subject to Class 3 and Class 4 stipulations, which are generally facilitative of more intensive forms of development. Class 4 areas are managed to "provide for management activities which require major modification of the existing character of the landscape. The level of change to the characteristic landscape can be high."[16] The BLM manages Class 3 areas to "partially retain the existing character of the landscape. The level of change to the characteristic landscape should be moderate."[17]

With respect to ecological considerations, few riparian areas are identified in the RMP as proximate to the injection site, with the exception of two riparian areas north of Orangeville and one riparian area west of Castle Dale. Impacts to riparian areas, wetlands, and waters of the United States are regulated under the Clean Water Act and may require additional permitting. Care should be taken to identify all wetland areas, surface waters, and intermittent drainages; to avoid such areas whenever possible; and to obtain appropriate permits for unavoidable impacts. Given the resolution of mapping contained in the RMP, CCS operators should not assume that RMP mapping of aquatic resources is complete or accurate.

Lands west of the Buzzards Bench injection site are characterized by a mix of sagebrush and Pinyon-Juniper cover. These lands provide mule deer habitat that is mapped as part of the Big Game Crucial Habitats layer contained in the Price RMP.[18] The Price RMP does not identify either winter habitat or crucial value nesting or brood rearing habitat for the greater sage grouse in the general area.[19] No crucial year-long white-tailed prairie dog habitat has been identified in the area.[20] Similarly, the Price RMP does not identify any designated critical habitat for threatened or endangered species, or state wildlife management areas in the immediate vicinity of Castle Dale.[21] Areas of Critical Environmental Concern, Wilderness Study Areas, and Non-WSA Lands with Wilderness Characteristics have not been identified in the Orangeville area.[22]

Huntington Power Plant (Secondary CO_2 Source)

The Huntington Power Plant, considered the secondary source for this proposed project, is located north of the Hunter Power Plant and northwest of the town of Huntington. The

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[14] 43 C.F.R. § 3101.1-2 (2017).
[15] Price RMP, *supra* note, at Map R-26.
[16] *Id.* at Tbl. 3-12.
[17] *Id.* at Map R-5.
[18] *Id.* at Map R-8.
[19] *Id.* at Map R-6.
[20] *Id.* at Map R-9.
[21] *Id.* at Map R-7.
[22] *Id.* at Maps R-11, R-28, and R-29.

Huntington Power Plant is located on private land and ringed by private and SITLA-managed lands. The approximate CO_2 injection site is roughly thirteen miles northeast of the power plant, in the Drunkards Wash oil field. Lands proximate to the injection site are largely managed by SITLA, with a BLM-managed lands existing largely to the east of the injection site.

The Price RMP identifies a utility corridor extending to the southeast from the approximate location of the Huntington Power Plant, to points south and southwest of the town of Huntington. From there, rights-of-way extend to the northeast along Utah State Highway 10, and due north.[23] Either route could provide access to the Drunkards Wash Field, though transport distances would increase significantly over those associated with the Hunter Power Plant.

There is generally less BLM-managed land proximate to the Huntington Power Plant compared to the Hunter Power Plant. What BLM-managed lands do exist near the Drunkards Wash injection site are generally managed under "minor" surface constraints that could limit surface-disturbing activities for three to six months of the year.[24] Visual Resource Management stipulations for BLM-managed lands due east of the likely injection site are unlikely to pose a constraint, as they are managed to "provide for management activities which require major modification of the existing character of the landscape. The level of change to the characteristic landscape can be high."[25] The Price RMP identifies riparian habitat near the likely injection site and, as with the Hunter Power Plant site, care should be taken to identify and avoid wetlands, surface waters, and intermittent drainages. Where these features cannot be avoided, additional permitting will be required.

4.1.2 Subsurface Land Use

In addition to use of surface land for CO_2 transport and injection, CCS projects also implicate use of the subsurface. These issues are somewhat more complicated than the surface land issues. Typically, the question boils down to ownership of the subsurface lands. However, this ownership question can be complicated for a variety of reasons. First, a situation may arise where there is a different owner of the surface land than the subsurface land—a situation known as the "split estate" question. Second, the subsurface estate itself may be subdivided further into component estates based on the existence of specific minerals or other geological characteristics. Third, the subsurface owner may have leased some or all of the subsurface estate, potentially creating overlapping mineral interests. Ownership of the subsurface estate often is referred to as ownership of the "pore space": the "spaces within a rock body that are unoccupied by solid material."[26] This is the portion of the subsurface that geologically stored CO_2 will occupy.

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[23] *Id.* at Map R-21.
[24] *Id.* at Maps R-25 and R-26.
[25] *Id.* at Map R-5.

[26] *Definition: Pore Space*, www.idahogeology.org/services/hydrogeology/portneufgroundwaterguardian/my_aquifer/vocab/vocab_text/pore_space.html (last visited Jul 29, 2017).

Historically, property rights have been referred to as "sticks" in a "bundle" of various rights.[27] Different rights can be separated from each other in a legal sense; each such right is referred to as a "stick" in the overall "bundle" of property rights, and it is appropriate to look at pore space ownership as its own "stick" in the property bundle.[28]

Generally, the owner of a fee simple estate (*i.e.*, full ownership of the surface and sub-surface land) will own the pore space beneath their land.[29] This is an application of the *ad coelum* doctrine, which historically stood for the proposition that an owner of a surface estate owns from the depths of the earth to the extent of the universe. As society has evolved, courts have recognized limits on the *ad coelom* doctrine. For instance, courts typically now place a ceiling on the ownership of a surface owner's airspace. However, judicial decisions have not attempted to place a floor on the ownership of the subsurface estate underlying a fee-simple property owner's land. Therefore, generally, the owner of a fee-simple estate will own the pore space that lies underneath a given tract of land.

This quickly becomes murkier in split estate or competing use issues, situations very familiar to the oil and gas arena. Split estates are created "when the surface estate and all or part of the mineral estate in a particular parcel are not owned by the same party."[30] Internationally, the majority of countries reserve ownership of the mineral and other subsurface estates to the sovereign government. In the United States, however, there is widespread private ownership of subsurface estates.[31] The rise in usage of pore space outside of the context of CCS necessitated resolution first in the courts and later, in a minority of states, by legislation. Typically, two distinct rules guide the analysis for resolving split estate questions: the American Rule and the English Rule. Understanding these rules is important because ownership of pore space is not a settled issue, particularly with respect to ownership of pore space for CCS.[32]

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[27] *See* M. GRANGER MORGAN & SEAN T. MCCOY, CARBON CAPTURE AND SEQUESTRATION 95 (2012).

[28] *See* Trae Gray, *A 2015 Analysis and Update on U.S. Pore Space Law—The Necessity of Proceeding Cautiously With Respect to the "Stick" Known as Pore Space*, 1 OIL & GAS, NAT. RESOURCES & ENERGY J. 277, 279 (2015).

[29] *See* MORGAN & MCCOY, *supra* note 33, at 95

[30] Kendor P. Jones et al., *Split Estates and Surface Access Issues*, *in* LANDMAN'S LEGAL HANDBOOK, ch. 9 (Rocky Mt. Min. L. Fdn., 5th ed. (2013).

[31] *Id.*

[32] This report draws heavily from MORGAN & MCCOY, *supra* note 27; Alexandra B. Klass & Elizabeth J. Wilson, *Climate Change, Carbon Sequestration, and Property Rights*, 2010 U. ILL. L. REV. 363, 381 (2010); STEFANIE L. BURT, WHO OWNS THE RIGHT TO STORE GAS: A SURVEY OF PORE SPACE OWNERSHIP IN U.S. JURISDICTIONS (2012); and Gray, *supra* note 34.

The American Rule

The American Rule cleaves the mineral estate from the pore space,[33] regardless of whether they are physically bound together, and vests ownership of the pore space with the surface estate owner.[34] This rule developed through applying common maxims used to determine the ownership of the subsurface generally.[35] These maxims include the *ad coelum* doctrine, the narrow drafting of conveyances and narrow interpretation of those conveyances by courts,[36] and a presumption of a reservation of rights by surface holders when they are not expressly conveyed or necessary to reduce and capture a given mineral resource.[37]

Because no court has dealt with the issue of pore space solely in the CCS context, application of the American Rule to CCS must be guided by other subsurface storage uses, such as natural gas storage. The case of *Ellis v. Arkansas Louisiana Gas Co.* provides an example[38] There, the court was asked to determine from whom a natural gas storage injector needed to obtain permission to store its natural gas, where a split estate existed. Plaintiffs owned seventy-eight acres of a surface estate in Oklahoma.[39] The mineral estate had been severed through a series of deeds. The gas reservoir had been depleted, so the mineral estate holder had been using the reservoir to store gas. The court held that the surface estate owned the subsurface pore space created by the depleted gas reservoir. This was because the legal instruments that severed the mineral estate conveyed the right to explore and develop the minerals in the estate but said nothing about who owned the depleted reservoir.[40] As a result, under the American rule, ownership of that space remained with the surface estate owner—and that was from whom the gas storage operation needed to acquire storage rights.

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[33] Ellis v. Arkansas Louisiana Gas Co., 450 F. Supp. 412, 421 (1978), *aff'd*, 609 F.2d 436 (10th Cir. 1979).

[34] This principle is likened to excavating a basement. If party A contracts with party B to remove the dirt underneath a tract of land owned by party A, party B does not obtain title to the newly created space. Accordingly, the owner of a mineral estate cannot lay claim to the pore space they create after extraction of gas or other mineral deposits, or even when the space is naturally occurring rather than created through extraction. *See, e.g.*, *Burlington Res. Oil & Gas Co., LP v. Lang & Sons Inc.*, 259 P.3d 766, 771 (Mont. 2011).

[35] *See* Owen L. Anderson, *Geologic CO_2 Sequestration: Who Owns the Pore Space?*, 9 WYO. L. REV. 97 at 99–100 (2009); *see also* MORGAN & MCCOY, *supra* note 33, at 95–96.

[36] *See Ellis*, 450 F. Supp. at 420.

[37] *See* MORGAN & MCCOY, *supra* note 33, at 95–96; *see also Ellis*, 450 F. Supp. at 421.

[38] *Ellis*, 450 F. Supp. 412 at 414.

[39] *See Ellis*, 609 F.2d at 439.

[40] *Ellis*, 450 F. Supp. at 421.

4.1.3 Pore Space Ownership for a Utah CCS Project

A majority of oil-producing states follow the American rule.[41] This is often via development of the common law. Many jurisdictions have yet to codify this principle, instead resolving pore space issues in court. A small number of states have enacted legislation that places pore space ownership in the surface estate. Utah, however, has not adopted legislation defining pore space ownership, and no case law from Utah directly addresses ownership in the CCS context.

While Utah law is not entirely clear which entity owns the pore space into which CO_2 would be injected, the surface estate owner or the mineral estate holder, the Utah Legislature has enacted legislation regarding natural gas storage which implies that pore space should be considered part of the surface estate. The Utah Legislature has directed the state Department of Natural Resources, to create pore space ownership and other rules for CCS.[42] Utah began to undertake an effort to adopt such rules in 2009 and 2010. However, after the EPA announced its final rule for Class VI Underground Injection Control wells under the Safe Drinking Water Act, Utah put its plans to adopt CCS rules on indefinite hold. Notwithstanding that hold, recommendations from the state's CCS Rules Working Group[43] suggest that Utah likely would have adopted the American rule with respect to CCS pore space ownership.[44]

Further, Utah Code § 78B-6-501(6)(d) grants the mineral estate owner the right to condemn "any subsurface stratum or formation" for natural gas storage. By granting the mineral estate owner the power of condemnation for pore space to store natural gas, the legislature necessarily concluded that the mineral estate owner did not already own the pore space—if they did, there would be no need for the power of condemnation. Since the strong implication from § 78B-6-501(6)(d) is that pore space does not belong to the mineral estate owner, it logically follows that, in accord with the American rule, pore space is owned by the surface estate owner in Utah.

In Utah, an argument could also be made that, as applied to state lands, conveyance of pore rights must be express—a position again consistent with the American rule. Under SITLA's mineral reservation statutes, pore space must be reserved to the state when SITLA sells lands to private parties. Utah Code § 53C-1-102 imposes several "fiduciary duties" on SITLA, including a duty to "manage the lands . . . in the most prudent and profitable manner possible[.]"[45] Further,

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[41] *See generally* BURT, *supra* note 38; *see also* Gray, *supra* note 34.

[42] *See* UTAH CODE § 54-17-701.

[43] *See* UTAH CODE § 54-17-701 (creating this CCS Rules Working Group); *see also* Utah Dep't of Envtl. Quality, Utah Dep't of Natural Resources, Recommended Rules for Carbon Capture and Geologic Sequestration (Nov. 15, 2010), https://pscdocs.utah.gov/misc/miscindx/documents/RecommendedRulesforCarbonCaptureandGeologicSequestration11-15-2010.pdf (hereinafter Utah Rec. Rules).

[44] *See* Utah Rec. Rules, *supra* note 61. It appears that no further action is being taken regarding adoption of the rules.

[45] UTAH CODE § 53C-1-102.

sales of state lands “[must] contain . . . a [coal and mineral] reservation.”[46] Excepted from that reservation are “common varieties of sand, gravel, and cinders”—but not exempted are “deposits which are valuable because the[y] contain[] characteristics which give it distinct and special value.”[47] Therefore, if pore space is of distinct and special value, it may be statutorily reserved to SITLA. While this provision applies only to land sales, SITLA may apply the same principle when issuing mineral leases.

As part of Phase II, the CarbonSAFE Rocky Mountain Team should review all existing mineral leases proximate to the injection site, whether those leases were issued by the BLM, SITLA, or a private entity, and determine whether any of these leases address pore space use. If leases fail to indicate pore space ownership, the weight of authority implies that the surface owner also owns the pore space, and that ownership must be addressed in turn as part of legal approval for CCS operations.

4.1.4 Obtaining Land Use Rights

Because accessing private, state, and federal lands—both at the surface and subsurface—may be necessary to execute the proposed CarbonSAFE Rocky Mountain project, it is necessary to understand the process for obtaining such rights. This subsection describes available processes. At the outset, however, it is worth noting that particularly with respect to subsurface property rights, obtaining pore space remains a rather novel legal question. The state of Utah and the BLM have never granted an interest in pore space solely for the purpose of injecting CO_2 for permanent geologic sequestration. Therefore, each of the avenues presented below should be considered as options only, and not necessarily the only way to obtain an interest in pore space, while also recognizing that the processes could be altered when relevant decisional bodies are faced with the new situation of CO_2 injection and storage.

Acquiring Private Land Use Rights

Generally, fee-simple landowners are free to alienate or dispose of their property, including a subset of their rights. There are several ways to go about this, but they break down into two broad categories: agreement via negotiation and acquisition via governmental authority (*i.e.*, eminent domain).

Agreement

Three primary mechanisms tend to be used to acquire property rights from a fee simple landowner: leases, easements, and outright conveyances. Each of these could be used for both surface and subsurface rights acquisition.

Leases have been used in the mineral context for some time and are particularly common in the oil and gas context. Adapting this established framework could facilitate a CCS project. A lease for surface access would allow for ingress and egress, and use of the land to, for instance, transport CO_2 or inject it. For subsurface rights, obtaining a right to occupy the pore space would

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[46] *Id*. § 53C-2-401.

[47] *Id.*

require the drafting and execution of a pore space lease. When using a lease, the operator should be mindful of the permanence of the sequestered CO_2 and the potential for interference with other uses. Presumably, oil and gas leases could serve as a starting point for tailoring a CO_2 storage lease.

An easement may provide a more permanent and elegant solution than a lease. Easements are particularly common in the energy and utility infrastructure context, where they are typically referred to as rights-of-way (ROW). Easements are "created by express words of either a formal grant or of a reservation or exception in a conveyance of land."[48] Like a lease, an easement does not create an ownership interest in the subject property, but rather, only the mere right to use the property in a given manner. The advantage of an easement is that it could exist in perpetuity until abandoned. This could be beneficial at the surface and subsurface level, and for pore space rights, may help navigate around the issue of permanence.

Lastly, a CCS operator could obtain the right to use land from an outright conveyance through a deed or other similar instrument. Use of such a mechanism is rather uncommon in the surface land context where the land is of significant value, and particularly where the property in question is large or the acquisition of the property will split the larger tract. In the subsurface context, however, the advantage of this route would be that ownership of the pore space will remain with the CCS operator in perpetuity. Still, this could be a costlier approach than the lease or easement options.

Eminent Domain

Eminent domain allows the taking of private property for public use by the state, municipalities, private individuals, or corporations that are authorized to exercise functions of a public character. Eminent domain can be utilized to obtain surface rights, subsurface rights, or both. Eminent domain authority is not available against the federal government unless expressly authorized by an act of Congress.[49]

Utah's eminent domain statute does not expressly grant a CCS operator authority to condemn certain real property.[50] The touchstone of eminent domain authority is a taking for a public use. Utah's eminent domain statute lists several statutory public uses, including "any subsurface stratum or formation in any land for the underground storage of natural gas."[51] Uses identified in

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[48] UTAH REAL PROPERTY LAW § 12.02 (Lexis).

[49] Utah Power & Light Co., 243 U.S. 389, 405 (1914). While the Utah Legislature has enacted legislation authorizing the use of eminent domain against the federal government, *see* UTAH CODE § 78B-6-503.5, this statute is almost certainly unconstitutional. As the Utah Office of Legislative Research and General Counsel warned the Legislature before enactment, "[T]he state has no standing as sovereign to exercise eminent domain or assert any other state law that is contrary to federal law on land or property that the federal government holds under the Property Clause." H.R. 143, 2012 Gen. Sess. (Utah 2012) (fiscal note appended to the introduced version of the bill).

[50] *See generally* UTAH CODE §§ 78B-6-501 *et seq.* (2017)

[51] *Id*. § 78B-6-501(6)(d).

the statute are "not exclusive . . . and merely establish a general starting point."[52] Therefore, if a CCS operation could demonstrate that geologic sequestration is a public use, the operator could conceivably claim authority to condemn property.[53] It is also noteworthy that the CCS Rules Working Group recognized the lack of express eminent domain authority for CCS operators, and recommended expansion of several areas of the eminent domain statute.[54]

Second, Utah law also provides that "the right of eminent domain may be exercised on behalf of . . . any occupancy in common by the owners or possessors of different mines, quarries, coal mines, mineral deposits, mills, smelters, or other places for the reduction of ores, or *any place for* the flow, *deposit* or conduct of tailings or *refuse matter*[55]. While tenuous, a CCS operator—or coal mine operator—could argue that CO_2 should be classified as refuse matter to coal production. The argument would be that what is being sought is a place to dispose a product that, for commercial purposes, has little value. Thus, by analogy, CO_2 arguably could be considered akin to waste or, in statutory terms, "refuse matter." In response, an owner of condemned property would argue that such a reading of the statute is not in character with its intended meaning and, further, that CO_2 storage is not in the public use.

Given the untested nature of these arguments, the much safer route for a CCS operator seeking to use eminent domain authority would be to obtain a legislative amendment of the existing law, in accord with the CCS Rules Working Group's recommendation.[56] That is, an attempt to exercise eminent domain authority without such a legislative enactment would carry a high risk of litigation.

Another downside of using eminent domain bears mention. Eminent domain proceedings tend to provoke litigation and delay. Further, even if successful, they require payment for the resources seized, and valuation can invite further litigation. Negotiated transactions therefore appear highly preferable for CCS purposes.

Acquiring State Land Use Rights

A portion of the land granted to Utah at statehood is held by the state in trust for the benefit of the public schools and institutions.[57] These lands are now managed under the authority of the State of Utah School and Institutional Trust Lands Administration (SITLA).[58] SITLA lands are ubiquitous in and around the location of the proposed CarbonSAFE Rocky Mountain project.

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52 *Utah Dep't of Transp. v. Carlson*, 2014 UT 24, ¶ 20, 332 P.3d 900, 904; *Salt Lake City Corp. v. Evans Dev. Grp., LLC*, 2016 UT 15, ¶ 11, 369 P.3d 1263, 1266.

53 *See, e.g.*, *Watkins v. Somonds*, 354 P.2d 852 (Utah 1960); *Jacobsen v. Memmott*, 354 P.2d 569 (Utah 1960).

54 *See* Utah Rec. Rules, *supra* note 61, at att. 2.

55 UTAH CODE § 78B-6-501(6)(f).

56 *See* Utah Rec. Rules, *supra* note 61, at Att. 2.

57 *See* UTAH CODE § 53C-1-102.

58 *See id*. §§ 53C-1-101 *et seq*.

There are several ways in which a private entity could obtain ownership or an interest in SITLA-managed lands. These fall into three broad categories that track the negotiation-based options for obtaining access to private lands: easements, leases, and land sales.

Notably, of these three avenues, private parties typically obtain an interest in SITLA lands through a variety of leases, including agricultural, grazing, and mineral leases. Commercial and renewable energy leases are also common. Obtaining the right to pore space under current SITLA regulations, however, would be a matter of first impression and would necessarily involve conferring and negotiating directly with SITLA.

Easement

To obtain an easement, a CCS operator would need to apply to SITLA under the procedures delineated in Utah Admin. Code R850-40 *et. seq*. Much of the language in these provisions suggests that these easements are not permanent, but it appears that SITLA may extend the life of an easement into perpetuity.[59] The minimum cost to the CCS operator would be the cost of administering the easement. If a CCS operator obtains an easement, the operator can assign the easement, but only with approval from SITLA.[60] Easements are managed by the Surface Group at SITLA and are commonly used for electrical lines, pipelines, and roads.

While technically allowable under SITLA's authority, easements are not commonly used when developing a resource. Instead, an entity typically requests a lease or a permit. A CCS operator is arguably developing the pore space estate, not merely using it passively, as is done for utility lines or roads. After the CO_2 is injected, no one could further use the pore space, meaning that it is depleted, whereas after a pipeline is no longer needed, the land it has been occupying can be used for other purposes since the pipeline can be removed. Therefore, a lease would be a more logical—and perhaps more likely—way to develop a CCS project on SITLA lands, particularly with respect to subsurface rights as opposed to CO_2 transport.

Lease

Utah Admin. Code R850-30-100 *et seq*. defines SITLA's authority to issue special use leases. Special use leases may be required for pipelines or other infrastructure needed for CCS operations. Industrial special use leases are issued for periods of up to fifty-one years,[61] but in extraordinary circumstances, the lease term can be extended to ninety-nine years.[62] A lease for CCS use of pore space would most likely be classified as a special use lease because it is not within the standard definition of a mineral lease.[63] To obtain a special use lease, the applicant must follow procedures listed in Utah Admin. Code R850-30-500. The applicant may be required to submit a bond for reclamation as well as lease payments.[64] The lease rate will be based on market value and income-producing capability.[65]

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59 UTAH ADMIN. CODE R850-40-800 (2016).
60 *Id.* R850-40-1600.
61 *Id.* R850-80-200(3)(e); R850-80-200(2).
62 *Id.* R850-80-200(2).
63 *Id.* R850-80-100.
64 *Id.* R850-80-800.
65 *Id.* R850-80-400(1).

Land Sale

State law vests SITLA with authority to sell trust lands under its management. There are two avenues by which SITLA may sell trust lands: a public sale or a negotiated sale.[66] SITLA commonly reserves the mineral estate during land sales, and most sales involve developable lands rather than linear features. Whether SITLA would entertain a proposal to sell lands for either CCS or for a pipeline is unclear, but it appears less likely than a lease. This is because a land sale permanently divests the property from SITLA, whereas a lease extracts income from the property while preserving the corpus of the land for future income-generating activity. As a trustee for the state's lands, SITLA has a fiduciary obligation to maximize benefit to the state from the trust lands. This likely explains why SITLA tends to reserve mineral rights when it engages in land sales.

Acquiring Federal Land Use Rights

Several different entities manage federally owned lands within the United States. In Utah, most federally owned land is managed by the Bureau of Land Management (BLM) and the U.S. Forest Service, and the BLM is responsible for the management of the federal subsurface mineral estates.

Both the BLM and the Forest Service manage lands under the broad and flexible principles of multiple use. That is, the statutes governing these agencies require them to seek to accommodate a balance of uses on federal lands, with the general idea in mind that the lands will produce a "sustained yield."[67]

Two primary authorities govern which lands the BLM can dispose of or grant usage rights to: The Federal Land Planning and Management Act (FLPMA)[68] and the Mineral Leasing Act (MLA).[69] FLPMA would govern rights-of-way needed for the transport phase of a CCS operation on federal lands managed by the BLM. Likewise, a CCS operator that is not pursuing an enhanced oil recovery project would obtain the right to use pore space under FLPMA. If the project also involves oil and gas development, the rights would be obtained under the MLA. The National Forest Management Act governs surface uses of lands managed by the Forest Service while the BLM manages minerals beneath Forest Service managed land surface pursuant to the MLA.

As in the state context, acquisition of rights of way for pipeline or other utility or transport uses is quite common on federal lands. However, use of federal lands for CO_2 storage would be a rather novel proposition. To our knowledge, no entity operates a CCS project on BLM land for

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[66] *See id.* R850-80-610–615.

[67] 43 U.S.C. §§ 1701(a)(7), 1712(c)(1); 16 U.S.C. § 529.

[68] 43 U.S.C. §§ 1701 *et seq.*

[69] 30 U.S.C. §§ 181 *et seq.*

the sole purpose of CO_2 sequestration.[70] The lack of clear precedent for the CarbonSAFE Rocky Mountain project could complicate permitting efforts.

A CCS operator could obtain a right-of-way to transport or store CO_2 under FLPMA, which gives the BLM broad authority to issue rights-of-way. FLPMA states:

> The Secretary . . . [is] authorized to grant, issue, or renew rights-of-way over, upon, under, or through such lands for . . . such other necessary transportation or other systems or facilities which are in the public interest and which require rights-of-way over, upon, under, or through such lands.[71]

To obtain a right of way from the BLM, a CCS operator would need to meet with the local BLM office, conduct a pre-planning meeting, complete a Standard Form 299 (SF299),[72] and pay a processing fee.[73] If the application is approved, the BLM may require a bond, and the CCS operator would need to pay monitoring fees during development, plus annual rent for the life of the project.

According to employees at the BLM's Utah office, FLPMA could be a means of obtaining a right not only to transport CO_2 across BLM lands but also potentially to use BLM pore space for CO_2 storage (so long as the project is outside of an oil and gas context, such as enhanced oil recovery). Although BLM officials have preliminarily indicated that the FLPMA right-of-way process could possibly be used for CO_2 storage, to date the BLM has not issued any ROW for a project of this nature. Such a first-of-kind ROW grant could be seen by the BLM as having a potential precedent-setting effect, and thus, would likely require input from high-ranking BLM or Department of the Interior officials. This could delay ROW issuance.

4.2 LIABILITY RISK

Any activity involves an element of risk. For the proposed CarbonSAFE Rocky Mountain project, these risks exist for both the transport and storage phases of CCS. With respect to transport, the primary risk is that there will be some kind of accident as CO_2 is being moved. Such an accident could, for instance, harm employees or contractors involved in achieving transport, or the general public or surrounding lands, if a leak occurred. Transport of CO_2 is governed by safety regulations implemented by the Pipeline and Hazardous Materials Safety Administration (PHMSA). This section of the report focuses on that regulation, recognizing that

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[70] Our analysis assumes that the sole purpose of the proposed CarbonSAFE Rocky Mountain CCS operator is to sequester CO_2 rather than to engage in further mineral development, such as through enhanced oil recovery.

[71] 43 U.S.C. § 1761(a)(7).

[72] *See* GSA Forms Library, Form: SF299, www.gsa.gov/portal/forms/download/117318 (last visited Aug 14, 2017).

[73] *See* Bureau of Land Mgmt., Division of Lands and Realty, *Obtaining a Right-of-Way on Public Lands* (Mar. 10, 2009), www.blm.gov/sites/blm.gov/files/ObtainingaROWPamphlet.pdf.

other legal frameworks for liability might apply, particularly under tort law and property law. With respect to geologic storage of CO_2, a host of issues could impact long-term liability exposure. The three main issues are ownership of injected CO_2, permitting requirements for underground injection control under the Safe Drinking Water Act, and long-term liability exposure under other environmental laws. This section addresses each in turn.[74]

4.2.1 Transport Regulation

The Pipeline and Hazardous Materials Safety Administration (PHMSA) within the Department of Transportation regulates the movement of a large array of materials via pipeline. This includes CO_2, which PHMSA regulations define as "a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state."[75] PHMSA regulation of CO_2 transport is extensive and focused on ensuring safety and the lack of accidents.[76] Here, we review six key aspects of these regulations.

Minimum Design Requirements

The PHMSA imposes minimum design requirements for new, relocated, replaced, or modified CO_2 pipeline systems. The pipeline must be "made of steel of the carbon, low alloy-high strength, or alloy type that is able to withstand the internal pressures and external loads and pressures anticipated for the pipeline system."[77] If there are segments of the system that operate under different pressure levels, the system must be designed so that components operating at lower pressures will not be overstressed.[78] The system must also account for possible external pressures, such as earthquakes, vibration, and thermal expansion and contraction.[79] All materials in the system also must be chemically compatible with CO_2 and selected for the temperature environment in which the system will operate, maintaining structural integrity.[80] The pipeline also must be designed and constructed to accommodate internal inspection devices.[81]

Construction, Inspection, and Testing

Each phase of pipeline construction and repair must be inspected by a person trained and qualified in the specific aspect of construction.[82] Beginning with initial construction, the operator

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[74] Other sources of liability exist, including but not limited to liability for an inadvertent CO_2 release from compression, transport, or injection infrastructure or from the reservoir itself. These issues are treated as the kind of generalized liability that is associated with more routine energy industry development and therefore beyond the scope of this analysis.

[75] 49 C.F.R. § 195.2.

[76] For an overview of regulatory issues of CO_2 transport for CCS, see Jennifer Skougard Horne, *Getting from Here to There: Devising an Optimal Regulatory Model for CO_2 Transport in a New Carbon Capture and Sequestration Industry*, 30 J. LAND RESOURCES & ENVTL. L. 357 (2010).

[77] 49 C.F.R. § 195.112(a).

[78] *Id.* § 195.104.

[79] *Id.* §§ 195.108, 195.112.

[80] *Id.* § 195.102.

[81] *Id.* § 195.120.

[82] *Id.* § 195.204.

is responsible for maintaining a complete inspection record for the life of the system.[83] Pipeline location, materials, components, welds, valves, and pumping equipment must all be inspected at the time of installation or construction of each segment. Likewise, breakout tanks must be inspected for adequate emergency venting or pressure relief.[84] Further, no owner may operate a pipeline or return to service any segment unless it has been pressure tested without leakage.[85] The test pressure must be maintained for at least four continuous hours at a pressure equal to 125 percent or more of the maximum operating pressure.[86] The operator must keep records of every pressure test and retain the records as long as the pipeline facility is in use.[87]

Operation and Maintenance

Each operator is responsible for the maintenance and safe operation of its pipeline system. If the operator discovers an adverse condition within the system, it must correct the condition within a reasonable time. If the condition presents an immediate hazard, the operator must cease use of the affected part of the pipeline system until it corrects the condition.[88]

The operator must maintain a manual with written procedures for conducting normal operations and maintenance, as well as protocols for abnormal operations and emergencies. The manual must be reviewed and updated annually and kept in locations where operations and maintenance activities are conducted.[89]

Each operator also must keep adequate firefighting equipment at each pump station and breakout tank area, prohibit smoking and open flames, develop and implement a written continuing public education program, establish and conduct a training program for emergency personnel, maintain current maps and records of its pipeline systems, maintain a system of communication for the transmission of information regarding the safe operation of the pipeline system, and place and maintain line markers over each buried pipeline.[90] Signs visible to the public must be maintained around each pumping station and each breakout tank area.[91]

At least 26 times per year, at intervals of no more than 3 weeks, the operator must inspect the surface conditions on or adjacent to each pipeline right-of-way.[92] Operators must also inspect all overpressure safety devices and overfill protection systems at intervals not to exceed 7.5 months, at least twice a year, to ensure that all pressure control equipment is properly functioning, remains in good mechanical condition, and is adequate for capacity and reliability.[93] Repairs must be made in a safe manner so as to prevent damage to persons or property.[94] Each operator

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[83] *Id.* § 195.266.
[84] *Id.* § 195.264.
[85] *Id.* § 195.302.
[86] *Id.* § 195.304.
[87] *Id.* § 195.310.
[88] *Id.* § 195.401.
[89] *Id.* § 195.402.
[90] *Id.* §§ 195.403-.404.
[91] *Id.* § 195.434.
[92] *Id.* § 195.412(a).
[93] *Id.* § 195.428.
[94] *Id.* § 195.422.

must also carry out a written program to prevent damage to pipeline from excavation activities, including blasting, boring, tunneling, backfilling, removal of aboveground structures, and other earth moving operations.[95]

Corrosion Control

CO_2 pipeline operators also must comply with PHMSA regulations ensuring against corrosion. Each buried or submerged pipeline must have an external coating for external corrosion control.[96] The coating material must be designed to mitigate corrosion, have sufficient adhesion, be sufficiently ductile, resist damage due to handling and soil stress, and support any supplemental cathodic protection.[97] Each buried pipeline must have cathodic protection in operation no later than one year after the pipeline is constructed as well as electrical test leads for external corrosion control.[98]

Corrosion control must be conducted regularly, with tests for external corrosion at least once every 15 months.[99] Whenever any portion of a buried pipeline is exposed, the operator must examine the exposed portion.[100] Likewise, pipeline interior must be investigated at least every 7.5 months. If corrosion reduces sufficient wall thickness, the pipe must be replaced.[101] When corrosion requiring corrective action is found, the operator must investigate circumferentially and longitudinally beyond the removed pipe to determine that further corrosion does not exist.[102]

Unless electrically interconnected and cathodically protected, all buried pipeline must be electrically isolated from other metallic structures. One or more insulating devices must be installed wherever electrical isolation of a portion of pipeline is necessary to facilitate corrosion control. Each electrical isolation must be inspected and electronically tested to assure the isolation is adequate. If an insulating device is installed in an area where a combustible atmosphere is reasonably foreseeable, precautions must be taken to prevent arcing.[103] Operators must have a program to identify, test for, and minimize damage to pipelines exposed to stray currents.[104]

Records of corrosion control must be maintained. An operator must keep current maps or records showing the location of cathodically protected pipelines, cathodic protection facilities, and neighboring structures bonded to cathodic protection systems. Records of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test must be kept with sufficient detail to demonstrate the adequacy of corrosion control measures for at least 5 years.[105]

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[95] *Id.* § 195.442.
[96] *Id.* § 195.557.
[97] *Id.* § 195.559(a)-(e).
[98] *Id.* §§ 195.563(a), 195.567.
[99] *Id.* § 195.573(a)(1).
[100] *Id.* § 195.569.
[101] *Id.* § 195.585(a).
[102] *Id.* § 195.579(c).
[103] *Id.* § 195.575(a)-(e).
[104] *Id.* § 195.577(a).
[105] *Id.* § 195.589.

Annual, Accident, and Safety-Related Reporting

PHMSA regulations require pipeline operators to submit a variety of regular and incident-specific reports. Annual safety reports are due no later than June 15 for each previous year.[106] Written accident reports, along with updates on the status of an accident, must be submitted within 30 days of the occurrence. Separate reports must be submitted for each failure that results in any (1) unintentional explosion or fire, (2) release of 5 gallons or more of CO_2, (3) death of any person, (4) injury to any person that requires hospitalization, (5) damages estimated to exceed $50,000.[107] In addition to the written report, operators must provide telephonic notice of qualifying accidents as soon as reasonably possible following the discovery of the accident. Accidents that result in the pollution of any stream, river, lake, reservoir, or other similar body of water also requires immediate telephonic notice.[108] If an accident is investigated by PHSMA or other government regulator, the operator has a duty to provide all records, information, and assistance reasonably available or necessary.[109]

Qualifications of Pipeline Personnel

Each operator must have and follow a written personnel qualification program that will, among other things, identify covered tasks, evaluate the qualifications of individuals assigned to covered tasks, provide training, allow individuals who are not yet qualified to perform a covered task under supervision of a qualified individual, and communicate changes that affect covered tasks to the individuals responsible for performing those covered tasks.[110] Additionally, each operator must maintain records that contain (1) the identification of qualified individuals, (2) the identification of the covered tasks each individual is qualified to perform, (3) the dates of the individual's current qualification, and (4) the methods of training the individual received. Records of prior/expired qualifications and of individuals no longer performing covered tasks must be retained for 5 years.[111]

4.2.2 Storage Liability

Three key issues outline the likely scope of liability for permanently sequestered CO_2. These relate to who owns the CO_2, permitting under the Safe Drinking Water Act, and potential long-term liability under both environmental and other statutory and common law.

CO_2 Ownership

A threshold question for possible liability from the storage phase of CCS is who owns the geologically deposited CO_2. That is, once the CO_2 is injected into the ground, does the injector maintain ownership of it and thus risk liability from any harm that may arise from the injected CO_2?

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[106] *Id.* § 195.49.
[107] *Id.* § 195.50.
[108] *Id.* § 195.52.
[109] *Id.* § 195.60.
[110] *Id.* § 196.505(a)-(e).
[111] *Id.* § 195.507.

The law is not clear on this question, although analogous reasoning from other areas suggests that an injector of CO_2 is likely to retain title to the gas. Indeed, ownership of injected CO_2 is not a settled issue. It has not been addressed in a published court opinion, and Utah statutory law does not address the question. However, applying property law doctrines from the natural gas context may help delineate ownership of sequestered CO_2.

Two theories have been suggested to address ownership of injected natural gas: the so-called "non-ownership" and "ownership" theories. Under the non-ownership theory, it can be reasoned that once natural gas is injected into the ground, the injector loses ownership of the resource because it is available for anyone to take. This reasoning derives from the longstanding "rule of capture," which serves as the foundation of oil and gas law. The rule of capture holds that, because oil and gas are fugitive minerals and can transverse subterranean property boundaries, 112 Building on this idea, which has long been invoked in oil and gas law in part to encourage exploration and extraction, the theory of non-ownership would hold that once the resource—here, CO_2[113, 114].

In place of the non-ownership theory, states instead have adopted the ownership theory. Under this theory, "title to natural gas once having been reduced to possession is not lost by the injection of such gas into a natural underground reservoir for storage purposes."[115] The rationale for this theory should be plain. It would be incongruous to promote natural gas extraction under the rule of capture, only to turn around and limit the producing party's incentive to extract by restricting its ability to feasibly store the extracted resource. To reach such holdings, courts have thus distinguished the geological context of injected gas from naturally occurring gas. Whereas the latter can be pulled across property boundaries through extraction techniques, the former is unlike releasing an animal into the wild because there is a "well[-]defined storage field . . . subject to the control of the storage companies[.]"[116] Accordingly, in cases where a gas has previously been reduced to possession but is later injected into a well-defined underground space capable of being maintained with integrity, title to the gas remains with the original owner.

While sequestered CO_2 is distinguishable from natural gas in that the former is part of the waste stream while the latter is an economically valuable commodity, a formidable argument can be made that the ownership theory should also apply to geologically stored CO_2. Because CO_2 is sequestered in a similar manner as natural gas is stored, application of the ownership theory would appear appropriate. Indeed, the mirror image of the policy incentives created by applying

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[112] Westmoreland & Cambria Nat. Gas Co. v. De Witt, 130 Pa. 235, 249 (1889).

[113] Hammonds v. Cent. Kentucky Nat. Gas Co., 75 S.W.2d 204, 206 (1934), *overruled by* Texas Am. Energy Corp. v. Citizens Fid. Bank & Trust Co., 736 S.W.2d 25 (Ky. 1987)

[114] Mark deFigueiredo, The Liability of Carbon Dioxide Storage 304 (Feb. 2007) (unpublished Ph.D. dissertation, Massachusetts Institute of Technology), http://sequestration.mit.edu/pdf/Mark_de_Figueiredo_PhD_Dissertation.pdf.

[115] White v. N.Y. State Nat. Gas Corp., 190 F. Supp. 342, 349 (W.D. Pa. 1960).

[116] *Id.* at 348.

the ownership theory to natural gas exist for stored CO_2 as well. For natural gas, the ownership theory preserves the incentive to extract the resource in the first instance. That is, the theory avoids the inequity of a gas producer incurring the cost of extraction but allowing another party to profit from that by taking the gas once it is stored. Similar reasoning could apply in the stored CO_2 context. It would seem incongruous to require the CO_2 owner to incur liability while the CO_2 is above ground but remove the potential of such obligations simply because the CO_2 is moved underground.

Nonetheless, a possible limit on the application of the ownership theory to stored CO_2 might derive from a factual difference between it and natural gas. Injected CO_2 could mineralize within as little as two years, depending upon the medium into which it is injected.[117] This could have significant implications for legal liability, because once the CO_2 turns into a solid, an argument could be made that any possibility of liability should be curtailed since solid rock will not leak or spread.

Safe Drinking Water Act Permitting

The Safe Drinking Water Act (SDWA) requires operators to obtain permits before conducting underground injection of certain materials. The Act relies on a cooperative federalism model whereby the EPA sets minimum standards and states develop programs to attain those objectives in light of local conditions. One such program under the Act is the Underground Injection Control (UIC) program. The UIC program aims to "protect public health and prevent contamination of underground sources of drinking water (USDWs)."[118] The program specifies six classes of well permits that may be granted to inject underground materials subject to the Act. Class VI permits are the relevant permit for CCS operations.

In Utah, the Utah Department of Environmental Quality and the Department of Natural Resources issue Class I-V UIC permits.[119] That is, these state-level agencies have received primacy from the EPA to administer permits for wells within classes I-V. Utah has not petitioned for authorization to administer Class VI UIC permits. That authority rests solely with the EPA. A

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[117] J.M. Matter et al., *Rapid Carbon Mineralization for Permanent Disposal of Anthropogenic Carbon Dioxide Emissions*, 352 SCIENCE 1312 (2016).

[118] Underground sources of drinking water are defined as "an aquifer or its portion: (a)(1) Which supplies any public water system; or (2) Which contains a sufficient quantity of ground water to supply a public water system; and (i) Currently supplies drinking water for human consumption; or (ii) Contains fewer than 10,000 mg/l total dissolved solids; and (b) Which is not an exempted aquifer." 40 C.F.R. § 144.3 (2017).

[119] Each class of UIC permits covers a different use. Class I deals with industrial and municipal waste. Class II covers enhanced oil recovery, salt water disposal, and storage of hydrocarbons that are liquid at standard temperature and pressure. Class III covers solution mining. Class IV covers hazardous wastes. And Class V covers injection of fluids not covered in other well classes.

CCS operator must therefore obtain a Class VI UIC permit from the EPA prior to injecting CO_2.[120]

Class VI Well Requirements Under the SDWA

Class VI wells are used exclusively for the injection of CO_2 into the subsurface in aid to a geologic sequestration (GS) or CCS projects. The EPA's main health and environmental concerns regarding CCS are the "[l]arge CO_2 injection volumes associated with GS, the buoyant and mobile nature of the [CO_2 stream], the potential presence of impurities in the CO_2 stream, and its corrosivity in the presence of water."[121] In addition, EPA has expressed concern about the "pressures induced by injection" from CCS, as those pressures "may force naturally occurring salty water (brine) into USDWs, causing degradation of water quality and affecting drinking water treatment processes."[122]

Class VI permits address a wide range of issues: site characterization, computational modeling of the Area of Review (AoR), periodic reevaluation of the AoR, well construction, project monitoring, comprehensive post-injection monitoring and site care, and financial responsibility requirements.[123]

Obtaining and complying with a Class VI permit under the SDWA provides important liability protection for CCS project operators. This liability protection, however, is far from universal and addresses only SDWA liability. EPA regulations make clear that "compliance with a permit during its term constitutes compliance, *for purposes of enforcement*, with Part C of the SDWA."[124] This rule, commonly referred to as a "permit shield" provision, is echoed in EPA's site closure[125] guidance documents:

> [O]nce an owner or operator has met all regulatory requirements under the UIC program for Class VI wells [at 40 C.F.R. § 146] and the UIC Program Director has approved site closure pursuant to requirements at 40 C.F.R. § 146.93, the owner or operator will generally no longer be subject to enforcement for regulatory noncompliance. However, following site closure, the owner or operator

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[120] 40 C.F.R. § 144.18.

[121] *See* U.S. EPA, *Class VI - Wells Used for Geologic Sequestration of CO_2*, www.epa.gov/uic/class-vi-wells-used-geologic-sequestration-co2#well_def (last visited Sept. 15, 2017).

[122] *Id*. at II(A)(3).

[123] *Id.*

[124] 40 C.F.R. § 144.35 (emphasis added).

[125] *See* U.S. EPA, Geologic Sequestration of Carbon Dioxide Underground Injection Control (UIC) Program Class VI Well Plugging, Post Injection Site Care, and Site Closure Guidance (Dec. 2016), www.epa.gov/sites/production/files/2016-12/documents/uic_program_class_vi_well_plugging_post-injection_site_care_and_site_closure_guidance.pdf.

> is financially responsible for any remedial action deemed necessary for USDW endangerment caused by the injection operation.[126]

In short, the EPA will not bring enforcement actions under Part C of the SDWA, which addresses protection of USDWs, once a CCS site has undergone official site closure. However, as discussed in more detail below, the rule does not shield enforcement of Part D of the SDWA, which addresses the EPA Administrator's emergency powers to address imminent and substantial endangerment to health. Nor does compliance with Part C preclude other enforcement mechanisms or different kinds of liability. As the above guidance document makes clear, CCS owners/operators remain "financial responsible for any remedial action" that becomes necessary even after site closure.[127] Another portion of EPA's SDWA guidance further reinforces this point:

> [S]ite closure does not eliminate any potential responsibility or liability of the owner or operator under other provisions of law[, or § 1431 of the SDWA[128]]. . . . Furthermore, after site closure, an owner or operator may remain liable under tort and other remedies, or under other federal statutes including, but not limited to, the Clean Air Act (CAA); the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA); and the Resource Conservation and Recovery Act (RCRA).[129]

Stiff penalties may be imposed for violating the SDWA's USDW protections. Violators are subject to civil penalties of up to $25,000 for each day of violation. If the violation was "willful," the violator may also be subject to criminal prosecution and imprisonment of not more than three years.[130]

Lessons Learned from SDWA Permitting for CCS Facilities

We reviewed permitting documents for three other CCS facilities in order to identify lessons learned from those experiences. While the CarbonSAFE Rocky Mountain project will be subject to the same procedural requirements, factual differences between the project at hand and prior CCS facilities need to be acknowledged when considering the experience at other CCS facilities.

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[126] *Id.* § 4.4.

[127] *Id.*

[128] *See id.* Under Section 1431 of SDWA, the Administrator may require an owner or operator to take necessary response measures if he or she receives information that a contaminant is present or is likely to enter a public water system or USDW and may present an imminent and substantial endangerment to the health of persons, and the appropriate state and local authorities have not acted to protect the health of such persons. The action may include issuing administrative orders or commencing a civil action for appropriate relief against the owner or operator of a Class VI well. If the owner or operator fails to comply with the order, he or she may be subject to a civil penalty for each day in which such violation occurs or failure to comply continues.

[129] *Id.* (internal citations omitted).

[130] 42 U.S.C. § 300h-2(b).

FutureGen

FutureGen involved CO_2 capture from Unit 4 of Ameren's Meredosia Energy Center, approximately 20 miles west of Jacksonville, Illinois, and was intended to be the world's first full-scale oxy-combustion clean coal repowering of an existing power plant fully integrated with CO_2 transport and permanent geologic storage. CO_2 would have been transported approximately thirty miles from the plant site to the storage location, where approximately one million metric tons per year of compressed and purified CO_2 would have been injected into the Mt. Simon saline formation for a projected twenty-year period.

FutureGen was the first full-scale CCS project in the United States to undergo SDWA Class VI permitting, and twenty-nine parties submitted comments on the draft permit to EPA. After responding to the comments, the EPA issued FutureGen a Class VI permit on March 31, 2014. As the first of such permits issued by the EPA, the agency stated throughout the permit file that particular care was taken to ensure protection of underground sources of drinking water. In addition, the EPA stated that modifications to the permit may be required as the project developed and therefore more data was acquired, despite all of requirements prior to issuing the permit. However, FutureGen 2.0 was discontinued due to funding limitations resulting from the expiration of American Recovery and Reinvestment Act funds on September 30, 2015. Despite the project's failure, the comments received may provide some indication of the kinds of issues that are likely to arise for the CarbonSAFE project.

Notably, the EPA took an exceedingly narrow view of the issues that it needed to consider during the FutureGen 2.0 UIC permitting process, focusing exclusively on protection of USDW. Whether plume migration had ceased prior to closure was oddly considered outside the scope of the permit analysis. Similarly, the EPA took the approach that Class VI rules were not concerned with pore space rights, just safety and project operation. The EPA therefore did not address pore space ownership, concluding that the permit does not prevent private rights from being asserted.

Also, of note, by statute and as acknowledged in the permit, Illinois would have taken ownership of the site ten years after the site closure. Therefore, any long-term liability associated with the project would rest with Illinois. Utah does not have such a statute and it appears that ownership of the site would remain with the operator until it disposes of the site in some way upon site closure. EPA appeared to acknowledge this in issuing the FutureGen 2.0 permit. It stated that "any remediation costs incurred in the very long term (i.e., after the non-endangerment determination and the release from post-injection site care responsibilities) is beyond the scope of the Class VI financial responsibility requirements and the UIC permitting process."

ADM

The Archer Daniels Midland Company (ADM) Illinois ICCS project involves sequestration of CO_2 generated as a byproduct of processing corn into ethanol at ADM's biofuels plant adjacent to the storage site in Decatur, Illinois. The CO_2 is collected at atmospheric pressure, compressed, and dehydrated to deliver supercritical CO_2 to the injection wellhead for storage. Injection occurs on a 200-acre site adjacent to the ethanol plant, which is also owned by ADM. While not addressed in detail in permitting documents, it appears that ADM owns the pore space into which the CO_2 would be injected. The project is designed to sequester 2.5 million tons of CO_2 over a 2.5-year period.

On May 3, 2011, the Department of Energy concluded its NEPA analysis[131] for the ADM project and issued a Finding of No Significant Impact.[132] The ADM project received the U.S. EPA's UIC Class VI injection well permit effective March 6, 2017 and started commercial operations accordingly. ADM characterized the CO_2 streams generated by this project as liquids, supercritical fluids, or gas. It will be injected into the Mount Simon at depths between 5,553 feet and 7,043 feet.

Class VI injection well permitting appeared to generate very little controversy, with only one member of the public submitting comments on the draft permit. Most relevant to the CarbonSAFE project, the commenter asserted that pore space rights must be taken into account when issuing the permit. The EPA, however, responded that under Class VI rules, it need not consider pore space rights, and the permit does not grant any real property rights. As noted above, CarbonSAFE Rocky Mountain would be wise to anticipate a higher level of scrutiny and that other federal approvals will need to address pore space ownership, even if the EPA does not address the issue directly.

4.2.3 Managing Financial Risk and Long-Term Liability

Risk exposure is a function of the likelihood of harmful event combined with the consequences of such an event, both of which are influenced by numerous site-specific factors. In this section, we treat financial risk as the economic cost of mitigating the injuries caused by a harmful event as well as compensation for unmitigable injuries associated with any such event. For purposes of risk assessment, CCS operations can be broken into four discrete phases: (1) capture, (2) transport, (3) injection and CO_2 plume stabilization, and (4) post-closure stabilization and monitoring. This analysis focuses on the transport, injection and CO_2 plume stabilization, and post-closure stabilization and monitoring phases.

Events giving rise to financial liability could take many forms, the most likely of which involve damage caused by: (1) the puncture of a CO_2 pipeline or failure of other pipeline infrastructure, (2) seismicity induced by CO_2 injection, (3) ground surface damage or surface heaving caused by injected CO_2, (4) interference with a surface owner's rights to occupy or use the ground surface (trespass), (5) interference with a sub-surface owner's rights to occupy or use the sub-surface, or infringement with development of their mineral rights (trespass on minerals), (6) contamination of an underground source of drinking water or other water source, and (7) an atmospheric release of CO_2. Loss of CO_2 containment and failure to maintain permanent sequestration, as required by regulation or contract, could also require the operator to refund payments received for sequestration. Damage to property, damage to natural resources or livestock, and injury to humans also involve potential economic costs to an operator.

The risk profile for each stage of operation underpins the range of costs and loss values associated with potential mitigation, remediation, and, as necessary, compensation for damages. The risk profile is a function of numerous phase-specific considerations. With respect to CO_2

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[131] U.S. Dep't of Energy, Final Environmental Assessment of Industrial Carbon Capture and Sequestration (ICCS) Area 1 Project, "CO_2 Capture from Biofuels Production and Sequestration into the Mt. Simon Sandstone," Archer Daniels Midland Company Decatur, Illinois (2011).

[132] U.S. Dep't of Energy, Finding of No Significant Impact for Archer Daniels Midland Company's "CO_2 Capture from Biofuels Production and Sequestration into the Mt. Simon Sandstone," Decatur, Illinois (2011).

transport, pipeline length, period of pipeline operation, CO_2 pressure, CO_2 purity, and proximate land use activities are examples of factors that could contribute to the risk associated with an unintended release. The location of an unintended release of CO_2 could also directly impact the consequences of such a release. A CO_2 release would be more likely to cause injury or property damage if it occurred in a populated area, for example.

During the injection and plume stabilization phase, the volume of CO_2 injected, the injection pressure, the length of the injection period, the geology of the receiving formation, the number and integrity of other wells penetrating the receiving formation, and the existence of underground sources of drinking water or valuable minerals all contribute to the risk profile. As with the risk profile associated with CO_2 transportation, the proximity to populated areas is also a critical factor in assessing risk. This necessarily requires consideration of current population as well as anticipated population growth.

Many of the same factors that shape injection and plume stabilization period risks impact the risk profile during the post-closure and post-CO_2-plume-stabilization period. However, in contrast to the risk profile during the injection and stabilization phase, which increases with injection volume and pressure until stabilization occurs, the post-stabilization and closure risk profile is likely to decline[133] as reservoir pressures stabilize, plume migration slows or stops, and as CO_2 reacts with brine and minerals in the rock to form bicarbonate that permanently traps that portion of the injected CO_2, as shown in Figure 61.[134]

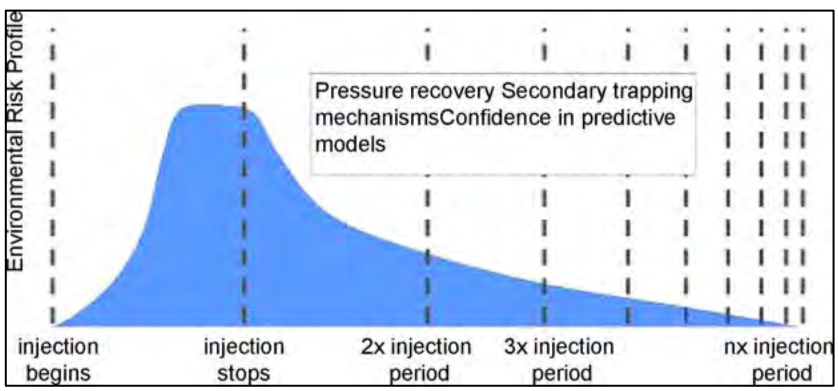

Figure 61. Life-Cycle Risk Profile for Geologic CO_2 Storage[135]

Other factors further underscore how quantifying CCS financial risks necessarily requires site-specific risk assessments. Reservoir size and permeability, injection volume and pressure, CO_2 stream purity, structural geology, faulting and reservoir perforations (including existing and abandoned wells), proximity to groundwater, proximity to valuable mineral resources, proximity

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133 *See, e.g.*, James J. Dooley et al., *Design Considerations for Financing a National Trust to Advance the Deployment of Geologic CO_2 Storage and Motivate Best Practices*, 4 INT'L J. GREENHOUSE GAS CONTROL 381, 382 (2010).

134 For a summary of CO_2-trapping mechanisms, see National Energy Technology Lab, U.S. Dept. of Energy, *How Is CO_2 Trapped in the Subsurface?*, https://www.netl.doe.gov/research/coal/carbon-storage/carbon-storage-faqs/how-is-co2-trapped-in-the-subsurface (last visited Apr. 25, 2018).

135 Figure 2 is from S.M. Benson, *Multi-Phase Flow and Trapping of CO_2 in Saline Aquifers* (Paper No. OTC 19244) in PROCEEDINGS OF 2008 OFFSHORE TECHNOLOGY CONFERENCE (2008).

to populated areas, proximity to sensitive surface resources, and pipeline length are all examples of the kinds of factors that must be considered on a case-by-case basis. Should the CarbonSAFE Rocky Mountain project proceed past Phase I, then, a quantitative risk assessment specific to the project, taking into account this site-specific information, would be necessary.

While a precise quantification of financial risk for the CarbonSAFE Rocky Mountain project is not currently possible, a review of other CCS projects may provide a rough indication of the scale of financial risk at hand. A 2011 study in ENERGY PROCEDIA provides preliminary estimates of potential public health damages during the operational phases at three proposed FutureGen sites: Tuscola, Illinois; Jewett, Texas; and Odessa, Texas.[136] As the authors explain:

> [A]ll three sites are in highly rural areas and have favorable geologic and geographic characteristics that result in relatively low damages relative to the expected cost of these facilities. Notably, the Odessa damages estimate is particularly low, reflecting the near absence of human receptors near the plant site, CO_2 pipeline, and sequestration site.[137]

Specifically, damage estimates ranged from $50,000 to $7,400,000. These estimates equate to less than $0.20 per ton of CO_2, assuming a 50-year injection period and 50 million metric tons of CO_2 stored per site. Critically, however, these valuation estimates are limited to valuation of events arising during the operational period through a defined post-injection period for each site. It is also important to note that these estimates relate only to damages associated with injuries involving public health and do not contemplate damages associated with environmental resources, such as groundwater or atmospheric releases of CO_2.

A 2014 study involving two of the same authors and also published in ENERGY PROCEDIA used a risk-based probabilistic model to estimate several categories of potential financial damages on a site-specific basis.[138] This model estimated the financial consequences arising from potential human health, safety, environmental, and business interruption events associated with CCS, in light of their anticipated site-specific likelihood and magnitude.

The authors utilized this model to quantify financial risk at the Alabama Gulf Coast-Plant Barry pilot project in Mobile, Alabama based on forty-eight potential site-specific CCS-related events at the site. The authors contemplated two scenarios: an "experimental injection well" that operated for nine years and a theoretical commercial injection well that operate for 103 years (including ten years of post-injection monitoring). Damages under the experimental injection well scenario were estimated to range up to $27 million, with a median damage estimate of $3.3 million.[139] The five events contributing the highest potential damage for the experimental scenario were:

- Failure to maintain sustained operation of capture unit, pipeline, and injection to enable storage of sufficient volumes of CO_2 (100-300 kt) to meet project goals;

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[136] Michael Donlan & Chiara Trabucchi, *Valuation of Consequences Arising from CO_2 Migration at Candidate CCS Sites in the U.S.*, 4 ENERGY PROCEDIA 2222 (2011).
[137] *Id.* at 2228.
[138] Chiara Trabucchi et. al, *Application of a Risk-Based Probabilistic Model (CCSvt Model) to Value Potential Risks Arising from Carbon Capture and Storage*, 63 ENERGY PROCEDIA 7608 (2014).
[139] *Id.* at 7612.

- Unexpected transport requirements;
- Monitoring program unable to meet monitoring intents due to movement of CO_2 and demonstration of containment;
- Decreased performance of capture unit based on fuel switch; and
- Injection pump failure or downtime.

Together, these five categories of events represented 66.5 percent of total costs across all model runs.

Modeling for the commercial scenario produced damage estimates of up to $131 million, with a median damage estimate of $6 million. The five events contributing to the highest potential damage estimated under the commercial scenario were:

- Monitoring program unable to meet monitoring intents due to movement of CO_2 and demonstration of containment;
- Unexpected transport requirements;
- Unexpected size of plume expansion (larger than anticipated) triggering permit review, expanded monitoring activities, and implementation of preventive measures on wells;
- Loss of containment due to migration along transmissive faults; and
- Return of low quality condensate that could impact water chemistry and cause problems at the plant.

Together, these five categories of events represented 83.7 percent of the total costs across all model runs. The authors also compared the cost per ton of sequestered CO_2 to those projected for the non-selected FutureGen site in Jewett, Texas, as shown in Table 20.

Table 20. Cost Per Ton Summary Model Outputs for Commercial Well Scenario and Non-Selected FutureGen Site in Jewett, TX[140]

Category	Commercial Well Scenario - Plant Barry: 30-Year Post-Injection Monitoring		Commercial Well Scenario - Plant Barry: 10-Year Post-Injection Monitoring		Non-Selected FutureGen Site Jewett, TX
	All Events	Business Risks Excluded	All Events	Business Risks Excluded	
Minimum $/ton cost	$0.00	$0.00	$0.00	$0.00	$0.00
50th percentile $/ton cost	$0.17	$0.12	$0.12	$0.07	$0.17
95th percentile $/ton cost	$1.05	$1.01	$0.92	$0.88	$0.37
99th percentile $/ton cost	$1.54	$1.49	$1.36	$1.32	$0.48
Maximum $/ton cost	$2.67	$2.85*	$2.63	$2.56	$0.74

* All Monte Carlo simulations across scenarios were conducted independently. In this case, the highest-cost trial for the "business risks excluded" scenario exceeded the costs of the highest-cost trial for the scenario where no events were excluded. This outcome has a very low probability of occurrence. $/ton assume 50MM tons CO_2 injected.

While the costs and risks associated with the CarbonSAFE Rocky Mountain project will undoubtedly differ from those associated with either the Plant Berry or Jewett, Texas facilities, it seems reasonable at this preliminary phase to plan for financial risks in the range of $1.00 to $1.50 per ton of CO_2 injected. This represents approximately the ninety-fifth to ninety-ninth percentile for the Plant Berry Facility and is more than the estimate for the Jewett, Texas site.

140 Figure 3 is from Trabucchi et al., *supra* note 185.

Insurance for CCS operations needs to consider all of the risks associated with more traditional industrial operations as well as the risks associated with long-term sequestration. Insurance markets for post sequestration and stabilization liability remain undeveloped. The possibility of open-ended liability—including the potential for a large payout—has discouraged investment in this area, as has the slow development of commercial scale CCS facilities. There may also be a mismatch between the real and perceived risk profile for long-term CCS, as reservoir pressures are anticipated to decrease over time, especially given that CO_2 is likely to react with brine and minerals in the rock to form bicarbonate and permanently trap a significant portion of the injected CO_2. This may, in turn, result in reliance on less accurate analogues for insurance model development.

Legislation at either the state or federal level that assumes long-term responsibility once injection has ceased and the CO_2 plume has stabilized may help in addressing these issues. This is what Congress has done for other industries, including, for example, for the nuclear power industry through the Price-Anderson Act. Otherwise, operators may need to explore more creative ways of developing insurance options.

4.3 FEDERAL ENVIRONMENTAL IMPACT REVIEW

The National Environmental Policy Act (NEPA)[141] has been described as the Magna Carta of environmental laws.[142] Notably, however, the law does not require the federal government to do anything substantive with respect to the environment. Rather, the statute requires the government to consider what impact different actions that it takes will have on the environment before taking those actions. The idea is that NEPA facilitates federal agencies making informed decisions because they consider the consequences of various alternative courses of action before proceeding. Indeed, NEPA does not require selection of the least damaging alternative, only that agencies take a hard look at tradeoffs before moving forward. Where an action involves approvals from multiple agencies, those agencies can combine their NEPA analyses. While several states have adopted state environmental policy acts that involve procedural mandates similar to NEPA, Utah is not one of those states.

4.3.1 The NEPA Process

NEPA requires that, prior to authorizing or undertaking any "major Federal action significantly affecting the quality of the human environment," the lead federal agency must analyze the likely impacts of that action on the environment. This often results in a detailed statement discussing the purpose and need for the proposed action, alternative means of satisfying the purpose and need, and the environmental impacts that are anticipated to result from each considered alternative, including an alternative of "no action."[143] Under NEPA, the "human environment" is defined broadly to include "the natural and physical environment and the relationship of people

[141] 42 U.S.C. §§ 4321–4370(h).
[142] DANIEL R. MANDELKER, NEPA LAW AND LITIGATION § 1:1 (2d ed. 2014).
[143] 42 U.S.C. § 4332(2)(C).

with that environment."[144] Major federal actions typically include the issuance of project permits, such as mineral leases on federal lands.

Not all federal actions have a "significant" impact, and the scope and intensity of impacts associated with the proposed action determine the level of analysis required. Where impacts are "significant" in both their context and intensity, an Environmental Impact Statement (EIS) is required. "Context" varies by project and is evaluated at multiple scales.[145] "Intensity" may reflect a wide array of factors, including but not limited to controversy surrounding the nature of the effects[146] and the degree to which the action may establish a precedent for future actions with significant effects.[147]

Where the significance of impact is uncertain, the lead federal agency may elect to prepare either an EIS or a less onerous Environmental Assessment (EA).[148] If the agency chooses the latter path and the EA shows that the impacts are significant, then the agency must prepare a full-fledged EIS. If, however, the EA shows that the impacts are not significant, the agency may issue a finding of no significant impact (FONSI) and a record of decision (ROD) on that determination.

Agencies are also authorized to promulgate regulations identifying categories of action that "do not individually or cumulatively have a significant effect on the human environment."[149] Agencies can then categorically exclude these actions from further NEPA review. However, even if a categorical exclusion (CE) has been established by rule, the existence of "extraordinary circumstances" may prevent its application.[150] Under Department of Energy regulations, certain small-scale CO_2 injection wells are categorically exempt from NEPA analysis.[151] CarbonSAFE, however, is likely to inject more than the 500,000-ton limit allowed under these regulations.

EISs are part of an iterative analytical decision making process that begins with publication of a Notice of Intent (NOI) to prepare an EIS.[152] The NOI kicks off a public scoping period in which the public is invited to submit comments about the proposal, the environmental issues the proposal raises, and potential alternative means of achieving the purpose of the proposed action.[153] Those comments help the lead federal agency identify issues, formulate alternatives, and collect or conduct necessary research. The reasonably foreseeable direct, indirect, and cumulative impacts anticipated to result from implementation of each alternative (including a "no action alternative") are then analyzed and disclosed in a Draft EIS (DEIS).[154] The DEIS is made available for public review and comment.[155] After considering public input, the lead federal agency releases a Final EIS (FEIS) that reflects public input on the agency's methods and

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[144] 40 C.F.R. § 1508.14.
[145] *Id.* § 1508.27(a).
[146] *Id.* § 1508.27(b)(4).
[147] *Id.* § 1508(b)(6).
[148] *Id.* § 1508.9.
[149] *Id.* § 1508.4.
[150] *Id.* § 1508.4.; *see e.g.*, 43 C.F.R. § 46.215 (2017) (listing extraordinary circumstances for BLM NEPA).
[151] 10 C.F.R. § Pt. 1021. Subpt. D App. B § B5.13 (2017).
[152] 40 C.F.R. § 1501.7.
[153] *Id.* § 1501.7(a).
[154] *Id.* §§ 1502.9(b), 1508.8.
[155] *Id.* § 1503.1(a)(4).

analysis.[156] Following a period in which the governor of the state within which the project occurs can comment on consistency with state requirements, the lead federal agency then issues a ROD stating the agency's decision and initiating a protest or appeals period.[157] Figure 62 details this process.

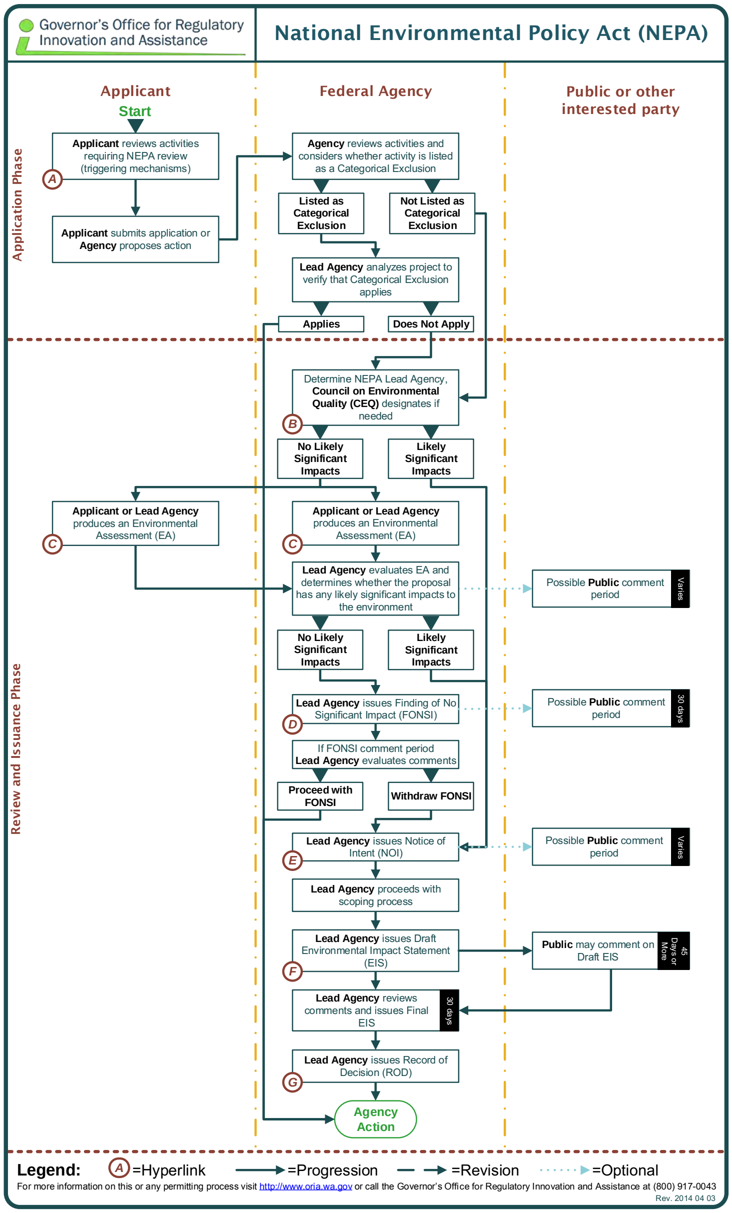

Figure 62. The NEPA Process[158]

[156] *Id.* § 1502.9(b).

[157] *Id.* § 1505.2.

[158] Schematic from Washington State, Governor's Office of Regulatory Innovation and Assistance https://www.oria.wa.gov/Portals/_oria/VersionedDocuments/Schematics_N-Z/National-Environmental-Policy-Act-Schematics.pdf.

Agencies are directed not to speculate when conducting their NEPA analysis, and therefore frequently choose to undertake a phased approach to NEPA implementation. The BLM, for example, may undertake a NEPA analysis as part of a planning-level decision to determine which lands are available for oil and gas development and which surface use stipulations will apply to those broad areas. Not all lands that are available for leasing will be of interest to industry, and the BLM may therefore need to review or update NEPA determinations in response to an expression of interest prior to leasing an individual parcel, if project-scale information was not considered at the multi-million-acre planning scale. The BLM may also need to conduct NEPA reviews on, for instance, the actual development of the well or well field if the viability of the field, the number of wells, likely field and pipeline layouts, or other associated impacts that were not discernable at the time of leasing. The federal agency, however, cannot segment one project into its component parts in order to reduce the level of analysis required under NEPA.[159]

4.3.2 NEPA Considerations for the CarbonSAFE Rocky Mountain Project

Multiple federal actions associated with the CarbonSAFE Project are likely to trigger NEPA review. If the CO_2 plume is anticipated to migrate into pore space that is under federal ownership or control, issuance of a federal lease to utilize the pore space will likely require NEPA analysis by the Bureau of Land Management. If the injection well compressors, pipelines, or other infrastructure are located on federal lands, obtaining rights to use these lands (leases or rights-of-way) will also require NEPA review. Issuance of federal permits that may be required by other laws may also require analysis under NEPA, including, potentially, for a CCS pipeline.[160] Finally, future funding of project implementation by the Department of Energy would also likely require NEPA analysis.[161]

Notably, Class VI injection well permitting, which is conducted by the EPA and occurs pursuant to the Safe Drinking Water Act, is likely exempt from NEPA review. Safe Drinking Water Act permitting is exempt from NEPA because the SDWA's requirements to consider the environment are "functional equivalents" of the impact statement process.[162]

With respect to the level of review that agencies are likely to employ, we believe that federal agencies are likely to conclude that an EIS is required for any possible CCS project like CarbonSAFE in light of the context and intensity of potential impacts. If a less rigorous level of analysis is available, permitting could move forward more expeditiously. A less rigorous approval process, however, may be more difficult to defend in the face of potential legal challenges. This is because, when challenging an EA, a party must show that impacts were either

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[159] Coalition on Sensible Transportation v. Dole, 826 F.2d 60, 68 (D.C. Cir. 1987) ("Agencies may not evade their responsibilities under NEPA by artificially dividing a major federal action into smaller components, each without 'significant' impact.").

[160] Most Clean Water Act permitting is exempt from NEPA, *see* 33 U.S.C. § 1371(c), as are most Clean Air Act permits, *see* 15 U.S.C. § 793(c)(1).

[161] Under DOE regulations, certain small-scale CO_2 injection wells are categorically exempt from NEPA analysis. 10 C.F.R. § Pt. 1021. Subpt. D App. B § B5.13.

[162] Western Nebraska Resource Council v. EPA, 943 F.2d 867, 871 (8th Cir. 1992).

inadequately considered or that impacts exceed the "significance" threshold. By contrast, in legal challenges to EISs, significance of impact is not an issue. Instead, the litigant must demonstrate that the agency failed to take the requisite "hard look" at potential impacts.[163] Proceeding as if an EIS is required therefore represents a conservative assumption for a project such as CarbonSAFE.

To expedite the NEPA process and reduce paperwork, federal agencies may integrate the NEPA review with other environmental reviews and consultation processes,[164] incorporate other NEPA documents by reference,[165] or "tiering from statements of broader scope to those of narrower scope, to eliminate repetitive discussions of the same issues."[166] Accordingly, CarbonSafe may be able to utilize the information contained in the Class VI injection well permit application to satisfy much of their NEPA obligation.

A recent review of EISs prepared for large oil and natural gas field development projects in the Intermountain West found that it takes an average of 4.4 years to complete an oil and gas field EIS, as measured from the NOI to ROD (the range was 1,057 to 2,556 days).[167] This represents a rough estimate of the time likely involved in obtaining NEPA approval for the CarbonSAFE Project, as the smaller geographic scope of the CarbonSAFE Project is likely to minimize the level of analysis required. However, as a first-of-kind project associated with a highly scrutinized industry and located proximate to areas that are of great interest to the environmental community, intense public scrutiny should be anticipated.

Notably, on September 1, 2017, the Secretary of the Interior issued an order to all agencies within the Department, including the Bureau of Land Management, directing them to complete their NEPA analyses within a one-year limit. The order also directs agencies to limit their EISs to 150 pages normally, or 300 pages for unusually complicated projects.[168]

Operators should not assume that the Department of the Interior will adhere to either time limits or page restrictions. Accelerating the NEPA process may impact the quality of the analysis and invite litigation. Rushing may, in short, prove to be counterproductive. We anticipate that the BLM will work hard to comply with the Secretarial Order without compromising document defensibility. The best way to do this is to frontload the NEPA analysis by completing requisite studies before publishing a NOI. This will result in delayed initiation of the formal NEPA process.

More importantly, when a federal agency is sued for failing to comply with NEPA's procedural requirements, the reviewing court will still ask whether the agency took the requisite "hard look" at the environmental consequences of the project and a reasonable range of alternatives.[169] This standard of review has not changed. The BLM has a strong incentive to ensure that EISs are defensible in court and is therefore likely to move text from the EIS into an appendix. This

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[163] Citizens to Preserve Overton Park, Inc. v. Volpe, 401 U.S. 402 (1971).

[164] 40 C.F.R. § 1500.4(k) (2017).

[165] *Id.* § 1500.4(j).

[166] *Id.* § 1500.4(i).

[167] John Ruple & Mark Capone, *NEPA—Substantive Effectiveness Under a Procedural Mandate: Assessment of Oil and Gas EISs in the Mountain West*, 7 G. WASH. J. ENERGY & ENVTL. L. 39, 43 (2016).

[168] U.S. Dep't of the Interior Secretarial Order 3355 (Sept. 1, 2017).

[169] Citizens to Preserve Overton Park, Inc. v. Volpe, 401 U.S. 402 (1971).

practice will change the formatting of NEPA documents but not reduce the overall analysis. The BLM likewise has a similar incentive to delay document completion in order to increase defensibility.

A final consideration involves the potential scope of review that would be required if the CCS operator intends to use only state or private pore space, but where that operator needs to acquire limited surface use rights for pipelines, monitoring wells, or other infrastructure. If such a question arises, the issue becomes the scope of the analysis required pursuant to NEPA. NEPA requires analysis of the direct, indirect, and cumulative effects of the various alternatives regardless of whether those impacts occur on federal land. "Direct" environmental effects are those "which are caused by the action and occur at the same time and place."[170] Indirect effects are those "which are caused by the action and are later in time or farther removed in distance, but are still reasonably foreseeable."[171] A cumulative impact is "the impact on the environment which results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions. . . . Cumulative impacts can result from individually minor but collectively significant actions taking place over a period of time."[172] Connected actions cannot be divided into their component parts in order to narrow or expedite the analysis.[173]

While NEPA compliance can be costly and time-consuming, it will likely be a necessary component of CarbonSAFE Rocky Mountain implementation. Possibly the best advice that we can provide regarding NEPA compliance is to coordinate closely with the BLM, be patient, and avoid the temptation to cut corners. A rushed NEPA analysis is more likely to contain errors or omissions that would cause a reviewing court to require a supplemental analysis. Any time saved by streamlining analysis on the front end will likely be more than consumed by litigation and revisions on the back end.[174]

4.3.3 The National Historic Preservation Act

Enacted in 1966, the National Historic Preservation Act[175] (NHPA) was intended, in part, to preserve historical and archaeological sites. Section 106 of the NHPA requires that federal agencies complete a review process for all federally funded and permitted projects that will impact sites listed on, or that are eligible for listing on, the National Register of Historic Places.[176] Under section 106, federal agencies must "take into account" the effect a project may have on historic properties. Section 106 allows interested parties an opportunity to comment on the potential impact that projects may have on significant archaeological or historic sites. Like NEPA, the NHPA is a procedural statute that does not require substantive protections. Rather, both statutes require federal agencies to "look before they leap."

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[170] 40 C.F.R. § 1508.8(a).

[171] *Id.* § 1508.8(b).

[172] *Id.* § 1508.7.

[173] *Id.* § 1508.25(a)(1).

[174] *See* John Ruple & Mark Capone, *NEPA, FLPMA, and Impact Reduction: An Empirical Assessment of BLM Resource Management Planning and NEPA in the Mountain West*, 46 ENVTL. L. 952 (2017).

[175] 16 U.S.C. §§ 470 *et seq.*

[176] *Id.* § 470f.

Any federal agency whose project, funding, or permit may affect a historic property that is either listed or eligible for inclusion in the National Register of Historic Places must consider project effects and seek to avoid, minimize, or mitigate any adverse effects on historic properties. NHPA compliance will require early consultation with BLM archaeologists and the State Historic Preservation Officer. These individuals will be able to search agency records and identify known cultural and historic sites. Surveys and tribal consultation may be required to determine whether additional cultural or historic sites are found within the project area and, if so, whether these sites are potentially eligible for inclusion on the National Register of Historic Places.

Of note for the CarbonSAFE Rocky Mountain project, oil and natural gas lease sales in the region have been challenged and sometimes deferred because of possible impacts to petroglyphs and pictographs that are known to exist near the San Rafael Swell. These sites, which are almost certainly eligible for inclusion on the National Register of Historic Places, have not been the subject of comprehensive surveys and are therefore not well documented. While the project at hand has a limited geographic footprint and is therefore less likely to impact sites across a broad area, the project team should still consult with the BLM and Utah State Historic Preservation Officer to identify archaeological sites, historic mining properties, homesteads, or other sites than may warrant special attention.

4.3.4 Lessons Learned from Permitting Other CCS Facilities

We reviewed permitting documents for other CCS facilities in order to identify lessons that could be learned from those experiences, as detailed above. While the CarbonSAFE Rocky Mountain project will be subject to many of the same procedural requirements, factual differences between the project at hand and prior CCS facilities need to be acknowledged when considering the experience at other CCS facilities. Nonetheless, the experience of the other projects is useful when appraising the path forward for a potential CarbonSAFE Rocky Mountain project.

NRG Energy (W.A. Parish Post Combustion Project)

NRG Energy's proposed W.A. Parish PCCS Project involved construction of a CO_2 capture facility at NRG's 4,880-acre W.A. Parish Plant in rural Fort Bend County, Texas (sometimes also referred to as the Petra Nova Project). The capture facility would use an amine-based absorption technology to capture at least 90% of the CO_2 from a 250-megawatt equivalent portion of the flue gas exhaust from Unit 8 at the plant. The project would be designed to capture approximately 1.6 million tons of CO_2 per year, and the captured CO_2 would be compressed and transported via a new, 81-mile-long, 12-inch-diameter underground pipeline to the existing West Ranch oil field in Jackson County, Texas. There, the CO_2 would be used for enhanced oil recovery and ultimately sequestered in geologic formations approximately 5,000 to 6,300 feet below the ground surface.

The DOE completed an EIS for the W.A. Parish Project, addressing the following issues: air quality and climate, greenhouse gas emissions, geology, physiography and soils, surface waters, ground water, floodplains, wetlands, biological resources, cultural resources, land use, aesthetics, traffic, transportation, noise, materials and waste management, human health and safety, utilities, community services, socioeconomics, and environmental justice. For purposes of the EIS, the DOE assumed that the project would continue for twenty years. The DOE was required to conduct a NEPA analysis because the project involved DOE funding.

The W.A. Parish Project did not generate significant controversy; there were just four comments on the Draft EIS. Of the four comments received, three came from government agencies, and one was from a member of the general public. Comments from the public focused on air quality impacts associated with the continued combustion of coal and how conversion to a natural gas-fired facility would help reduce both VOC and NOx emissions. The EPA was concerned about damage to navigable waters and jurisdictional wetlands. The DOE asserted that all navigable water would be identified and that any wetland permanently impacted would be mitigated. The FWS was concerned with impacts to listed species under the ESA. The DOE amended the EIS to ensure that more migrating birds would not be impacted during pipeline construction. The Texas Parks and Wildlife Department echoed the FWS and the DOE ensured their concerns were addressed. Pore space ownership was not as issue, as CO_2 was injected into an existing field for EOR.

ADM

The ADM project was considered a "federal action" and therefore subject to NEPA because of DOE funding. The NEPA analysis considered only two alternatives, the proposed action and a no action alternative under which the DOE would not contribute any funds. EPA permitting documents do not mention public comments received in response to the ADM proposal. The narrow range of alternatives and absence of a discussion of public comments likely indicate that the project received little public scrutiny. While the reasons for limited public interest are difficult to identify, the setting and short duration of the project were likely contributing factors. Notably, ADM appears to own the pore space into which the CO_2 is injected, thus limiting potential impacts to public lands and removing a major concern that is likely to face the CarbonSAFE project.

As noted in the earlier discussion of SDWA permitting for the ADM project, the EPA did not address pore space ownership as part of its analysis. It also appears that no claim of federal pore space ownership was implicated by the ADM project. CarbonSAFE Rocky Mountain is therefore distinguishable from the ADM permit because the BLM will need to complete a NEPA review before granting rights to utilize the federal surface or sub-surface, and this analysis will necessarily consider pore space ownership. This NEPA analysis will be independent of the EPA's NEPA analysis for the Class VI injection permit. Proximity to the San Rafael Swell is also likely to attract a level of public attention that was absent from the ADM project.

With respect to the ADM project, the EPA also disclaimed any need to consult with the Fish and Wildlife Service regarding impacts to species protected pursuant to the Endangered Species Act. The EPA stated that they found there was no jeopardy to listed species or critical habitat, thus ending the inquiry. Further, EPA disclaimed any need for NEPA review because the action was "administrative in nature." Again, CarbonSAFE should not assume such expedient treatment of its project. While the EPA may consider impacts to wildlife to be beyond the scope of their permitting analysis, the likely use of federal surface or sub-surface for either infrastructure or sequestration will necessitate BLM involvement, and as issuance or a right-of-way or permit to utilize federal lands could represent an irretrievable commitment of resources, the BLM will almost certainly need to consider wildlife impacts before rendering a decision.

4.4 ADDITIONAL LEGAL AND REGULATORY CONSIDERATIONS

The above analysis highlights the key legal issues that tend to be focused on with respect to CCS projects. However, there are several other issues that may arise, and that would need to be addressed depending on the particular facts of the project. Those facts should come into clearer focus should the CarbonSAFE Rocky Mountain project proceed beyond Phase I.

4.4.1 Public Utility Regulation

One key regulatory approval that the CarbonSAFE Rocky Mountain project would have to obtain is a determination that the cost imposed by the project on electricity customers is not too great. This involves six determinations, not one. Rocky Mountain Power is a subsidiary of PacifiCorp. In turn, PacifiCorp allocates portions of is broad generation portfolio among its various utility subsidiaries serving customers in six states: California, Idaho, Oregon, Utah, Washington, and Wyoming. Unless PacifiCorp chose to alter this allocation, conceivably the public service commission in each of those states would need to pass on the cost impacts of the CarbonSAFE project at some point.

At one level, this form of regulation would not appear to pose too high of a burden for the CarbonSAFE project. Although regulatory approval eventually would be needed, utility law generally does not require electricity providers to file a new rate case every time they incur some new cost. Rather, they must only do so when they seek a general rate increase or change.[177] So, the CarbonSAFE project theoretically could be operational before such a rate approval were sought.

However, two caveats limit how much leeway the proponents of the CarbonSAFE project might actually enjoy. First, public utility commissions typically can start their own investigations of a utility, if they see fit. Thus, if the CarbonSAFE project raised concerns for any of these states' public service commissions, regulatory oversight could arrive more quickly than planned. Second, when a rate case is brought, even by the utility itself, the utility must justify the cost as both "just and reasonable"—that is, not too expensive—as well as "prudent"—that is, an economically efficient investment that a reasonable or prudent manager of the company would make.[178]

Under this substantive standard, the two biggest hurdles to the CarbonSAFE project likely would be economic and policy-based. The economic obstacle is obvious and relates back to the cost barrier to commercial-scale deployment that CCS technology faces. Since the objective of utility regulation is to ensure that companies only incur necessary (and economically efficient) costs in providing service, there is a risk that parties would argue the comparatively high cost of CCS is neither. Of course, were some kind of greenhouse gas emission limit placed on PacifiCorp or Rocky Mountain Power, this might be easier to show, but the receding nature of federal regulation in that context and the absence of it in many state contexts renders that argument more difficult to make. Moreover, even with climate regulation of the electricity sector in place, proponents of the CarbonSAFE project arguably would need to either show that CCS technology

[177] *See, e.g.*, UTAH CODE § 54-7-12.
[178] *See, e.g.*, UTAH CODE § 54-3-1.

is as cost-effective as other ways of mitigating climate emissions (such as solar or wind) or point to a CCS-specific mandate of some kind. This may be difficult.

From a policy-based perspective, the CarbonSAFE project also could face challenges. Many of the states from which PacifiCorp would need regulatory approvals have renewable energy requirements for the electricity sector in place.[179] This could raise questions about why the CarbonSAFE project is appropriate in light of those statutory mandates. Further, two of the states—California and Washington—have climate regulations in place that affect the electricity sector,[180] and one of the states—Oregon—has an outright ban on coal generation beginning in 2030.[181] Again, PacifiCorp potentially could eliminate these concerns by reallocating how it operates its generation fleet, but in the absence of that step, this state-level regulation would appear to create challenges for the CarbonSAFE project, if the electricity generation associated with it is allocated to any of these states. These are concerns for which the project team would want to have a plan before proceeding to implementation of the CarbonSAFE Rocky Mountain project.

4.4.2 Brine Disposal

The Navajo sandstone into which the CarbonSAFE Rocky Mountain would inject CO_2 contains saline brine. CO_2 will react with brine to form carbonate, but some brine may be displaced by injected CO_2. The extent to which brine would be displaced was uncertain at the time this report was written. Displacement of brine must be considered as noted in SDWA permitting and tort liability discussions, above. If brine must be extracted to increase storage capacity, extracted brine will need to be dealt with, possibly by using brine for EOR. Use of brine for EOR would trigger the SDWA's UIC class II permitting requirements.

If brine cannot be utilized for EOR, it will need to be disposed of in accordance with applicable environmental laws and regulations. In that case, permits would need to be obtained in accordance with the Clean Water Act and other applicable requirements before brine could be discharged into a receiving water or via land application. Any water treatment that results in sludge or contaminated filter materials could trigger hazardous waste disposal permitting requirements.

Alternatively, brine could be disposed of in evaporative ponds, though this could pose additional regulatory challenges, and highly concentrated minerals would require additional processing and disposal. Portions of Eastern Utah suffer from elevated ozone levels, which have been attributed, in part, to oil and gas development activities. Evaporation of oil and gas product water has been identified as a contributor to elevated ozone levels because product water often contains volatile organic compounds (VOCs). VOCs evaporate readily and are subject to atmospheric photochemical reactions that produce ground-level ozone. Any brine that is removed from the storage reservoir may therefore need to be treated to remove VOCs, if VOCs are present in the

[179] *See* CAL. PUB. UTIL. CODE § 399.11; OR. REV. STAT. § 469A.052; UTAH CODE § 10-19-201; WASH. REV. CODE § 19.285.040.

[180] *See, e.g.*, CAL. HEALTH & SAFETY § 38566; Code CAL. PUB. UTIL. § 8341; WASH. REV. CODE § 80.80.040.

[181] *See* OR. REV. STAT. § 757.518.

brine, before evaporation could proceed. Similar concerns could arise if the brine contains trace quantities of radionuclides, or hazardous chemical elements such as arsenic.

Surface disposal could also raise environmental concerns if brine is stored in evaporation ponds that attract wildlife. Hydrocarbons in the brine could coat the wings of migratory birds that are attracted to the water surface. Similarly, salts or other minerals that are toxic to migratory birds can cause avian mortality. Mortality that is attributable to surface disposal operations could trigger liability under the Migratory Bird Treaty Act, the Bald and Gold Eagle Protection Act, the Endangered Species Act, or other state and federal statutes.

4.5 PUBLIC OUTREACH & STAKEHOLDER ASSESSMENT

The Rocky Mountain CarbonSAFE team identified stakeholders with potential interests to a potential CO_2 capture/storage complex project or area, identified potential benefits and concerns for these stakeholders, and began to develop strategies to maximize benefits, mitigate identified concerns, and facilitate stakeholder acceptance. The team identified 48 principal stakeholders (see Appendix M), including government officials and agencies, environmental health directors from local health departments, regulators, business interests, local interested citizens, local and regional environmental groups, national environmental groups, and educators.

The team developed and distributed an outreach flyer designed to provide basic information about the project; developed an informative public website (www.carbonsafe.rocks); and published a non-technical article in the September 2017 issue of the Utah Geological Survey's Survey Notes, detailing the project and how it benefits Utah (https://geology.utah.gov/map-pub/survey-notes/energy-news/carbonsafe/).

On October 10th, 2017 the team held a public town hall discussion to answer stakeholder questions and address concerns. The team emailed all identified stakeholders an invitation which included the project's informational flyer and webpage link.

The team consulted with Phase 2 Productions, a local studio with experience filming and producing energy sector videos. Phase 2 Productions provided general ideas on how short videos can be used to promote the project and provided a specific proposal to produce a series of short, three- to four-minute videos highlighting the project and its potential benefits.

5.0 Scenario Development of Commercial-scale CCS Complex

5.1 SCENARIO DEVELOPMENT & DATA

Scenarios of interest span from small-scale scenarios of single sources and single reservoirs, to larger-scale scenarios integrating EOR with consideration given to the long-term performance of a proposed CCS complex in a carbon-constrained world. The scenarios developed for the Rocky Mountain CarbonSAFE project fall into three categories:

1. Core Scenarios: Scenarios consisting of single sources and single reservoirs covering the Hunter and Huntington power plants and Buzzard's Bench and Drunkard's Wash saline aquifers.
2. EOR Scenarios: Scenarios consisting of capturing from multiple sources (primarily the Hunter and Huntington power plants) and injecting into the Uintah Basin oil fields.
3. Cortez Pipeline Scenarios: Scenarios consisting of capturing from multiple sources (primarily the Hunter and Huntington power plants) and transporting to the Cortez pipeline terminus at McElmo Dome in southwestern Colorado.

Costs and capacities associated with the different reservoir types are detailed in Table 21 and for the different source types in Table 22. Capture costs for the different source types were taken from current literature (Bains et al., 2017; Rubin et al., 2015).

Table 21. Storage costs associated with the different reservoir types.

Reservoir Type	Capacity (MtCO2)	Opening Cost ($M)	Well Cost ($M)	Injection Cost ($/tCO2)
Saline	581	7.31	3.85	-
*Buzzards	*201			*3.15
**Drunkards	**380			**3.18
EOR	1023	0	0	-30
Cortez	24	0	0	-30

Table 22. Capture costs associated with the different source types.

Source Type	Capacity (MtCO2/yr)	Capture Cost ($/tCO2)
Electricity (Coal)	28.7	46
*Hunter	*8.8	
**Huntington	**6.2	
Electricity (Gas)	2	74
Petroleum	1.6	67.5
Cement	1	34
Iron/Steel	0.1	33
Chemical	0.1	14

5.1.1 Core Scenarios

The core scenarios developed center on capturing partial emissions from either the Hunter or Huntington power plants and injecting into saline aquifers below Buzzard's Bench or Drunkard's Wash. Primary and auxiliary capture/storage configurations for the core scenarios were determined by the project team and are detailed in Table 23.

Table 23. Ranking of capture/storage scenarios from most desirable (#1) to least (#4).

Column1	Buzzard's Bench	Drunkard's Wash
Hunter	#1	#2
Huntington	#4	#3

Injection well locations in Buzzard's Bench and Drunkard's Wash were determined by the project team after surveying the existing well pads in the region. The storage capacity of the saline aquifers at Buzzard's Bench and Drunkard's Wash were estimated by the project team to be 201 $MtCO_2$ (Buzzard's Bench) and 380 $MtCO_2$ (Drunkard's Wash). The target capture amount considered for these core scenarios is the minimum DOE requirement of 50 $MtCO_2$ over a 30-year project timeline.

5.1.2 EOR Scenarios

EOR scenarios involve capturing CO_2 from sources and injecting it into the Uintah Basin oil fields in the most cost-effective manner. For each scenario, the Hunter and Huntington power plants emissions are all captured before other sources are utilized to better support the core aim of the Rocky Mountain CarbonSAFE project. EOR reservoir locations were taken to be the centroids of the individual Uintah oil fields from NatCarb (www.natcarb.netl.doe.gov). The target capture amounts considered for these scenarios are:

1. Minimum DOE requirement of 1.7 $MtCO_2$/yr captured.
2. Full Hunter and Huntington plant emissions of 15 $MtCO_2$/yr captured.
3. All available source emissions of 33.5 $MtCO_2$/yr captured.
4. Intermediate capture values of 20 $MtCO_2$/yr, 25 $MtCO_2$/yr, and 30 $MtCO_2$/yr.

5.1.3 Cortez Pipeline Scenarios

To explore the possibility of offsetting CO_2 mined from McElmo Dome with anthropogenic CO_2, scenarios were constructed that transport captured CO_2 to the Cortez pipeline terminus in south western Colorado. The scenarios involved capturing from just the Hunter and Huntington power plants and from all available sources. Costs associated with transferring (not including to cost to transport CO_2) CO_2 to the Cortez pipeline are detailed in Table 22. The target capture amounts considered for these scenarios are:

1. Minimum DOE requirement of 1.7 $MtCO_2$/yr captured from Hunter or Huntington.
2. Full Hunter and Huntington plant emissions of 15 $MtCO_2$/yr captured.
3. Full capacity of Cortez pipeline (24 $MtCO_2$/yr) captured.

5.2 SCENARIO ANALYSIS TOOL

SimCCS is an optimization model for integrated CCS system design, originally introduced in 2009, and recently modernized in a complete, ground-up redesign that allows collaboration on the design of CCS infrastructure networks across CCS research, industrial, policy, and public communities (Middleton and Bielicki, 2009; Yaw et al., 2018). *SimCCS* utilizes user-provided data for the CO_2 sources (capture capacities and costs), sinks (geologic parameters), and CO_2 transportation information (weighted-cost surface of the deployment region). *SimCCS* creates candidate transportation routes using novel network generation algorithms and formalizes an optimization problem that determines the most cost-effective CCS system design. This optimization problem is then solved either locally through user-provided third-party software on their local machine or through a high-performance computing (HPC) platform hosted by Indiana University. Integration with HPC resources allows for solutions to problems of unprecedented size (e.g., national-scale domains the size of the United States or China) and complexity (e.g., massive ensembles incorporating uncertainty within the integrated CCS system). Finally, *SimCCS* employs an open-access GIS framework to enable analysis and visualization capabilities.

The Rocky Mountain CarbonSAFE project used *SimCCS* to characterize the CCS infrastructure designs for the various scenarios and quantify their costs. *SimCCS* was parameterized with relevant regional source and sink data, as well as a weighted-cost surface of the greater Utah region to accurately reflect pipeline routes and their associated costs. For each scenario considered, a set of possible pipeline routes, called the *candidate pipeline network*, was constructed to feed the optimization model. Final pipeline routes for a given scenario are generated using a four-step process: First, the geographic area is rasterized into a weighted-cost surface that multiplies the base cost of building a CO_2 pipeline across a uniform surface to match the corresponding geography of the real world. This base cost is established from published values for natural gas pipelines. Second, a set of potential origin-destination paths between all source/sink location pairs is calculated using a modified Dijkstra shortest-path algorithm on the weighted-cost surface. Third, a subset of these paths is selected as a candidate network by selecting edges that connect node pairs; these pairs are defined by a Delaunay triangulation of all source/sink locations. And fourth, final routes are selected by a Mixed Integer Linear Program (MILP) that aims to minimize cost while connecting source/sink locations in a way to ensure a target CO_2 capture amount is met. In the last step, final pipeline routes are selected from the candidate network. This is done in conjunction with selecting which sources and sinks to open and how much to capture and inject into each location. An MILP is formulated that minimizes capture, transport, and storage costs while ensuring that enough CO_2 is captured and injected so as to meet project targets. From this optimization problem, a completed CCS infrastructure design is produced, that includes the necessary pipelines (of the appropriate size) to transport CO_2 from its capture location to its storage location.

5.3 SCENARIO ECONOMIC ANALYSIS

For each scenario illustrated in the previous section, candidate pipeline networks were built with *SimCCS* using the greater Utah weighted-cost surface. Optimization models were constructed with project lengths of 30 years and target capture amounts specific to the scenario. The models were solved using IBM's CPLEX software package. The costs associated with each scenario are summarized in Table 24. Scenario-specific pipeline routes produced by the optimization model are available to the project team. The infrastructure designs produced by *SimCCS* for all the scenarios are presented in Figure 63 for the core scenarios, Figure 64 for the EOR scenarios, and Figure 65 for the Cortez pipeline scenarios.

Table 24. Scenario cost comparisons.

Scenario	Capture Target (MtCO2)	Cost ($M/yr)	Capture Cost ($M/yr)	Transport Cost ($M/yr)	Storage Cost ($M/yr)	Unit Cost ($/tCO2)
Hunter-Buzzard's	51	85.68	78.2	0.84	6.64	1.68
Hunter-Drunkard's	51	87.33	78.2	2.44	6.69	1.71
Huntington-Buzzard's	51	86.14	78.2	1.3	6.64	1.69
Huntington-Drunkard's	51	86.66	78.2	1.76	6.69	1.7
EOR-1.7/yr	51	28.68	78.2	1.48	-51	0.56
EOR-15/yr	450	261.93	690	21.93	-450	0.58
EOR-20/yr	600	361.58	920	41.58	-600	0.6
EOR-25/yr	750	445.31	1150	45.31	-750	0.59
EOR-30/yr	900	540.16	1374.45	65.71	-900	0.6
EOR-33.5/yr	1005	904.02	1814.9	94.12	-1005	0.9
Cortez-1.7/yr	51	41.77	78.2	14.57	-51	0.82
Cortez-15/yr	453	276.17	694.6	34.57	-453	0.61
Cortez-24/yr	720	437.56	1088.8	68.76	-720	0.61

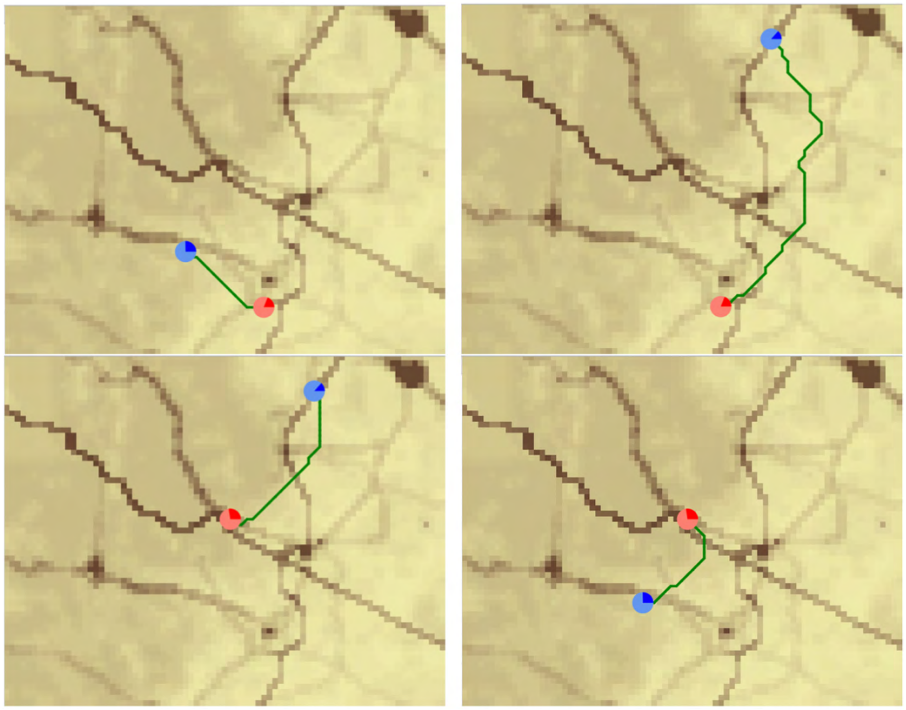

Figure 63. Infrastructure designs for the core scenarios: Hunter and Buzzard's Bench (top left), Hunter and Drunkard's (top right), Huntington and Drunkard's (bottom left), and Huntington and Buzzard's (bottom right).

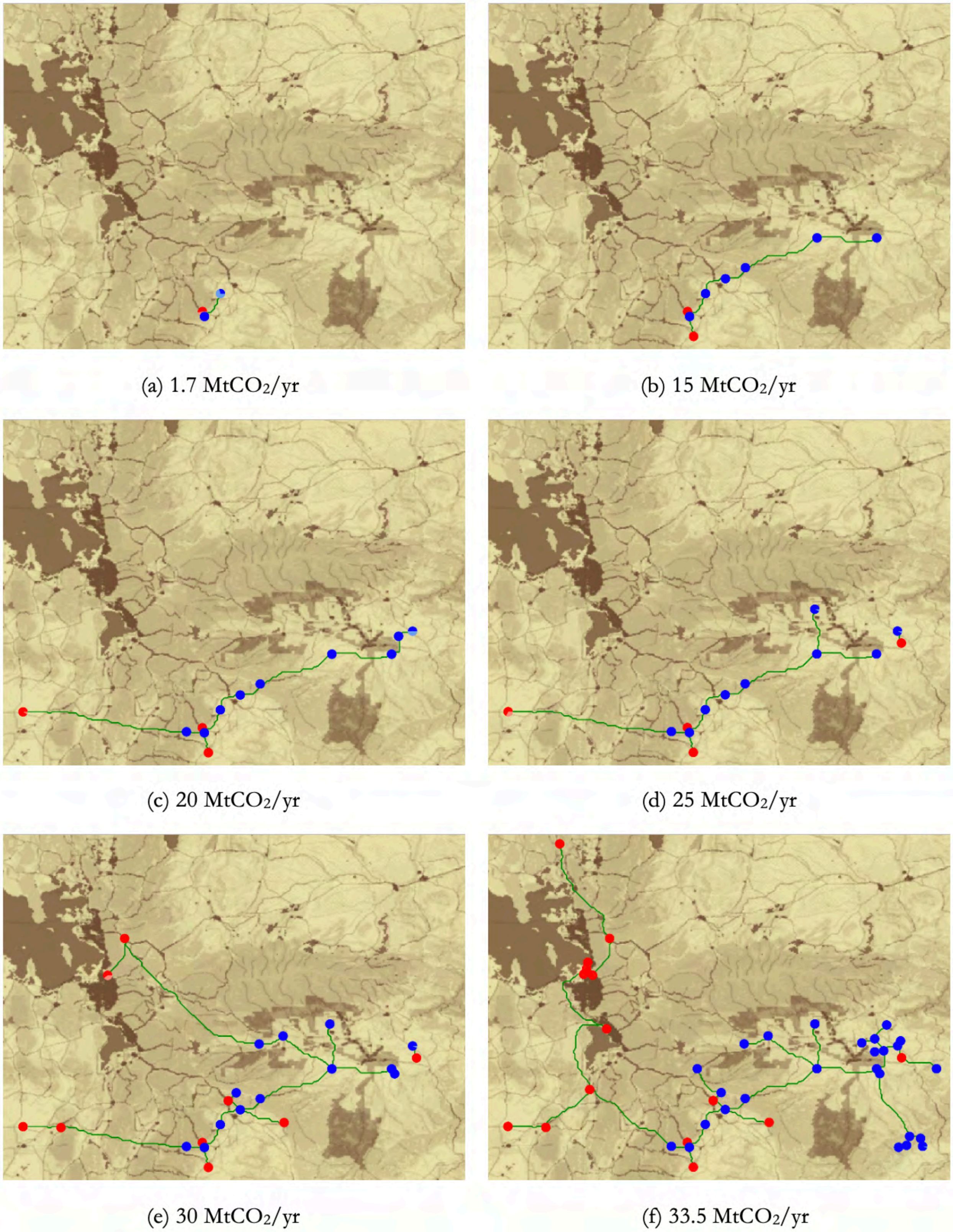

Figure 64. Infrastructure designs for the EOR scenarios with varying target capture amounts from 1.7 *$MtCO_2$*/yr (DOE minimum) to 33.5 $MtCO_2$/yr (capturing maximum amounts from all available sources).

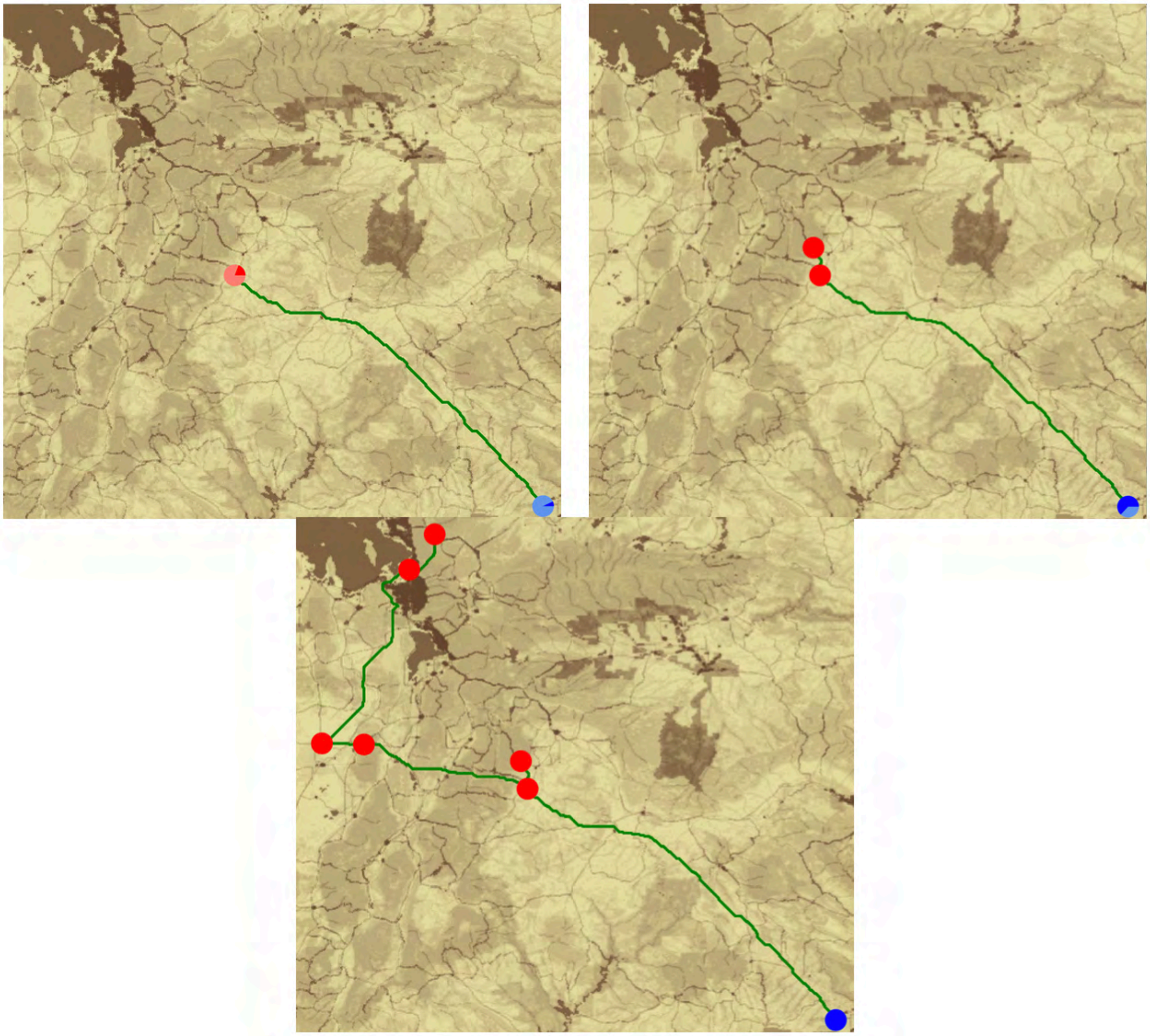

Figure 65. Infrastructure designs for the Cortez pipeline scenarios: 1.7 $MtCO_2$/yr captured from Hunter (top left), 15 $MtCO_2$/yr captured from Hunter and Huntington (top right), and 24 $MtCO_2$/yr (Cortez pipeline capacity) captured from the most cost-effective sources (bottom).

5.4 CONCLUSION

This report documents the motivation, development, and analysis of a wide range of scenarios for a commercial-scale CCS complex in the Rocky Mountains. Cost analysis supports the primary core scenario developed by the Rocky Mountain CarbonSAFE of capturing CO_2 from the Hunter power plant and transporting and injecting it into saline aquifers below Buzzard's Bench. However, larger-scale infrastructure deployments that include economic offsets may result in lower unit cost per ton of CO_2 stored. Selling CO_2 to oil fields in the Uintah Basin for EOR applications could result in a cost savings of up for 67% per ton of CO_2. Offsetting CO_2 mined from McElmo Dome also provides an enticing economic opportunity with near the cost savings as Uintah EOR. CO_2 from all sources considered accounted for 98% of the EOR capacity, so none of the scenarios benefitted from utilizing available EOR before spilling excess captured CO_2 to the saline aquifers. However, recent 45Q tax incentives could change the economic tradeoff between shipping CO_2 to a remote oil field versus injecting into nearby saline storage. Finally, the EOR and Cortez pipeline scenarios all show a clear network of trunk pipelines being constructed in the smaller-capture scenarios that increase in utilization for the larger-capture scenarios. This suggests that this region would be a strong candidate for staged deployments, where the pipeline infrastructure is initially overbuilt in anticipation of future capture sites coming online at a later date which has been shown to add resiliency to a project (Middleton and Yaw, 2018).

7.0 References

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Appendix A

CO2 CAPTURE TECHNO ECONOMIC ASSESSMENT

University of Utah
PacifiCorp's Hunter Station Unit 3

CO_2 Capture Techno Economic Assessment

FINAL Revision 0

December 15, 2017
Project No. 13644-001

Prepared by

Sargent & Lundy LLC

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Executive Summary

The University of Utah is evaluating the technical and commercial feasibility of carbon dioxide (CO_2) capture with sequestration (CCS) in a geologic formation adjacent to PacifiCorp's Hunter Plant. This is being conducted as part of the University's participation in a USDOE funded Phase 1 CO_2 Capture and Sequestration study (USDOE FOA DE-FE0029280). As part of this overall effort, the University engaged Sargent & Lundy LLC (S&L) to evaluate the feasibility and overall cost of retrofitting Hunter Unit 3 with a CCS system.

This study effort includes evaluation of multiple capture levels using a commercially available amine-based system as the basis for the capture technology. As part of the project, S&L evaluated three different levels of CO_2 capture on Hunter 3:

1. 65% capture, targeting no less than 1.84 million tons per year;
2. 90% capture, treating 100% of flue gas; and
3. Equivalent capture required (~48%) to achieve CO_2 emissions rate consistent with New Source Performance Standards (NSPS) for greenhouse gases for a natural gas-fired combined cycle plant (i.e. 1,000 lbs/MWh, gross)

This study effort includes evaluation of a commercially available amine-based system as the basis for the capture technology. S&L considers commercially available processes to be those that have been demonstrated during slipstream tests or have been implemented on permanent installations treating a quantity of flue gas that is at least equivalent to 5 MWe. Amine solvent-based technology has recently established itself as a viable technology for CO_2 capture. The commercial technology that was evaluated was MHI's KM-CR Process® with KS-1™ solvent.

As part of the TEA, the major balance of plant (BOP) impacts have been identified and quantified, including loss of power generation due to both the auxiliary power load and the required process steam to be supplied from the base unit. Other BOP impacts are identified, including cooling and process water consumption, waste water generation rates, and solid waste generation rates. S&L also developed material balances and general arrangement drawings that reflect the integration of the CO_2 capture system with the base facility.

A full scale capture system (Case 2: 90% capture) served as the basis for development of heat balances, mass balances, process flow diagrams, general arrangements, equipment sizing, and capital costs. The full scale system inputs were adjusted for the two other capture facility design sizes: Case 1: 65% and Case 3: 1,000 lb CO_2/MWh_g.

Overall, the project is technically feasible PacifiCorp's Hunter Unit 3. Process steam will be provided by the base unit and extracted at the IP/LP crossover without disrupting the performance of the LP turbine; however, this will cause a unit derate by limiting the total amount of megawatts the turbines can produce. Other utilities provided by the base plant include process water makeup from the existing demineralized water system, cooling tower makeup water from the on-site storage basin, and auxiliary power from the existing auxiliary power transformer. Flue gas will be routed to the CO_2 capture island downstream of the WFGD system, which reduces the amount of acid gas polishing that is required in the pre-scrubber. The CO_2 process is expected to generate pipeline quality liquid CO_2 for transportation to a storage field or an EOR facility.

The total capital cost is based on the conceptual design of the CO_2 capture system defined in this study. S&L scaled and adapted cost information for the MHI technology to develop the cost for the CO_2 capture process equipment for the Hunter application. S&L supplemented the CO_2 process equipment cost with a study-level BOP cost estimate based on S&L's experience within the utility industry, particularly experience on other CO_2 capture projects, projects at Hunter, and general AQCS projects.

Similarly, an estimate of the annual O&M cost was developed based on the conceptual design defined in this study, using cost information for the MHI technology and other industry experience.

The results of this evaluation including the total overnight capital cost, annual O&M cost, and cost of electricity (COE) are included in Table ES-1. Due to economies of scale, the overall cost of capture ($/ton of CO_2 removed) is less at larger capture rates. Depending on the project size selected, the estimated cost of capture at Hunter 3 ranges from $50-74/ton CO_2 removed.

Table ES-1: Evaluated Cost of CO_2 Capture Systems

Description	**Units**	**Case 1 (65% Capture)**	**Case 2 (90% Capture)**	**Case 3 (1,000 lb/MWh$_g$)**
Total Capital Cost	$	518,136,300	666,222,700	421,935,100
CCF		0.1243	0.1243	0.1243
Annualized Capital Cost	$/yr	64,404,400	82,811,500	52,446,600
Annual O&M Cost	$/yr	66,268,000	85,840,000	52,697,000
Total Annual Cost	$/yr	130,672,400	149,079,500	118,714,600
Annual CO_2 Captured	tons	2,158,460	2,991,500	1,595,240
Cost of Capture w/ TS&M	**$/ton**	61	50	74

1 Introduction

The University of Utah is evaluating the technical and commercial feasibility of carbon dioxide (CO_2) capture with sequestration (CCS) in a geologic formation adjacent to PacifiCorp's Hunter Plant. This is being conducted as part of the University's participation in a USDOE funded Phase 1 CO_2 Capture and Sequestration study (USDOE FOA DE-FE0029280). As part of this overall effort, the University engaged Sargent & Lundy LLC (S&L) to evaluate the feasibility and overall cost of retrofitting an existing power plant with a CCS system.

The evaluation includes development of expected performance, environmental impacts and capital and operating costs associated with implementing CCS on Unit 3 at the Hunter Plant.

Hunter Station is located in Castle Dale, Utah. Unit 3 is a 511 MWg boiler that burns low-sulfur, subbituminous coal. Unit 3 is equipped with low-NO_x burner technology and over fire air for NO_x mitigation, a baghouse for particulate matter removal, and wet flue gas desulfurization (WFGD) for SO_2 control.

This study effort includes evaluation of multiple capture levels using a commercially available amine-based system as the basis for the capture technology. Amine solvent-based technology has recently established itself as a viable technology for CO_2 capture. This technology is applicable to the fossil power industry, especially for high CO_2 producing coal-fired plants. However, there have been very few full scale CO_2 capture projects which have been implemented in the industry. Commercial scale CO_2 capture is still a relatively new technology and, therefore, still has some obstacles associated with minimal experience designing, building, and operating these facilities in full scale.

1.1 Key Project Goals

The University of Utah requested that S&L perform a Techno-Economic Assessment (TEA) of the commercially available amine-based CO_2 capture technologies. The TEA is intended to determine the technical feasibility and economic impacts of implementing CO_2 capture on Unit 3 at Hunter Station (Hunter 3). As part of the project, S&L will evaluate three different levels of CO_2 capture on Hunter 3:

1. 65% capture, targeting no less than 1.84 million tons per year;
2. 90% capture, treating 100% of flue gas; and
3. Equivalent capture required (~48%) to achieve CO_2 emissions rate consistent with New Source Performance Standards (NSPS) for greenhouse gases for a natural gas-fired combined cycle plant (i.e. 1,000 lbs/MWh, gross)

As part of the TEA, the major balance of plant (BOP) impacts have been identified and quantified, including loss of power generation due to both the auxiliary power load and the required process steam to be supplied from the base unit. Other BOP impacts are identified, including cooling and process water consumption, waste water generation rates, and solid waste generation rates.

1.2 Scope and Approach

The first step of the techno-economic assessment (TEA) was to establish the design criteria to be used as the basis for the CO_2 capture facility. Site-specific design criteria and conditions for Hunter 3 were developed using process information from the station. Process assumptions were based on previous S&L projects for the Hunter Station.

The commercial technology that was evaluated was MHI's KM-CR Process® with KS-1™ solvent. S&L considers commercially available processes to be those that have been demonstrated during slipstream tests or have been implemented on permanent installations treating a quantity of flue gas that is at least equivalent to 5 MWe. The MHI technology is a leader in CO_2 capture, with the largest installation on a coal-fired power plant in the world.

The design of the CO_2 capture system for this TEA reflects the MHI-specific process, to the greatest degree possible. As input to the TEA, S&L used a composite of budgetary pricing and process information for the MHI system supplemented with S&L's industry experience.

A conceptual design of the CO_2 capture system was developed using site-specific design criteria for Hunter Unit 3, supplemental information derived from the MHI technology and S&L's experience. As part of the conceptual design, S&L identified the major BOP impacts associated with the slipstream CO_2 capture facility, based on the utility requirements of the process. S&L also developed material balances and general arrangement drawings that reflect the integration of the CO_2 capture system with the base facility. The mass balances and process flow diagrams are included in Attachment A.

The total capital cost is based on the conceptual design of the CO_2 capture system defined in this study. S&L scaled and adapted cost information for the MHI technology to develop the cost for the CO_2 capture process equipment for the Hunter application. S&L supplemented the CO_2 process equipment cost with a study-level BOP cost estimate based on S&L's experience within the utility industry, particularly experience on other CO_2 capture projects, projects at Hunter, and general AQCS projects.

Similarly, an estimate of the annual O&M cost was developed based on the conceptual design defined in this study, using cost information for the MHI technology and other industry experience.

2 CO_2 Capture Technology

2.1 Process Description

A typical amine-based CO_2 capture system consists of a quencher, an absorber column, and a stripping column; in addition, the flue gas will require a booster induced draft (ID) fan to overcome the pressure loss through the CO_2 capture system. A compressor train is also included after the stripper column. A high-level block diagram of the system is shown in

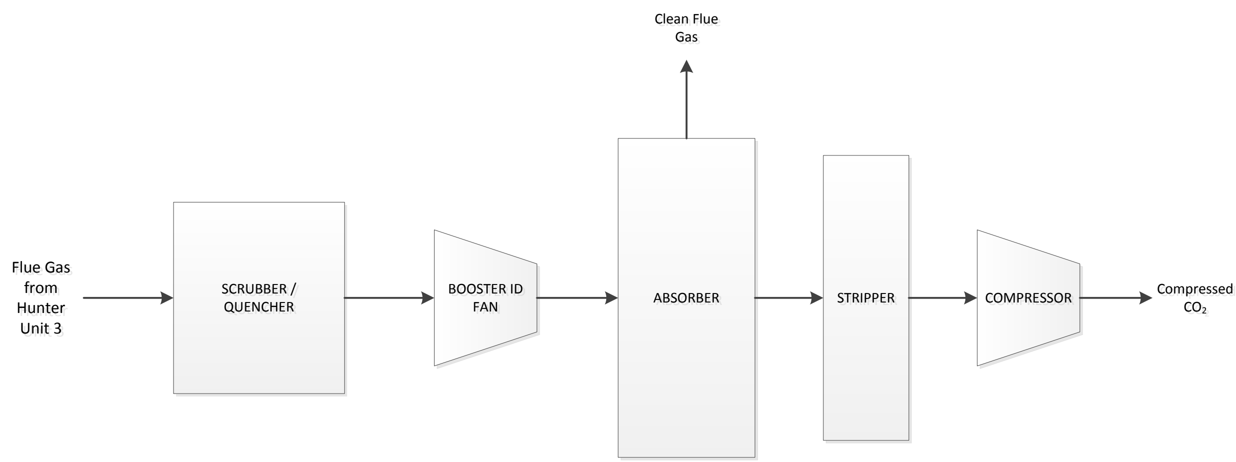


Figure 2-1: CO_2 Capture Block Diagram

Amine solvents are sensitive to impurities and will react with SO_2 and SO_3 molecules present in the flue gas. These reactions contaminate the solvent by forming intermediate salts, which in turn leads to higher solvent regeneration requirements and increased operational costs. While Hunter 3 is equipped with a lime-based WFGD system, it does not currently provide adequate SO_2 and SO_3 removal efficiency required for an amine-based system.

Additional SO_2 and SO_3 removal is required for more efficient operation of the CO_2 capture system and is completed by passing the flue gas through a caustic scrubber. The caustic scrubber uses a 10% (by weight) solution of caustic soda (NaOH) to remove residual acid gases. In the scrubber, the flue gas passes through a counter-current packed tower, where caustic solution is recirculated to scrub the flue gas to approximately 1 ppmv SO_2. Residual particulates, water, sulfates, and other soluble components will build-up in the caustic solution as it is recycled; therefore, a blowdown stream is required to reduce the concentration of contaminants and overall liquid volume. The blowdown stream is sent to a new wastewater treatment system.

In addition to removal of residual acid gases, flue gas needs to be cooled prior to being introduced to the solvent. This is due to the improved absorption efficiency of the solvent at lower temperatures. To provide this cooling, the polishing scrubber also functions as a quencher. The flue gas leaving the scrubber/quencher is cooled to approximately 100°F. The contact cooling water is cooled with a heat exchanger and returned to the quencher. The cooling process results in additional condensed water; therefore, a blowdown stream is required to reduce the volume of recirculating water. The blowdown stream is sent to the cooling tower as makeup.

The cool flue gas then passes through a counter-current packed absorber column, where the amine-solvent absorbs CO_2 present in the flue gas. Several levels of packing, spray zones, and trays facilitate the appropriate liquid-to-gas contact to ensure a high level of CO_2 absorption by the solvent (≥ 90%). The temperature of the absorber is controlled using an intercooler or heat exchanger which cools the semi-rich solvent and returns it to the absorber. A water wash is located at the top of the absorber to remove any entrained solvent in the flue gas. The clean gas exits the absorber and is exhausted through a new stack located on top of the absorber.

The CO_2 –rich solvent from the absorber enters the top of a counter-current packed stripper column, where CO_2 is desorbed from the amine-solvent through the addition of heat energy to break the weak intermediate bond between the amine-solvent and the dissolved CO_2. The reboiler at the base of the stripper utilizes low quality steam as the source of energy to vaporize water in the dilute solvent. This water vapor rises through the stripper providing energy to facilitate in stripping the CO_2 and regenerating the amine-solvent.

The hot-lean (or regenerated) solvent which is free of CO_2 is returned to the absorber. The hot-lean solvent is directed to the lean/rich exchanger to recover sensible heat and preheat the cool/rich solvent from the absorber. This preheating helps to recover some of the energy used for regeneration, reducing the overall energy requirements of the process, especially in the regeneration stage.

A mixture of CO_2 and steam exits the top of the stripper and is sent to the compressor system, which both dehydrates and compresses the CO_2 stream. The compressor is designed to pressurize the CO_2 product stream to pipeline quality. This system involves eight stages of compression including an intercooler after each stage. As part of this process, additional moisture is removed to provide a CO_2 stream with ≥ 99% purity at 2,215 psia. Moisture removed from the dehydration system and during the compression process is collected and sent back to the stripper.

Figure 2-2 shows the process flow diagram (PFD) of the CO_2 capture system for Hunter 3. It is expected that the CO_2 capture system would consist of 1x100% train, regardless of if the system is treating 100% of the flue gas (Case 2) or less than 50% (Case 3).

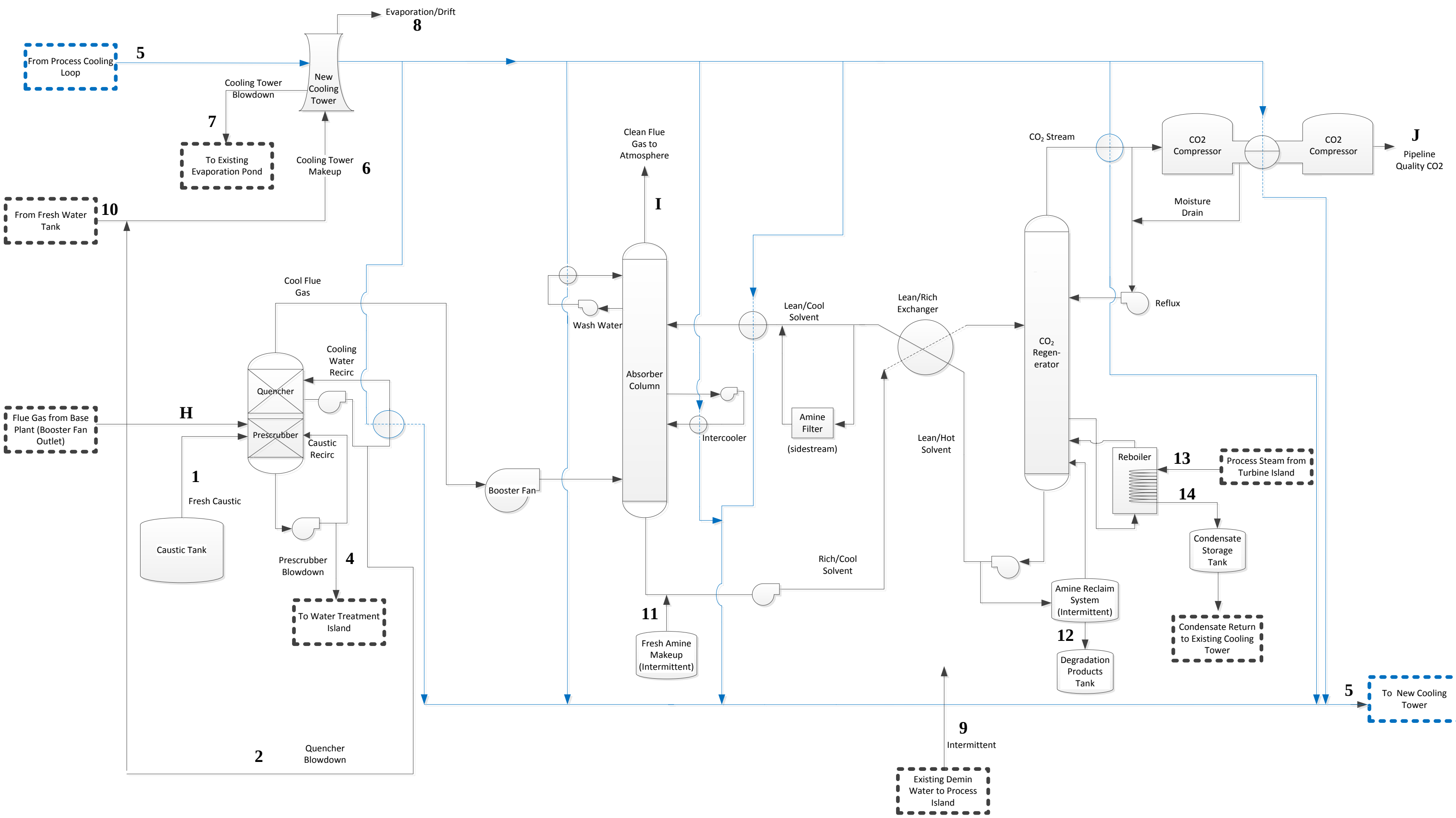


Figure 2-2: MHI CO_2 Capture Slipstream Process Flow Diagram

2.2 Integration with Hunter Unit 3

The major process equipment and BOP systems needed for a complete CO_2 capture system require a very large footprint. The Hunter property includes a relatively large open area directly adjacent to Unit 3, which was originally allocated to build Unit 4. This area is sufficiently sized to accommodate the CO_2 capture facility and to be close-coupled to the Unit. The close proximity of the CO_2 capture equipment reduces the costs of some BOP items by reducing the pipe and ductwork runs from the existing Unit to the new facility. A PFD of the base unit was developed (see Appendix B), highlighting the tie-in locations.

The ductwork to the Hunter 3 CO_2 capture system will be tied-in downstream of the existing WFGD system, prior to the stack breaching. A booster ID fan will be located in the CO_2 capture facility to pull the slipstream flue gas through the ductwork to the CO_2 capture facility. MHI's design includes locating the booster fan between the quencher and the absorber, where the gas is fully scrubbed and cooled.

The scrubbed flue gas will exit the absorber vessel through a new stack. This generates a secondary emission point that will have to be incorporated into the existing Hunter air permit. While the overall emissions are expected to be reduced based on the polishing scrubber and CO_2 capture system, there is the potential for an increase in VOC or aerosol emissions. In order to minimize the release of these emissions a second water wash is typically included in the absorber design.

The regeneration energy for the stripper comes from low quality steam, which can be provided by the unit's existing steam cycle or by a new steam generation unit. For the purposes of this study, steam will be extracted from the existing steam turbine. Low quality steam will be extracted from the crossover between the IP and LP sections of the turbine. The steam quality at the tie-in location is at a higher temperature and pressure than required by the reboiler. Some pressure will be lost through the piping from the boiler island to the CO_2 capture island, but pressure reduction and attemperation will be required once the steam reaches the CO_2 island. The associated condensate from the reboiler will be pumped back to the base plant's condensate system at the feedwater heaters.

Based on the size of the CO_2 capture facility, it is expected to be designed with 50% turndown capability. This is especially necessary for the 90% capture case, where the system is designed to treat 100% of flue gas at full load. When the base unit is dispatched at a lower load, the CO_2 capture equipment will need to be turned down to account for the smaller flue gas flow.

As part of the study, S&L reviewed the Hunter 3 steam turbine heat balances to understand approximately how much the unit will be derated due to process steam extraction. In addition, the heat balances were reviewed to ensure that the extraction rates for the maximum steam consumption case (Case 2) will not detrimentally impact the steam turbine.

The addition of a new cooling tower is included to provide cooling to the integrated heat exchangers in the CO_2 capture facility. The CO_2 capture system consists of a large quantity of heat exchangers used for process cooling as well as intercoolers to maintain temperature within the various process vessels. Process water will also be required for operation of the CO_2 island equipment for pump seals and intermittently for solvent regeneration or filtering purposes. Based on the station water balances, there is sufficient margin on the demineralizer system that can be supplied for consumption at the maximum treatment design capacity. The cooling tower consumes a large quantity of water; however, the quality of this fresh makeup water can be standard lake or well water. Information provided by the station suggests there is sufficient margin in the makeup water capacity of the reservoir on site. To minimize the amount of makeup water required for the cooling tower, water is reused from the process to the maximum extent possible. Blowdown from the new cooling towers will be reused at Hunter station, by means of the bottom ash system, where the existing cooling tower blowdown water is sent.

The CO_2 capture and BOP systems include a significant quantity of pumps, compressors, fans, and other components which will result in significant auxiliary power consumption. The primary power consumer is the compressor, which pressurizes the CO_2 stream to the required pipeline pressure. The auxiliary power can either be provided by the existing unit or a new power generation unit. For the purposes of this study, it is assumed that power will be supplied by the existing Unit, which will lower the net unit capacity. Based on the expected unit capacity factor over the next decade, it is expected that the unit will be dispatched at full load less consistently which may accommodate the loads associated with the CO_2 capture system without negatively impacting the plant.

There is additional integration with the facility based on disposal or treatment of solid and liquid wastes. Waste water generated from the caustic scrubber will be treated by a new physical/chemical wastewater treatment system; the product stream will be used for makeup water to the new cooling towers, while the sludge will be disposed of in a landfill. Blowdown from the new cooling towers will be reused by the existing facility or routed to the facility's evaporation ponds. Other potential waste streams include the degradation products of the amine-based solvent. As part of MHI's and other commercial solvent-based systems, the degraded solvent will be filtered out occasionally and disposed of separately as hazardous waste.

Makeup water, cooling tower blowdown water, demineralized water, steam supply, and condensate return piping will be routed together from the boiler building to minimize the overall plant impact, and for ease of construction.

A visual representation of the proposed plant layout can be found in Appendix D.

3 Project Design Basis

3.1 Inputs and Assumptions

Table 3-1 summarizes the major inputs and assumptions used as the basis for the design of the Hunter 3 CO_2 capture system. These inputs were based on information provided by Hunter Station, from work S&L previously completed for Hunter Station or assumptions based on those included in the US Department of Energy (DOE) and the National Energy Technology Laboratory (NETL) Report for BBS Case 12. Assumptions based on typical industry standards and engineering judgment were also used, where appropriate.

Table 3-1: Summary of Design Inputs and Assumptions

Variable	Units	Hunter Unit 3
Fuel	% composition by mass	Carbon – 65.8 Hydrogen – 4.60 Nitrogen – 1.40 Sulfur – 1.25 Chlorine– 0.02 Oxygen – 8.03 Moisture – 7.00 Ash – 11.90
Boiler Sizing	MW_{gross}	Full - 511 Low –170
Auxiliary Power Consumption	%	Full – 5.9 Low –12.8
Heat Input	MMBtu/hr	Full – 4,806 Low – 1,880
Unit Capacity Factor*	%	77

*Note: Future expected capacity factor information was provided by station personnel; 77% represents the expected average over the next decade of operation.

Table 3-2 summarizes the current properties of the Hunter 3 flue gas downstream of the WFGD system. This information is based on flue gas data provided by station personnel and recent stack test results, where available.

Table 3-2: Current Flue Gas Properties based on S&L Mass Balance

Variable	Unit	Hunter Unit 3
Flue Gas Concentration	vol %	N_2 – 70.32 O_2 – 4.17 H_2O – 13.22 CO_2 – 12.29
	lb/TBtu	Hg – 0.09
	lb/MMBtu	NO_x – 0.31
		SO_2 – 0.14
		HCl – 0.002
		PM – 0.004
	ppm	SO_2 – 56
		SO_3 – 3.5
Total Volumetric Flow	acfm	1,574,000
Total Flue Gas Mass Flow	lb/hr	5,248,000
Temperature	°F	123
Pressure	psia / in.wc.	12.063 / +1

Flue gas properties were gathered from previous reports, testing results, and other projects that S&L has completed for PacifiCorp's Hunter station. SO_2 flue gas data was provided by the station, and the highest average stack SO_2 content was selected as the basis to be conservative. Associated utility consumption rates were calculated based on these facility parameters and CO_2 quality requirements.

As part of this evaluation, three different CO_2 capture rates were explored. The largest design was based on achieving 90% removal of the CO_2 from the base facility, which sizes the capture system based on 100% of the Hunter 3 full load flue gas rate. The second largest design assumed 65% capture from the base facility, which sizes the capture system based on approximately 72% of the Hunter 3 full load flue gas rate. The smallest design uses an equivalent capture rate to an emission rate of 1,000 lbs CO_2/MWh-gross as the basis. Based on the Hunter 3 unit size and CO_2 concentration, this results in a capture system sized for approximately 48% of the Hunter 3 full load flue gas rate.

Table 3-3 summarizes the expected Hunter 3 CO_2 capture facility requirements and estimated utility consumption for each of the three capture ranges. This information is based on S&L's understanding of the MHI process, outputs from the mass balance, and pipeline standards for CO_2 delivery.

Table 3-3: CO_2 Capture Facility Requirements and CO_2 Quality

Variable	Unit	Case 1 (65% Capture)	Case 2 (90% Capture)	Case 3 (1,000 lbs/MWh_g)
CO_2 Capture	--	65%	90%	48% Capture
CO_2 Stream Purity	%	≥ 95	≥ 95	≥ 95
CO_2 Product Temperature	°F	95	95	95
CO_2 Product Stream Pressure	psia	2,215	2,215	2,215
CO_2 Production	lb/hr	640,000	887,000	473,000
	ton/yr	2,159,700	2,991,500	1,595,200
Capture Island Size	MWe	370	511	273
	lb/hr	3,790,000	5,248,000	2,799,000
	acfm	1,137,000	1,574,000	840,000
	CO_2 lb/hr	712,000	985,000	526,000
CO_2 Emissions	lb/MWh	675	193	1,002
Aux Power*	MW	Compressor – 18 Process –33	Compressor – 25 Process – 46	Compressor – 13 Process –25
Steam	lb/hr	788,000	1,000,000	617,000
Raw Make Up Water	gpm	2,600	3,600	1,900
Demin Make Up Water	gpm	20	28	15

*Note: Aux power requirement listed is in addition to the existing plant aux power requirements.

Material balance calculations were developed for the CO_2 capture systems based on this design basis and are provided in Appendix C.

3.2 System Redundancy

The CO_2 capture facility at Hunter will consist of one (1) x 100% train for any of the three capture facility sizes. Multiple trains are not typically necessary and would require additional capital cost. In addition, as operation of this unit is not critical to the operation of Hunter 3, complete train redundancy is not required. Redundancy on large complex pieces of equipment, such as the vessels and ID fans, is not necessary as this equipment is typically very reliable based on industry experience. In addition, heat exchangers, compressors, and other large components are expected to have very high availability, with regular inspections and maintenance of these pieces of equipment during scheduled outages.

4 Project Execution

4.1 Regulatory Considerations

Integration of a CO_2 capture facility at the existing Hunter station would consist of routing flue gas from the WFGD system outlet of Unit 3 to a CO_2 capture facility located on PacifiCorp property. Based on the ability to extract steam from the existing turbine and the ability to tie into the existing auxiliary power transformer, a new combustion or power source is not required. However, the CO_2 capture system may require environmental permits or approvals for air emissions, water use, wastewater discharges, and solid waste management and disposal. Specific limitations and permitting requirements depend upon the type, size, and location of the facility being permitted. Based on the preliminary design of the CO_2 capture facility, there are expected to be no fatal flaws that would prohibit the construction or operation of the new CO_2 capture facility at this time. The following permits are identified by S&L to potentially require modifications for a project of this scope:

- Application for a revised Title V permit from the WDEQ;
- Determination of composition and treatment requirements for the process wastewaters or if they can be treated using the existing resources onsite;
- Application for a revised NPDES permit, if necessary;
- Determination of whether a new solid waste stream from wastewater sludge dewatering could be disposed at another landfill that accepts industrial solid wastes; and
- Determination of whether a new hazardous waste stream of the amine degradation products could be disposed of off-site at a facility that accepts industrial or hazardous wastes.

While it is not expected that the project has any fatal flaws at this time, there may be some limitation to the facility size and, subsequently, the compressed CO_2 production rate, based on some permitting requirements. The factors that have the highest probability of becoming limiting factors moving forward are (1) the ability to permit a new point source as part of the station's Title V permit and (2) the potential for PSD permitting to be triggered, based on criteria pollutant emissions increases. VOC emissions would have the highest likelihood of increasing after project execution.

Based on the flue gas treatment equipment that is integrated with the CO_2 capture facility, the base unit air emissions are expected to change, resulting in decreased CO_2, SO_2, SO_3, and PM emissions. Mercury and NOx rates are also likely to decrease, though this has not been well documented at this time. VOC emissions or aerosols have the biggest potential to increase with amine-based technology CO_2 capture projects due to amine carryover. As discussed previously, a second water wash section in the top of the absorber column will help reduce the potential for an increase in emissions. At this time, it is unknown what changes to VOC or aerosol emissions might occur, if any.

Table 4-1: Estimated Emission Changes

Variable	Unit	Baseline Emissions	Case 1 (65% Capture)	Case 2 (90% Capture)	Case 3 (1,000 lb/MWh$_g$)
CO_2	lb/hr	984,920	344,722	98,492	512,158
SO_2	lb/hr	654	191	13	312
SO_3	lb/hr	51	41	38	44
HCl	lb/hr	8	3	1	4
NOx	lb/hr	1,490	1,490	1,490	1,490
Hg	lb/hr	0.00043	0.00043	0.00043	0.00043
VOC	lb/hr	unknown	unknown	unknown	unknown
PM	lb/hr	20	17	15	18

In addition to air, water, and waste permits, there is the need for construction permits for the construction of the CO_2 capture facility and a new pipeline. Permits and approvals will be required at the federal and state level to construct and operate theses.

4.2 Overall Net Output Impact

As discussed previously, there are two parameters that will derate the base facility: steam extraction and auxiliary power usage. The steam extraction from the IP/LP cross-over reduces the overall gross capacity of the turbine by removing the steam prior to passing through the LP turbine. Based on review of the Hunter 3 heat balance, it is estimated that the gross output is derated by approximately 63 MW for the 90% capture case. The overall derate for the 90% capture case can be seen in Appendix A. At the lower capture rates, the derate will be less, but is not expected to scale linearly. The CO_2 capture facility also utilizes a significant amount of auxiliary power to operate the mechanical equipment. This also reduces the net power that can be provided to the grid and is provided by the station's existing auxiliary power transformers and metered within the fence-line. Based on the sizes of the facility, the total net output of the unit for each case is provided below.

Table 4-2: Plant Net Output with CO_2 Capture

	Case 1 (65% Capture)	Case 2 (90% Capture)	Case 3 (1,000 lb/MWh$_g$)
Gross Boiler Size/Steam Generation	**511**	**511**	**511**
Process Steam Equivalent Power Derate	54	63	47
Steam Turbine Gross Output	**457**	**448**	**464**
Base Plant Aux Power	30	30	30
CO_2 Island Process Aux Power	33	46	25
CO_2 Compressor Aux Power	18	25	13
CO_2 Island BOP	3	4	2
Net Power Output	**373**	**343**	**394**

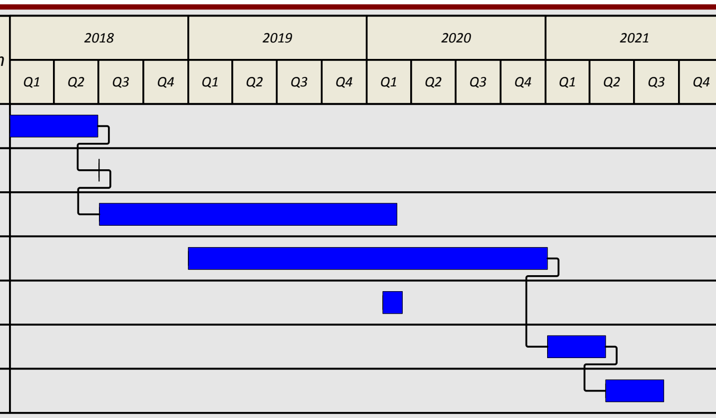
When the CO_2 capture facility is not in operation, the station regains full gross capacity of 511 MWg.

4.3 Project Schedule

As with any large retrofit project, a new CO_2 capture facility requires a schedule of significant duration, regardless of size. Due to the infancy of the technology being developed on a commercial scale size, there is an extended preliminary development period required prior to beginning detailed engineering. A project of this size would likely include a Front End Engineering and Design (FEED) study prior to award, which would consist of developing technical requirements and more detailed costs. After the FEED study, the project would be competitively bid to qualified vendors and an award would start the engineering process. BOP engineering and CCS engineering would be completed concurrently. Depending on the overall project scope, construction can start about six months after award and will continue for around two years. After all tie-ins are complete and all equipment is installed onsite, commissioning and performance testing will take place, ensuring all equipment is working as intended individually and as a system. This is expected to require approximately eight months after construction. A high level example schedule is provided in Figure 4-1.

Figure 4-1: Milestone Project Schedule

ID	Task Name	Start	Finish	Duration
1	Conduct FEED Study	1/1/2018	6/29/2018	26w
2	Award Contracts	7/2/2018	7/2/2018	1d
3	Engineering	7/3/2018	3/2/2020	87w
4	Construction	1/1/2019	1/4/2021	105w
5	Unit Tie-In	2/3/2020	3/13/2020	6w
6	Commissioning	1/5/2021	5/3/2021	17w
7	Final Acceptance Testing	5/4/2021	8/30/2021	17w



5 Economic Evaluation

5.1 Capital Costs

CO_2 capture island equipment costs were estimated based on S&L proprietary costs, budgetary pricing and allowances. All costs are provided in 2017 dollars. Installation costs were estimated by S&L based on similar work. Labor costs were estimated for each individual subcontracted process or component rather than a blanket percentage over the whole project, and include the associated labor indirect costs which apply to this type of work such as overtime, per diem, contractor's G&A and profit.

Project contingency was added, due to the risk of a relatively new technology application. A contingency factor of 20% was added to the BOP project scope only, since the CO_2 capture system risk is accounted for in the EPC fee. Indirect project costs, such as engineering, construction management, startup and commissioning support, construction materials and initial fills for testing were also included in the estimate to provide a total capital investment. Owner's costs were not included.

The overall cost for the commercially available amine-based CO_2 capture system is provided for each of the three facility sizes. Table 5-1 provides a breakdown of the capital cost.

Table 5-1: Capital Cost Summary of CO_2 Capture Slipstream Systems

Description	**Case 1 (65% Capture)**	**Case 2 (90% Capture)**	**Case 3 (1,000 lb/MWh$_g$)**
BOP Scope			
Civil, Site Prep, and Structural	6,168,200	7,125,500	5,434,200
Architectural	4,812,000	5,850,000	4,016,100
Mechanical	15,945,200	18,867,300	13,704,900
Electrical and I&C	2,342,900	2,342,900	2,342,900
CO_2 Capture System (EPC)	470,000,000	610,000,000	380,000,000
Total Direct Capital Cost	**499,268,300**	**644,185,700**	**405,498,100**
Other Direct and Construction Indirect Costs (Excludes EPC)	6,221,000	7,266,000	5,420,000
Engineering (Excludes EPC)	3,549,000	4,145,000	3,092,000
Construction Management (Excludes EPC)	710,000	829,000	618,000
Startup/Commissioning (Excludes EPC)	366,000	427,000	318,000
Contingency (Excludes	8,022,000	9,370,000	6,989,000

Description	Case 1 (65% Capture)	Case 2 (90% Capture)	Case 3 (1,000 lb/MWh$_g$)
EPC)			
Total Capital Investment	**518,136,300**	**666,222,700**	**421,935,100**

5.2 Operating Costs

Operating costs were estimated based on a capacity factor of 77% and are provided in 2017 dollars. Unit costs for consumables were estimated by S&L, except as noted. Fixed O&M costs for operators, maintenance material and labor, and administrative labor costs were also included based on typical assumptions.

The overall O&M cost for the commercially available amine-based CO_2 capture system is provided for each of the three facility sizes. Table 5-2 provides a breakdown of the annual O&M cost.

Table 5-2: O&M Cost Summary of CO_2 Capture Slipstream Systems

Description	Case 1 (65% Capture)	Case 2 (90% Capture)	Case 3 (1,000 lb/MWh$_g$)
Total Fixed Operating Cost	**7,195,000**	**7,195,000**	**7,195,000**
Annual Operating Labor[1]	3,295,000	3,295,000	3,295,000
Maintenance Material & Labor	3,900,000	3,900,000	3,900,000
Total Variable Operating Cost	**39,492,000**	**51,507,000**	**31,030,000**
Makeup Water	1,052,000	1,465,000	769,000
Demin Makeup Water	41,000	57,000	30,000
Water Treatment[2]	356,000	454,000	235,000
Pre-scrubber Caustic Solution	809,000	1,079,000	540,000
Lost Generation/Auxiliary Power	14,570,000	20,236,000	10,793,000
Lost Generation/Process Steam	14,570,000	16,998,000	12,681,000
CO_2 Capture Solvent[3]	8,094,000	11,218,000	5,982,000
CO_2 Transportation, Storage and Monitoring [4]	**19,581,000**	**27,138,000**	**14,472,000**
Total Annual O&M Cost	**66,268,000**	**85,840,000**	**52,697,000**

Notes:

1. Operating labor is based on the addition of 24 operators for the CO_2 capture system.
2. Water treatment costs include chemical and solids disposal costs.
3. Solvent costs include the cost for new makeup solvent and disposal of the degradation products.
4. TS&M is based on the DOE suggested rate of $10/tonne of CO_2 captured.

5.3 Cost of Capture

To calculate the total cost per mass of CO_2 captured, all costs must be evaluated on an annual basis. In previous U.S. Department of Energy (DOE) case studies, a capital annualization factor of 0.1243 was used to evaluate costs on a constant dollar basis. This methodology was used to calculate the total cost of capture for this TEA. Table 5-3 provides an estimate of the total quantity of CO_2 captured in a year as well as the evaluated cost for the CO_2 capture system.

Table 5-3: Evaluated Cost of CO_2 Capture Systems

Description	**Units**	**Case 1 (65% Capture)**	**Case 2 (90% Capture)**	**Case 3 (1,000 lb/MWh_g)**
Total Capital Cost	$	518,136,300	666,222,700	421,935,100
CCF		0.1243	0.1243	0.1243
Annualized Capital Cost	$/yr	64,404,400	82,811,500	52,446,600
Annual O&M Cost	$/yr	66,268,000	85,840,000	52,697,000
Total Annual Cost	$/yr	130,672,400	149,079,500	118,714,600
Annual CO_2 Captured	tons	2,158,460	2,991,500	1,595,240
Cost of Capture	**$/ton**	61	50	74

6 Summary and Conclusions

The purpose of this TEA was to determine the technical and economic feasibility of installing a CO_2 capture facility at Hunter Station, utilizing a commercially available technology at three different capture scales. A full scale capture system (Case 2: 90% capture) served as the basis for development of heat balances, mass balances, process flow diagrams, general arrangements, equipment sizing, and capital costs. Case 2 represents the worst case scenario with respect to impacts on the base unit and, therefore, the other levels of capture will be feasible if this level of capture is deemed feasible. The full scale system inputs were adjusted for the two other capture facility design sizes: Case 1: 65% and Case 3: 1,000 lb CO_2/MWh_g.

Overall, the project is technically feasible for implementation on PacifiCorp's Hunter Unit 3. Process steam will be provided by the base unit and extracted at the IP/LP crossover without disrupting the performance of the LP turbine; however, this will cause a unit derate by limiting the total amount of megawatts the turbines can produce. Other utilities that the base plant will provide include process water makeup from the existing demineralized water system, cooling tower makeup water from the on-site storage basin, and auxiliary power from the existing auxiliary power transformer. Flue gas will be routed to the CO_2 capture island after the majority of SO_2 has been removed from the WFGD system, which reduces the amount of acid gas polishing that is required in the pre-scrubber. The CO_2 process is expected to generate pipeline quality liquid CO_2 for transportation to a storage field or an EOR facility.

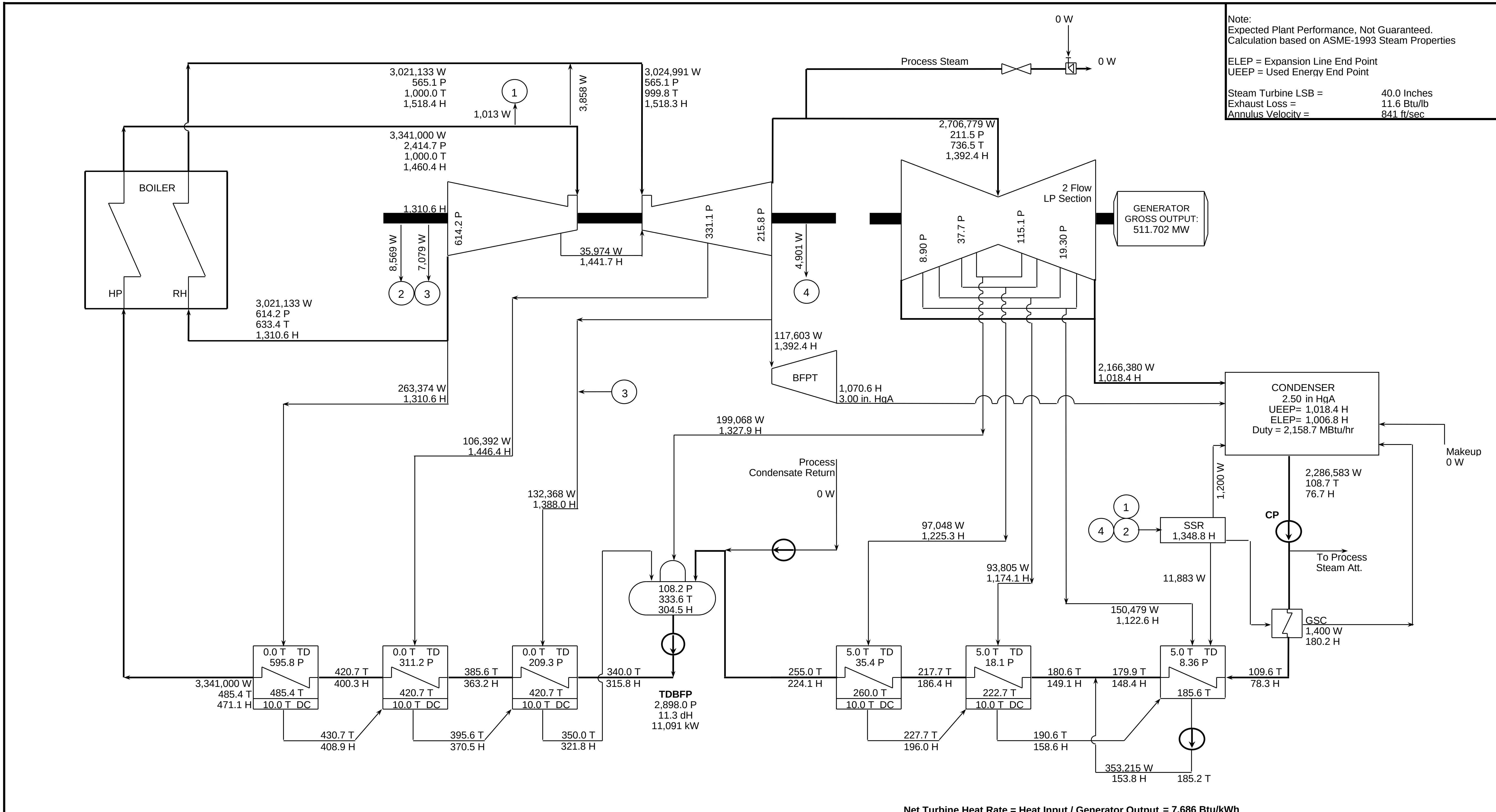
As part of this evaluation, S&L developed capital costs, O&M costs, and cost of capture for each of the three cases. Using previous information gathered from MHI and S&L's engineering judgement, the system design and costs were developed based on the MHI KM-CR Process® with KS-1™ solvent. Due to economies of scale, the overall cost of capture ($/ton of CO_2 removed) is less at larger capture rates. Depending on the project size selected, the cost of capture ranges from $50-74/ton CO_2 removed.

APPENDIX A: HEAT BALANCE (90% CAPTURE – CASE 2)

PRELIMINARY
Carbon Capture Study
Process Steam Extraction

Notes and Assumptions:

1. Steam Turbine (ST) design is based on Hitachi, Ltd heat balance diagram 310SC74-636 Rev. 0, dated Dec. 11, 2008.
   Steam turbine is a TC2F machine with a 40.0" last stage blade length, operating at 3600 RPM (60 Hz).
   A typical exhaust loss curve for this last stage blade length was used to approximate the exhaust loss.
   ST generator efficiency is based on Hitachi, Ltd heat balance diagram 310SC74-636 Rev. 0, dated Dec. 11, 2008.
2. Boiler feed pump turbine drive efficiency is per reference heat balance and is assumed constant for all cases.
3. Feedwater heater operating conditions are based on Hitachi, Ltd heat balance diagram 310SC74-636 Rev. 0, dated Dec. 11, 2008.
   It is assumed that constant terminal temperature differences and drain cooler approach temperatures are maintained for all cases.
4. Condenser design operating pressure = 2.5 inHgA based on the reference heat balance.
5. Match case uses no deaerator venting flow rate per Hitachi, Ltd heat balance diagram 310SC74-636 Rev. 0, dated Dec. 11, 2008.
   All other cases assume deaerator venting of 0.25% of the incoming feedwater flow rate.
6. Carbon capture process Steam is supplied by extracting steam from the IP crossover and attemperating to the required process conditions.
   Clean condensate is returned from the carbon capture process and re-enters the cycle at the deaerator.
   A 99% condensate return rate is assumed.
   A pressure loss of 20% is assumed from the process steam exit to the process condensate return.
   Process condensate is assumed to return with 5°F of subcooling.
   It is assumed that condensate polishing of the returning condensate is not required.
7. Process Steam conditions are as follows:
   Pressure: 85.7 psia (71 psig)
   Temperature: 320°F (3°F of superheat)
8. Piping, reheater, and extraction losses are based on Hitachi, Ltd heat balance diagram 310SC74-636 Rev. 0, dated Dec. 11, 2008.
9. Heat balance results determined using GateCycle Program, Version 6.1.2
   Steam Property Method: ASME 1993 steam properties are used to match Hitachi heat balance.
   All other cases use the IAPWS-IF97 (ASME 1999) steam properties.



PRELIMINARY

Legend:		
W=	Flow	lb/h
P=	Pressure	psia
T=	Temp.	°F
H=	Enthalpy	Btu/Lb

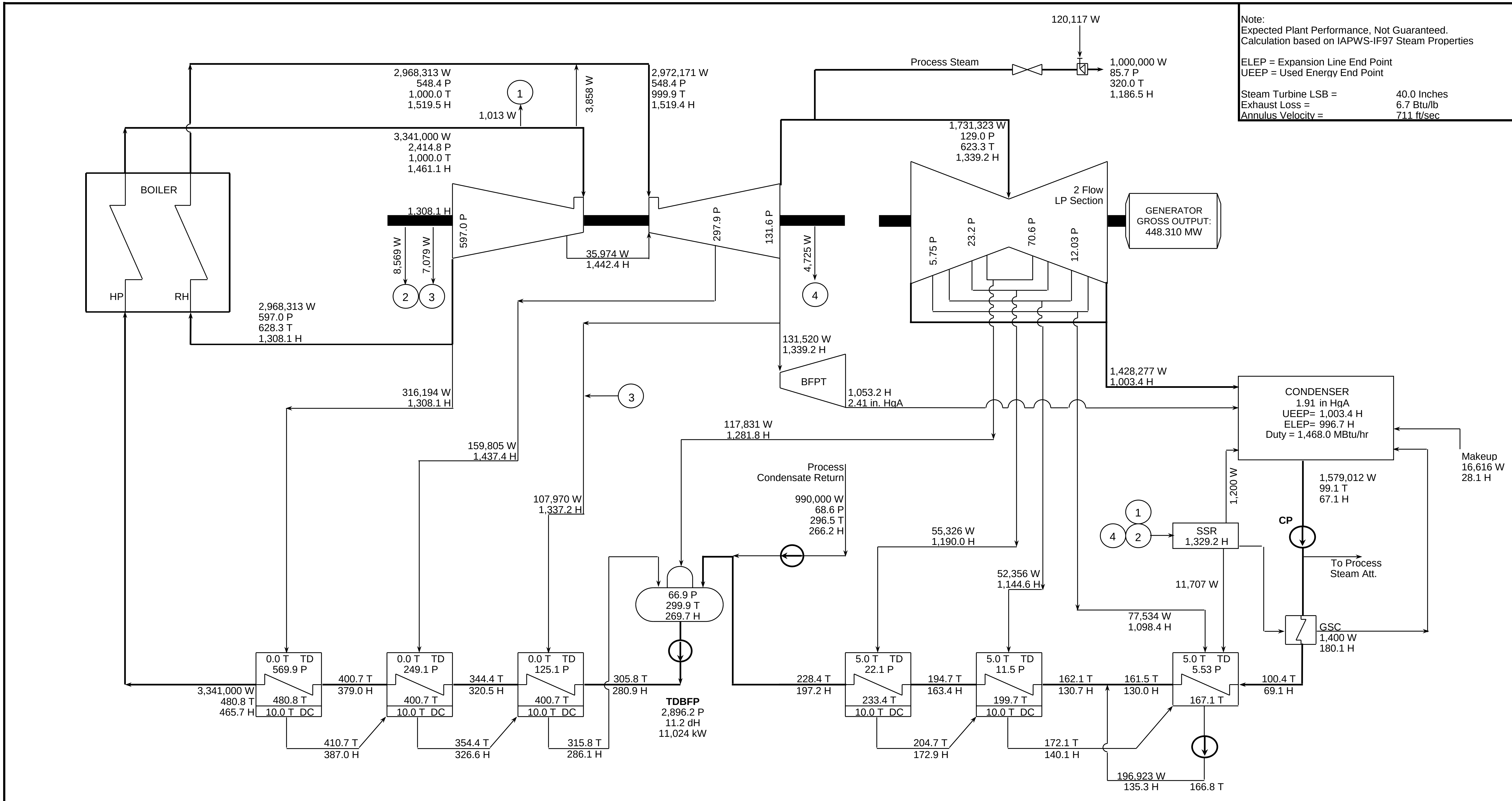
Drawing Release Record

Rev.	Date	Prepared	Reviewed	Approved	Purpose
0	31-Oct-2017	D Jarard	J Cobb		Original Issue

Project No.:	
13644-001	
GateCycle v6.1.2	
Model	Case
HU3	HU3

University of Utah
Hunter Unit 3 Carbon Capture Study
Expected Performance Summary
Match Case: No Process Steam Extraction

Sargent & Lundy LLC



Net Turbine Heat Rate = Heat Input / Generator Output = 8,818 Btu/kWh

PRELIMINARY

Legend:		
W=	Flow	lb/h
P=	Pressure	psia
T=	Temp.	°F
H=	Enthalpy	Btu/Lb

Drawing Release Record

Rev.	Date	Prepared	Reviewed	Approved	Purpose
0	31-Oct-2017	D Jarard	J Cobb		Original Issue

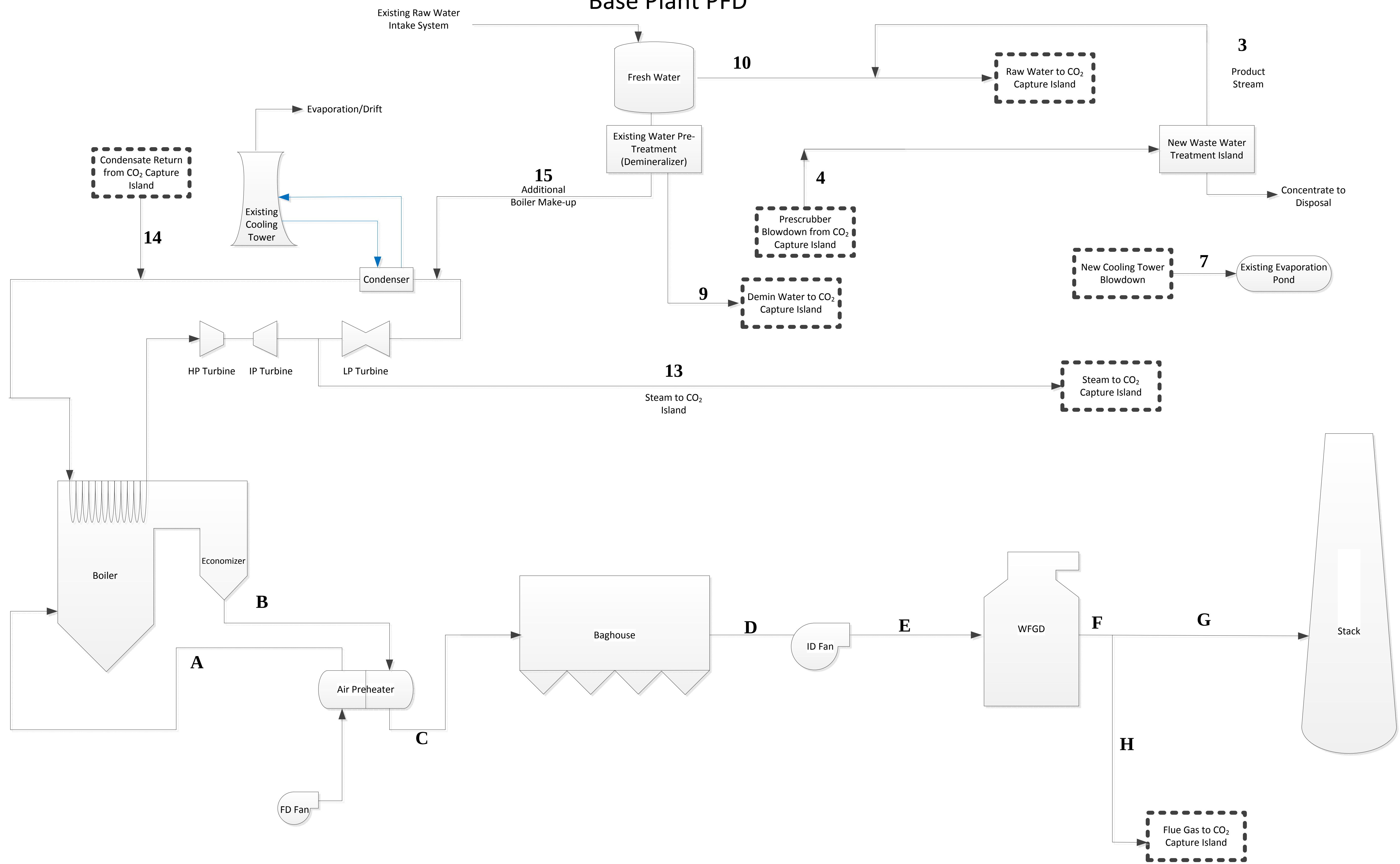
Project No.:	
13644-001	
GateCycle v6.1.2	
Model	Case
HU3	Case1

University of Utah
Hunter Unit 3 Carbon Capture Study
Expected Performance Summary
Case 1: 1,000,000 lb/hr Process Steam

Sargent & Lundy

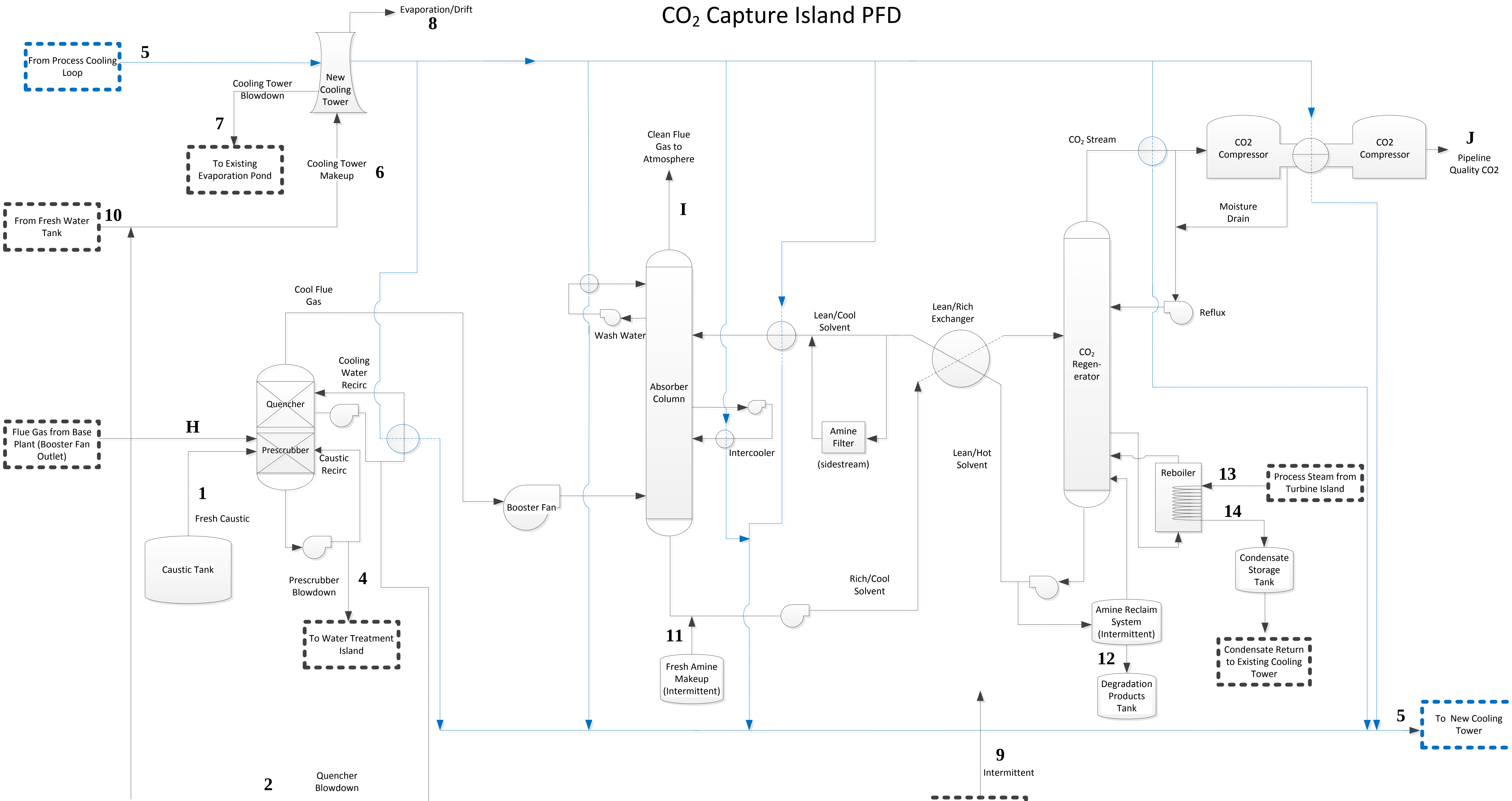
APPENDIX B: BASE PLANT PROCESS FLOW DIAGRAM

Base Plant PFD



APPENDIX C: CO_2 ISLAND PROCESS FLOW DIAGRAM AND MATERIAL BALANCES

CO_2 Capture Island PFD



Case 1: Material Balance - 65% CO_2 Capture

Flue Gas Stream Characteristics		Combustion Air		Economizer Outlet		Air Heater Outlet		Baghouse Outlet		ID Fan Outlet		Wet FGD Outlet		To Existing Stack		To CO2 Capture Island		Clean Flue Gas to New Stack		Pipeline Quality CO2	
		A		B		C		D		E		F		G		H		I		J	
Temperature	°F	103		750		300		300		316		123		123		123		Proprietary		112	
Pressure	psia	12.027		11.775		11.558		11.270		12.387		12.063		12.063		12.063		12.045		2215	
N2	lb/hr-vol%	3,237,000	76.09	3,242,000	72.66	3,563,000	72.95	3,563,000	72.95	3,563,000	72.95	3,586,000	70.32	996,000	19.53	2,590,000	70.32	2,590,000	85.52	0	0.00
O2	lb/hr-vol%	975,000	20.06	142,000	2.78	238,000	4.27	238,000	4.27	238,000	4.27	243,000	4.17	67,000	1.16	175,000	4.17	175,000	5.07	0	0.00
H2O	lb/hr-vol%	105,000	3.85	302,000	10.51	312,000	9.94	312,000	9.94	312,000	9.94	433,000	13.22	120,000	3.67	313,000	13.22	154,000	7.91	157	0.06
CO2	lb/hr-vol%	0	0.00	978,000	13.95	978,000	12.75	978,000	12.75	978,000	12.75	985,000	12.29	274,000	3.41	712,000	12.29	72,000	1.49	640,000	99.94
SO2	lb/hr-ppmv	0	0	10,000	986	10,000	901	10,000	901	10,000	901	700	56	180	56	500	56	9	1	0	0
SO3	lb/hr-ppmv	0	0	100	8	71	5	67	5	67	5	51	3	14	3	37	3	27	3	0	0
HCl	lb/hr-ppmv	0	0	83	14	83	13	83	13	83	13	8	1	2	1	6	1	1	0	0	0
HF	lb/hr-ppmv	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NOx	lb/mmbtu	0		0.31		0.31		0.31		0.31		0.31		0.31		0.31		0.31		0	
Hg	lb/tbtu	0		10		0.09		0.09		0.09		0.09		0.09		0.09		0.09		0	
Total Flow	lb/hr-acfm	4,317,000	1,271,000	4,674,000	2,928,000	5,101,000	2,050,000	5,101,000	2,103,000	5,101,000	1,952,000	5,248,000	1,574,000	1,458,000	437,000	3,790,000	1,137,000	2,991,000	910,000	640,000	700
Moist.	lb/lb	0.025		0.069		0.065		0.065		0.065		0.090		0.090		0.090		0.054		0.000	
MW	lb/lbmol	28.42		29.33		29.25		29.25		29.25		28.81		28.81		28.81		27.65		43.98	
Ash	lb/hr	0		38,606		38,606		27		27		20		6		15		11		0	

Process Stream Characteristics		Fresh Caustic	Quencher Blowdown	WWT Recovery	Prescrubber Blowdown	CO2 Cooling Loop	Cooling Tower Water Makeup	Cooling Tower Water Blowdown	Cooling Tower Water Evaporation	Process Water Makeup	Fresh Water to CT	Amine Make Up	Degradation Products	Steam to CO2 Island	Condensate Return	Additional Boiler Makeup
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Solids	lb/hr	300	0	0	300	0	0	0	0	0	288	0	0	288	0	0
Water	lb/hr	3,000	124,700	22,700	31,600	67,728,000	1,444,200	360,500	1,083,600	Intermittent	1,296,700	0	0	788,000	779,300	8,700
Total Flow	lb/hr	3,300	124,700	22,700	31,900	67,728,000	1,444,200	360,500	1,083,600	Intermittent	1,297,000	Intermittent	Intermittent	788,000	779,300	8,700
Total Flow	gpm	5	300	50	100	136,000	2,900	700	2,200	Intermittent	2,600	Intermittent	Intermittent	--	--	--
Solids	wt%	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Case 2: Material Balance - 90% CO_2 Capture

Flue Gas Stream Characteristics		Combustion Air		Economizer Outlet		Air Heater Outlet		Baghouse Outlet		ID Fan Outlet		Wet FGD Outlet		To Existing Stack		To CO2 Capture Island		Clean Flue Gas to New Stack		Pipeline Quality CO2	
		A		B		C		D		E		F		G		H		I		J	
Temperature	°F	103		750		300		300		316		123		123		123		Proprietary		112	
Pressure	psia	12.027		11.775		11.558		11.270		12.387		12.063		12.063		12.063		12.045		2215	
N2	lb/hr-vol%	3,237,000	76.09	3,242,000	72.66	3,563,000	72.95	3,563,000	72.95	3,563,000	72.95	3,586,000	70.32	0	0.00	3,586,000	70.32	3,586,000	85.52	0	0.00
O2	lb/hr-vol%	975,000	20.06	142,000	2.78	238,000	4.27	238,000	4.27	238,000	4.27	243,000	4.17	0	0.00	243,000	4.17	243,000	5.07	0	0.00
H2O	lb/hr-vol%	105,000	3.85	302,000	10.51	312,000	9.94	312,000	9.94	312,000	9.94	433,000	13.22	0	0.00	433,000	13.22	213,000	7.91	218	0.06
CO2	lb/hr-vol%	0	0.00	978,000	13.95	978,000	12.75	978,000	12.75	978,000	12.75	985,000	12.29	0	0.00	985,000	12.29	99,000	1.49	886,000	99.94
SO2	lb/hr-ppmv	0	0	10,000	986	10,000	901	10,000	901	10,000	901	700	56	0	0	700	56	13	1	0	0
SO3	lb/hr-ppmv	0	0	100	8	71	5	67	5	67	5	51	3	0	0	51	3	38	3	0	0
HCl	lb/hr-ppmv	0	0	83	14	83	13	83	13	83	13	8	1	0	0	8	1	1	0	0	0
HF	lb/hr-ppmv	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NOx	lb/mmbtu	0		0.31		0.31		0.31		0.31		0.31		0.00		0.31		0.31		0	
Hg	lb/tbtu	0		10		0.09		0.09		0.09		0.09		0.00		0.09		0.09		0	
Total Flow	lb/hr-acfm	4,317,000	1,271,000	4,674,000	2,928,000	5,101,000	2,050,000	5,101,000	2,103,000	5,101,000	1,952,000	5,248,000	1,574,000	0	0	5,248,000	1,574,000	4,141,000	1,260,000	887,000	900
Moist.	lb/lb	0.025		0.069		0.065		0.065		0.065		0.090		0.000		0.090		0.054		0.000	
MW	lb/lbmol	28.42		29.33		29.25		29.25		29.25		28.81		0.00		28.81		27.65		43.98	
Ash	lb/hr	0		38,606		38,606		27		27		20		0		20		15		0	

Process Stream Characteristics		Fresh Caustic	Quencher Blowdown	WWT Recovery	Prescrubber Blowdown	CO2 Cooling Loop	Cooling Tower Water Makeup	Cooling Tower Water Blowdown	Cooling Tower Water Evaporation	Process Water Makeup	Fresh Water to CT	Amine Make Up	Degradation Products	Steam to CO2 Island	Condensate Return	Additional Boiler Makeup
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Solids	lb/hr	400	0	0	400	0	0	0	0	0	399	0	0	399	0	0
Water	lb/hr	4,100	172,700	31,500	43,700	94,122,000	2,007,000	501,000	1,506,000	Intermittent	1,802,800	0	0	1,000,000	990,000	10,000
Total Flow	lb/hr	4,500	172,700	31,500	44,100	94,122,000	2,007,000	501,000	1,506,000	Intermittent	1,803,200	Intermittent	Intermittent	1,000,000	990,000	10,000
Total Flow	gpm	10	350	60	90	189,000	4,030	1,010	3,020	Intermittent	3,620	Intermittent	Intermittent	--	--	--
Solids	wt%	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Case 3: Material Balance – 1,000 lb/MWhg

Flue Gas Stream Characteristics		Combustion Air		Economizer Outlet		Air Heater Outlet		Baghouse Outlet		ID Fan Outlet		Wet FGD Outlet		To Existing Stack		To CO2 Capture Island		Clean Flue Gas to New Stack		Pipeline Quality CO2	
		A		B		C		D		E		F		G		H		I		J	
Temperature	°F	103		750		300		300		316		123		123		123		Proprietary		112	
Pressure	psia	12.027		11.775		11.558		11.270		12.387		12.063		12.063		12.063		12.045		2215	
N2	lb/hr-vol%	3,237,000	76.09	3,242,000	72.66	3,563,000	72.95	3,563,000	72.95	3,563,000	72.95	3,586,000	70.32	1,674,000	64.13	1,913,000	70.32	1,913,000	85.52	0	0.00
O2	lb/hr-vol%	975,000	20.06	142,000	2.78	238,000	4.27	238,000	4.27	238,000	4.27	243,000	4.17	113,000	3.80	130,000	4.17	130,000	5.07	0	0.00
H2O	lb/hr-vol%	105,000	3.85	302,000	10.51	312,000	9.94	312,000	9.94	312,000	9.94	433,000	13.22	202,000	12.05	231,000	13.22	114,000	7.91	116	0.06
CO2	lb/hr-vol%	0	0.00	978,000	13.95	978,000	12.75	978,000	12.75	978,000	12.75	985,000	12.29	460,000	11.21	526,000	12.29	53,000	1.49	473,000	99.94
SO2	lb/hr-ppmv	0	0	10,000	986	10,000	901	10,000	901	10,000	901	700	56	310	56	300	56	7	1	0	0
SO3	lb/hr-ppmv	0	0	100	8	71	5	67	5	67	5	51	3	24	4	27	3	20	3	0	0
HCl	lb/hr-ppmv	0	0	83	14	83	13	83	13	83	13	8	1	4	1	4	1	0	0	0	0
HF	lb/hr-ppmv	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NOx	lb/mmbtu	0		0.31		0.31		0.31		0.31		0.31		0.31		0.31		0.31		0	
Hg	lb/tbtu	0		10		0.09		0.09		0.09		0.09		0.09		0.09		0.09		0	
Total Flow	lb/hr-acfm	4,317,000	1,271,000	4,674,000	2,928,000	5,101,000	2,050,000	5,101,000	2,103,000	5,101,000	1,952,000	5,248,000	1,574,000	2,449,000	734,000	2,799,000	840,000	2,208,000	672,000	473,000	500
Moist.	lb/lb	0.025		0.069		0.065		0.065		0.065		0.090		0.090		0.090		0.054		0.000	
MW	lb/lbmol	28.42		29.33		29.25		29.25		29.25		28.81		28.81		28.81		27.65		43.98	
Ash	lb/hr	0		38,606		38,606		27		27		20		9		11		8		0	

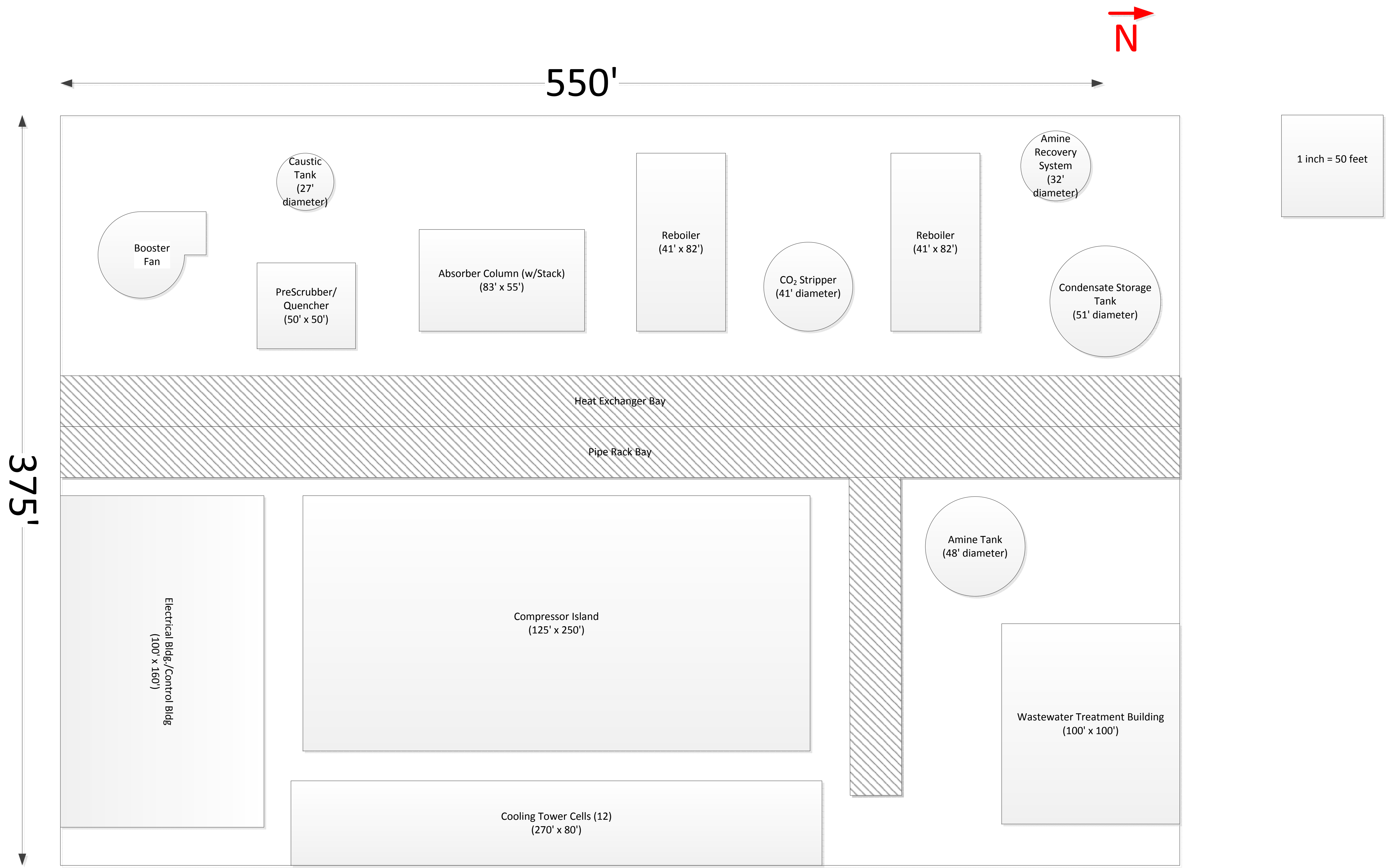
Process Stream Characteristics		Fresh Caustic	Quencher Blowdown	WWTRecovery	Prescrubber Blowdown	CO2 Cooling Loop	Cooling Tower Water Makeup	Cooling Tower Water Blowdown	Cooling Tower Water Evaporation	Process Water Makeup	Fresh Water to CT	Amine Make Up	Degradation Products	Steam to CO2 Island	Condensate Return	Additional Boiler Makeup
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Solids	lb/hr	200	0	0	200	0	0	0	0	0	213	0	0	213	0	0
Water	lb/hr	2,200	92,100	16,800	23,300	50,298,000	1,072,500	267,800	804,800	Intermittent	963,600	0	0	617,000	610,220	6,790
Total Flow	lb/hr	2,400	92,100	16,800	23,500	50,298,000	1,072,500	267,800	804,800	Intermittent	963,800	Intermittent	Intermittent	617,000	610,220	6,790
Total Flow	gpm	5	200	30	50	101,000	2,200	500	1,600	Intermittent	1,900	Intermittent	Intermittent	--	--	--
Solids	wt%	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0

APPENDIX D: GENERAL ARRANGEMENT AND PLANT LAYOUT (90% CAPTURE – CASE 2)

University of Utah
Hunter Unit 3 CO_2 Capture Project
General Arrangement
Appendix D

Project No.: 13644-001
Issue: FINAL, Rev. 0
Date: 12/15/2017

CO_2 Capture Island Layout



Sargent & Lundy

Site Plan

Rocky Mountain CarbonSAFE Phase I

Appendix B

SUBSURFACE MAPPING

SUBSURFACE MAPPING

Craig D. Morgan and Thomas C. Chidsey, Jr.,
Utah Geological Survey

INTRODUCTION

Depth, structure, and thickness maps of key reservoir and seal formations were prepared for the CarbonSafe study area. Geophysical logs from oil and gas wells were correlated within the Castle Valley and San Rafael Swell area to develop a database for the region; geophysical logs of significant wells were digitized. The oil and gas well tops are from the Utah Geological Survey (UGS) state-wide databases. The UGS downloaded basic well information from the Utah Division of Oil, Gas and Mining (DOGM) files and added formation top information from numerous sources such as DOGM, published papers, and tops picked by the UGS geologists. The spatial analyst interpolation tool and the natural neighbor algorithm in ARCGIS software were used to create maps from data in the well database. Both regional and site-specific areas were mapped (figure 1-2).

Key reservoirs in the study area are the Mississippian Redwall Limestone, Permian White Rim Sandstone, and Jurassic Navajo Sandstone (figure 1-4). Key seals are the Permian Kaibab Formation, Triassic Moenkpoi Formation, and Jurassic Carmel Formation (figure 1-4). The Cretaceous Ferron Sandstone Member of the Mancos Shale is an important coal-bed methane producer.

Castle Valley lies on the west flank of the San Rafael Swell with formations dipping to the west-northwest (figures 1-1 and 1-3). There are no major structural closers at depth near the Hunter Power Plant so injection must be sufficiently downdip from the outcrop to avoid the CO_2 migrating to a depth where the phase change from high-density CO_2 to CO_2 gas takes place, approximately 2500 to 3000 feet.

KEY RESERVOIRS

Mississippian Redwall Limestone

The Mississippian Redwall Limestone (also known as the Leadville Limestone) (figure 1-4) is an important oil and gas reservoir in the Paradox Basin of southeast Utah and southwest Colorado. Hydrocarbons have been produced from Lisbon, Salt Wash, Big Flat, and Cleft oil fields and Big Indian, Lightning Draw Southeast, and Little Valley gas fields in Grand and San Juan Counties, Utah (Chidsey and Eby, 2016). The Redwall has been an exploration target in Carbon and Emery Counties but there is no production from the Mississippian reservoir.

The Redwall Limestone in Utah's Colorado Plateau is a shallow-marine shelf carbonate platform deposit with the deep basin to the west, spanning the middle Kinderhookian through the middle Meramecian (Rose, 1976; Hintze and Kowallis, 2009). During Late Mississippian time the carbonate platform in Utah was subaerially exposed resulting in carbonate dissolution, solution breccias, and karstified surfaces (Fouret, 1996; Chidsey and Eby, 2016). In the northern San Rafael Swell, the Redwall is overlain by the Mississippian Humbug and Doughnut

Formations (Morgan and Wanders, 2013). In most of the San Rafael Swell and in Castle Valley near the Hunter Power Plant, the Redwall is overlain by the Pennsylvanian Elephant Canyon Formation and the two are separated by an unconformity representing up to 60 million years (Hintze and Kowallis, 2009). Some paleohighs formed before deposition of the Elephant Canyon resulting in significant erosion of the Redwall. Two areas of thinning are along the east flank of the San Rafael Swell reflecting the Emery shelf and in Castle Valley near the Hunter plant (figure 2-1).

The Redwall is exposed in Eardley Canyon where it has been eroded as part of the Emery shelf and highly dolomitized eliminating nearly all porosity. Doelling and others (2015) described an incomplete section (105 feet) of Redwall Limestone in Eardley Canyon as light-gray to pink limestone, dolomite, and chert; locally brecciated into large angular fragments. The nearest well is the T P Utah No. 27-1 well (SENE section 7, T. 23 S., R. 13 E., SLBL&M) which encountered less than 700 feet of Redwall (Morgan and Waanders, 2013). Few wells have been drilled to the Redwall between Castle Valley and Eardley Canyon, and as a result, we cannot determine if the thinning in Castle Valley represents a separate paleohigh on the Emery shelf or if the Redwall continuously thins from Eardly Canyon to Castle Valley.

Drill depths to the Redwall Limestone in the study areas range from more than 16,000 feet (figure 2-2) to exposure at the surface in Eardley Canyon (Doelling and others, 2015). The top of the Redwall is modeled to be less than 7500 feet deep at the Hunter Power Plant, about 11,000 feet deep at proposed Hunter No. 3 location, and about 12,600 feet at the proposed Drunkards Wash No. 1 location. The Redwall is about 400 feet thick at the Hunter Power Plant and 500 feet thick at Hunter No. 3 well (figure 2-1). There is not sufficient well control to accurately predict the thickness of the Redwall at Drunkards Wash No. 1 location.

The Redwall Limestone has good reservoir quality in local areas, such as Lisbon oil field in the Paradox Basin to the southeast, but regionally it is often low in porosity and permeability. Based on available well logs, the Redwall in Castle Valley is thin, lacks porosity, and is not a potential CO_2 storage reservoir. The overlying seal is the Permian Elephant Canyon Formation consisting of dolomite, dolomitic sandstone, red fine-grained sandstone, conglomerate, and limestone (Doelling and others, 2015). Thus, the Permian Elephant Canyon is a poor-quality seal.

Permian White Rim Sandstone

The Permian White Rim Sandstone crops out in small washes and major canyons along the axis of the San Rafael Swell and near the steep east flank (figures 1-2 and 1-3). It is mapped as the Coconino or Cedar Mesa Sandstone in some older publications. In major exposures, the White Rim is 500 to 950 feet thick and consists entirely of sandstone. The sandstone is composed of fine- to coarse-grained, lightly frosted, moderately to well-sorted, subangular to rounded quartz sand cemented with calcite and/or silica (Witkind, 1988; Doelling, 2002; Doelling and Kuehne, 2008). The White Rim is friable to well cemented, and contains intergranular porosity locally filled with dead oil in some units (Doelling and Kuehne, 2008; Harston and others, 2013). In outcrop it forms thick to massive beds containing well-displayed high-angle cross-stratification and some planar bedding. Locally, limonitic or hematitic zones are present as well as irregular red and brown stained patches within sections bleached by possible hydrocarbon migration.

The White Rim Sandstone was deposited mainly in an eolian shoreline environment during Early Permian (Leonardian). The top of the formation is marine (Huntoon and Chan, 1987; Stanesco and others, 2000; Blakey and Ranney, 2008). The White Rim consists of a lower sand-sheet deposit overlain by a thick interval of eolian dune deposits. Sea level rise resulted in the upper part of the White Rim being eroded and reworked. However, some researchers interpreted all or major portions of the White Rim to be marine (Baars and Seager, 1970; Orgill, 1971; Baars, 2010).

Drill depths to the top of the White Rim Sandstone are 10,200 feet at Hunter No. 3 location and 10,100 at Drunkards Wash No. 1 location. A well drilled at the Hunter Power Plant, as originally hoped, would encounter the White Rim at 6700 feet (figure 2-3). The White Rim is projected to be 350 feet thick at Hunter No. 3 location, 500 feet thick at the Hunter Power Plant, and up to 700 feet thick at Drunkards Wash No. 1 location (figure 2-4). Note that figure 2-4 shows what the thickness of the White Rim was across the San Rafael Swell where is has since been removed by uplift and erosion.

Lower Jurassic Navajo Sandstone

The Lower Jurassic Navajo Sandstone and equivalent formations were deposited throughout most of Utah and neighboring states of Wyoming, Colorado, New Mexico, Arizona and Nevada. The Navajo with its spectacular cross-stratification is perhaps the most well-known formation in Utah, where it forms the magnificent cliffs and canyons in Zion and other parks in the southern part of the state. Navajo outcrops in the San Rafael Swell are just as outstanding, where they are displayed as rounded cliffs, alcoves, domes, and knobs exposed along the flanks of the San Rafael Swell and often used to define the geographic boundary of the Swell (figure 1-2). The Navajo also serves as an excellent outcrop analog for hydrocarbon reservoirs and has been used in past CO_2 sequestration models (Allis and others, 2002, 2003; White and others, 2001, 2003).

The Navajo Sandstone ranges in thickness from 400 to 1000 feet in outcrops in the San Rafael Swell. To the east of the San Rafael Swell, the Navajo Sandstone pinches out at the erg margin (Blakey, 1994; Parrish and Falcon-Lang, 2007). To the west near Zion National Park, the Navajo erg thickens where there was the greatest accommodation during deposition into a foreland-arc basin (Gregory, 1950; Peterson and Pipiringos, 1979; Blakey, 2008). The Navajo near Zion consists of sandstone that has likely been bleached by iron-reducing hydrocarbons, weak acids, or hydrogen sulfide (Witkind, 1988; Chan and others, 2000; Chan and Parry, 2002; Doelling, 2002); it also contains subordinate carbonates. The sandstone beds are friable and composed of clean, fine- to medium-grained, frosted, subrounded to subangular, moderately to well-sorted quartz sand with minor amounts of feldspar and scattered heavy mineral grains. Cementation is calcareous or siliceous with minor iron oxides. Sedimentary structures include sets of large, high-angle trough cross-stratification as well as planar or wedge-planar cross-stratification; bedding is thick to massive. Contorted bedding and soft-sediment deformation, wind ripples, and small-scale trough cross-stratification are additionally abundant. Dune facies from the crest (brink point) to the toe of the dune slipface consist of (1) thin, graded, tabular grainfall laminae (rarely preserved), (2) thick, subgraded avalanche laminae, and (3) thin, tightly packed, reworked ripple strata at the dune toe. Massive, homogenous beds having no distinct sedimentary structures or laminations are also recognized in the Navajo and were probably formed by water-saturated sand. Laminated, thin-bedded carbonate units consist of sandy microbial (algal) boundstone and wackestone composed of limestone or dolomitic limestone.

In Early Jurassic time, Utah had an arid climate and lay 15º north of the equator (Hintze and Kowallis, 2009). The Navajo Sandstone and age-equivalent rocks were deposited in an extensive erg, which extended from present-day Wyoming to Arizona, and was comparable to the Sahara in North Africa or the Alashan area of the Gobi Desert in northern China. The eolian deposits included dunes, interdunes, and sand sheets. Paleowind direction was dominantly from the north and northwest (Peterson, 1988). In addition, the Navajo erg system included interdune playas and oases.

Dune facies are laterally and vertically extensive in the Colorado Plateau and San Rafael Swell region and have excellent reservoir properties. The Navajo Sandstone outcrop can be divided into informal upper and lower members, which are dominantly highly porous dune facies with few interdunal deposits, and a middle member which is dominantly lower porosity interdunal facies with interbedded dune facies. This division was carried into the subsurface using gamma-ray and porosity logs to define the members, porosity intervals, and lateral distribution as displayed well-log cross section through the study sites (figure 2-5). Evaluation of the Navajo Sandstone with the Carmel Formation as an overlying seal determined that the Navajo was a high-quality potential storage reservoir. Navajo properties were mapped regionally and then more detailed reservoir mapping was conducted in the two areas of interest: primary Hunter site and secondary Drunkards Wash site (figure 1-2). A major concern with the Navajo was the close proximity of the outcrop to the Hunter plant. As a result, an injection location west and down dip from the Hunter plant was selected.

Drill depths to the Navajo Sandstone in the study areas range from 1500 to 13,000 feet within the Hunter site and 3500 to 10,000 feet within the Drunkards Wash site, deepening to the northwest and west, respectively, and shallowing rapidly to southeast towards the surface exposure (figure 2-6). Drill depths to the top of the Navajo are projected to be 7600 feet at Hunter 3 and 7200 feet at Drunkards Wash No. 1. Regional subsurface structural mapping of the Navajo, based on limited well control, shows relatively gentle dip in a northwest direction (figure 2-7). No faults are indicated in either the Hunter or Drunkards Wash project CO_2 injection sites (figure 2-7); there are some Quaternary normal faults in the westernmost part of the Hunter site but they may not be present at depth in the Navajo. Note that figure 2-7 shows what the structural elevation would be of the Navajo across the San Rafael Swell where it has been removed by uplift and erosion.

Well-log correlations show the Navajo Sandstone is thick and highly porous throughout the Castle Valley area (figure 2-5). Regionally, the gross thickness Navajo Sandstone thins from southwest to northeast through the Castle Valley area and is about 400 to 450 feet thick at Hunter No. 3 and 300 feet thick at Drunkards Wash No. 1 locations (figure 2-8). As a result, net reservoir thickness thins from the Hunter No. 3 location to the Drunkards Wash No. 1 location. Some thickening of the net reservoir is mapped from west-northwest to east-southeast (updip direction) showing some diagenetic effect related to the shallowing depths. Note that figure 2-8 shows what the thickness of the Navajo was across the San Rafael Swell where is has since been removed by uplift and erosion.

The UGS has only one well core of the Navajo Sandstone in central Utah: the Wolverine Gas & Oil Corp. Federal No. 17-3 well (sec. 17, T. 23 S., R. 1 W., SLBL&M, Sevier County) from Covenant oil field about 45 miles southwest of the Hunter site. Based on porosity and permeability data from the 17-3 core, we are confident that 12% or more porosity will have sufficient permeability to be a quality reservoir. Good quality reservoir may exist at 10% or even as low as 8% porosity, but the core does not have sufficient data at lower porosities to make a reliable determination. Therefore, 12% or more porosity was used as the lower limit to be a good quality reservoir.

Density porosity from upper, middle, and lower members of the Navajo Sandstone was sorted and feet of porosity were tabulated. We assumed that the higher porosity beds are dunes and the lower porosity beds are interdune. The feet of porosity data were mapped at 12% or more porosity, 16% or more porosity and 20% or more porosity for the gross Navajo Sandstone and for each of the three members in the Navajo, to show the distribution of net reservoir in the two sites. The Hunter 3 location has 300 to 400 feet net reservoir at 12% or more porosity whereas the Drunkards Wash site has 150 to 200 feet of net reservoir (figure 2-9A). The Hunter site has 200 to 300 feet of reservoir with 16% or more porosity; the Drunkards Wash site has 80 to 120 feet (figure 2-9B). At 20% or more porosity the Hunter site has 100 to 150 feet and the Drunkards Wash site has 20 to 50 feet (figure 2-9C). Feet of porosity at 12% or more, 16% or more, and 20% or more for each of the three members (upper, middle, and lower) has the same distribution pattern as the net reservoir for the total Navajo (figures 2-10 through 2-12). The upper Navajo is better developed at the Hunter site than the Drunkards Wash site whereas the lower Navajo is about equally developed at both locations. The middle member is defined by low porosity and therefore is mostly a poor reservoir at both locations.

Upper Cretaceous Ferron Sandstone, Mancos Shale

The Upper Cretaceous (Turonian to Coniacian) Ferron Sandstone Member of the Mancos Shale was deposited in a wave-influenced, fluvial-deltaic environment. It reflects a balance between changing sediment supply from the advancing Sevier orogenic belt in western Utah and changes in accommodation space resulting from transgressions and regressions of the Cretaceous Interior Seaway in eastern Utah. The Ferron is one of the most studied units in the San Rafael Swell (described in Chidsey and others, 2004). Along the west flank of the Swell, the 80-mile-long Ferron outcrop belt of cliffs and side canyons provides a three-dimensional view of vertical and lateral changes in the Ferron's facies and sequence stratigraphy, and, as such, is an excellent analog for fluvial-deltaic oil and gas reservoirs worldwide. In addition, the Ferron produces methane gas from its coal and sandstone beds within the northern Castle Valley and Wasatch Plateau, respectively. The Ferron is exposed along the east side of Castle Valley just east of the Hunter Power Plant (figure 1-2).

The Ferron Sandstone ranges in thickness from 325 to 720 feet on the west flank, 160 feet on the north-plunging nose, and as thin as 60 feet of the east flank of the San Rafael Swell (Witkind, 1988; Weiss and others, 1990; Doelling, 2002, 2004; Hintze and Kowallis, 2009). In the west flank outcrop belt, the Ferron consists of sandstone and siltstone, sandy to black carbonaceous shale, and coal. Sandstone is very fine to medium grained, poor to moderately sorted, subrounded to angular, and cemented with calcite, dolomite, or iron oxide. Bedding in the sandstone is thin or lenticular to massive, forming vertical cliffs, whereas siltstone, shale, and coal create recesses and slopes. Sedimentary structures in sandstone that determine facies include ripples, channel scours, soft-sediment deformation, cross-stratification, and planar beds. Many beds contain rooted zones, a variety of burrows, or intense bioturbation.

Major cliff-forming sandstone units in the Ferron Sandstone are referred to as delta-front units or parasequence sets based on genetically related parasequences within each set, bounded by major flooding surfaces, and paired to coal zones. The Ferron parasequence sets create seaward-stepping, vertically stacked, and landward-stepping stacking patterns (Anderson and

Ryer, 2004). The alluvial to lower delta or coastal plain of the Ferron contained meander belts, swamps and peat bogs, distributary channels, levees, crevasse spays/overbanks, and bays. Sediment supply was high during early Ferron time resulting in fluvial-dominated conditions that created lobate deltas consisting of delta-front deposits, distributary channel, splay complexes, and interdistributary bays. Later, conditions changed to wave-dominated or wave-modified deltaic deposition forming cuspate deltas that grade laterally into strandplains and barrier islands. Facies associated with wave-dominated or wave-modified deltas consist of prodelta deposits; lower, middle, and upper shoreface; foreshore; distributary channels; and distributary-mouth bars. The strandplains and barrier island facies include washover fans, lagoons, bays, and tidal inlets and associated flood-tidal deltas (Ryer and Anderson, 2004).

Drill depth to the top of the Ferron Sandstone is 300 feet at the Hunter Power Plant, 3200 feet at the Buzzard Bench No. 1 (Danish Flat) location and 3000 feet at the Drunkards Wash No. 1 location (figure 2-13). Structural mapping of the Ferron shows relatively the typical gentle dip in a northwest direction (figure 2-14). No faults are indicated in either the Hunter or Drunkards Wash project CO_2 injection sites. Note that figure 2-14 shows what the structural elevation would be of the Ferron across the San Rafael Swell where it has been removed by uplift and erosion. Total structural elevation of the Ferron is about +3500 feet at the Hunter Power Plant and +3600 feet thick at Buzzard Bench No. 1.

Total thickness of the Ferron is 350 feet at the Hunter Power Plant and 250 feet thick at Buzzard Bench No. 1 (figure 2-15). Thickness at the Drunkards Wash 1 site will be about 300 feet. Note that figure 2-15 shows what the thickness of the Ferron was across the San Rafael Swell where is has since been removed by uplift and erosion. As shown, it thins because the Ferron delta did not extend very far east into the Cretaceous Interior Seaway in central Utah.

The thickness from the top of the Ferron Sandstone to the top of the Navajo Sandstone is shown on figure 2-16. This interval is slightly less than 4000 feet at the Hunter Plant, about 4100 feet at the Buzzard Bench No. 1, and 4400 feet at the Drunkards Wash No. 1 locations (figure 2-16). Again, note that figure 2-16 shows what the thickness of this interval was across the San Rafael Swell where it has been removed by uplift and erosion.

KEY SEALS

Permian Kaibab Formation

The Permian Kaibab Formation overlies the White Rim Sandstone. The Kaibab is exposed over a fairly widespread area along the crest of the San Rafael Swell (figure 1-2) where it ranges in thickness from 0 to 85 feet. It consists of dolomite and limestone with some thin sandstone (Doelling and others, 2015). Carbonates range from thin to thick bedded forming step-like cliffs with a blocky weathering character. The Kaibab was deposited on a shallow carbonate shelf as part the great worldwide Permian epicontinental marine transgression (Blakey and Ranney, 2008; Hintze and Kowallis, 2009).

The Kaibab Formation generally has very low porosity and permeability and would be a baffle or seal for the CO_2 injected into the White Rim Sandstone. However, there are a few intervals of vugular porosity with low permeability in the carbonates and in the sandstones that could reserve/hold small amounts of CO_2. As a result, the Kaibab would be both a seal and a good monitoring bed by tracking upward movement of CO_2 into the porous intervals.

Drill depth to the top of the Kaibab Formation is 6500 feet at the Hunter Power Plant, 10,000 feet at Hunter No. 3, and 9900 at Drunkards Wash No. 1 (figure 2-17). The Kaibab reaches a thickness of as much as 260 feet in the subsurface near the west flank of the Swell (Hintze and Kowallis, 2009). Our thickness mapping shows the Kaibab to be about 140 feet thick at the Hunter No. 3 and Drunkards Wash No. 1 locations (figure 2-18), but this is questionable due to the lack of down dip control wells. Again, note that figure 2-18 shows what the thickness of Kaibab was across a relatively small part of the San Rafael Swell where is has since been removed by uplift and erosion. Subtracting the mapped top of the White Rim Sandstone from the top of the Kaibab Formation results in an interval thickness of 200 feet at both locations.

Triassic Moenkopi Formation

The Triassic Moenkopi Formation overlies the Kaibab Formation and provides an additional seal to the White Rim Sandstone. The Moenkopi is widely exposed along the flanks of the San Rafael Swell structure and is divided into four members, which in ascending order are: Black Dragon, Sinbad Limestone, Torrey, and Moody Canyon. Whereas the classic outcrops of the Moenkopi in southern Utah and northern Arizona are chocolate brown, those in the Swell have been bleached to various shades of yellow, possibly by migrating hydrocarbons and iron-reducing groundwater. The Moenkopi Formation contains numerous tar-sand deposits in the channel sandstones. In general, the Moenkopi consists of interbedded sandstone, siltstone, and shale in the upper and lower members and a carbonate in the middle Sinbad Limestone Member. The Sinbad represents a mixed carbonate-siliciclastic cyclic sequence consisting of limestone, dolomitic limestone, and calcareous sandstone with a few shaly siltstone beds.

The Moenkopi Formation was deposited in various shallow-marine and tidal-flat environments. The Sinbad Limestone was deposited in a marine environment, the farthest extent east of a shallow sea that transgressed from the northwest (Blakey and Ranney, 2008; Doelling and others, 2010). Facies include peritidal, offshore, foreshore/shoal, restricted lagoon/backshoal, and tidal channel (Goodspeed and Lucas, 2007).

The Sinbad Limestone has porosity and yielded high flow rates of CO_2 during testing in many of the wells throughout the study area. It represents a good potential monitoring bed, if upward migration of injected CO_2 occurs. The gas saturation within the Sinbad should be easily detected. However, the Sinbad would need to become fully gas charged before significant vertical migration would continue.

Drill depth to the Moenkopi Formation is about 9000 feet at Hunter No. 3 and 8500 feet at Drunkards Wash No. 1 locations (figure 2-19). The formation thins from west to east and is about 1000 feet thick at Hunter No. 3 and 1400 feet thick at Drunkards Wash No. 1 locations (figure 2-20). The Sinbad Limestone Member ranges in thickness from 0 to 150 feet, thickening north, and represents a mixed carbonate-siliciclastic cyclic sequence. The Sinbad is about 150 feet thick at the Hunter No. 3 and Drunkards Wash No. 1 locations (figure 2-21). Again, note that figures 2-20 and 2-21 show what the thicknesses of Moenkopi and Sinbad, respectively, were across a relatively small part of the San Rafael Swell where they have since been removed by uplift and erosion.

Middle Jurassic Carmel Formation

The Middle Jurassic (Bajocian through Callovian in age) Carmel Formation overlies the Navajo Sandstone in most areas of the San Rafael Swell. The Carmel is divided into four members (described in Chapter 4), which in ascending order are the: Co-op Creek Limestone (or equivalent Judd Hollow), Crystal Creek, Paria River, and Winsor. The Carmel ranges from 280 to as much as 1100 feet thick in the San Rafael Swell (Witkind, 1988; Doelling, 2002, 2004; Doelling and Kuehne, 2008). In general, the Carmel consists of interbedded limestone, sandstone, siltstone, mudstone, and most important in terms of its sealing quality—thick beds of gypsum. Sedimentary structures include ripples, low-angle cross-bedding, bioturbation, and mudcracks. The Carmel ranges from thin to thick to massive bedded forming steep slopes and blocky ledges. The various facies of the Carmel depict a range of depositional environments: nearshore intertidal marine, oolitic shoal, restricted shallow marine, tidal flat, and sabkha.

The Carmel Formation serves as the seal for the naturally occurring CO_2 deposit in the Navajo reservoir at Farnham Dome on a subsidiary structure on the north-plunging nose of the Swell (Morgan, 2007). Based on subsurface mapping, the Carmel should provide an excellent seal in the Hunter and Drunkard Wash sites as well.

Drill depth to the Carmel Formation is about 6500 feet at both Hunter No. 3 and Drunkards Wash No. 1 (figure 2-22). The Carmel Formation thickens west towards the Wasatch Plateau forming 1000-foot-thick pods in the Hunter Power Plant and Buzzards Bench No. 1 areas (figure 2-23). Some local thickening is caused by duplex faulting associated with the basal detachment in the region. The Carmel is projected to be 900 feet thick at Hunter No. 3 and 600 feet at Drunkards Wash No. 1 (figure 2-23). As with the other isochore maps, figure 2-23 shows what the thicknesses of Carmel was across the San Rafael Swell where it has been removed by uplift and erosion. The primary seal in the Carmel are the numerous anhydrite beds (figure 2-24). More than 80 feet of total anhydrite has been mapped in the Hunter area (figure 2-25).

CHAPTER 2 FIGURE CAPTIONS

Figure 2-1. Isochore map of the Redwall Limestone. Contour interval 50 feet.

Figure 2-2. Drill-depth map to the top of the Redwall Limestone. Contour interval 500 feet.

Figure 2-3. Drill-depth map to the top of the White Rim Sandstone. Contour interval 500 feet.

Figure 2-4. Isochore map of the White Rim Sandstone. Contour interval 50 feet. Note: the map shows what the thickness would be of the White Rim across the San Rafael Swell where it has been removed by uplift and erosion.

Figure 2-5. South to north gamma-ray and density-porosity log cross section through the Hunter and Drunkards Wash sites showing the upper, middle, and lower Navajo Sandstone.

Figure 2-6. Drill-depth map to the top of the Navajo Sandstone. Contour interval 500 feet.

Figure 2-7. Top of the Navajo Sandstone structure map. Contour interval 500 feet. Note: the map shows what the structural elevation would be of the Navajo across the San Rafael Swell where it has been removed by uplift and erosion.

Figure 2-8. Isochore map of the Navajo Sandstone. Contour interval 100 feet. Note: the map shows what the thickness of the Navajo was across the San Rafael Swell where it has been removed by uplift and erosion.

Figure 2-9. Feet of Navajo Sandstone with (A) 12% or more, (B) 16% or more, and (C) 20% or more density porosity; contour interval 50 feet.

Figure 2-10. Feet of upper Navajo Sandstone with (A) 12% or more, (B) 16% or more, and (C) 20% or more density porosity; contour interval 20 feet.

Figure 2-11. Feet of middle Navajo Sandstone with (A) 12% or more, (B) 16% or more, and (C) 20% or more density porosity; contour interval 20 feet.

Figure 2-12. Feet of lower Navajo Sandstone with (A) 12% or more, (B) 16% or more, and (C) 20% or more density porosity; contour interval 20 feet.

Figure 2-13. Drill-depth map to the top of the Ferron Sandstone. Contour interval 500 feet.

Figure 2-14. Top of the Ferron Sandstone structure map. Contour interval 500 feet. Note: the map shows what the structural elevation would be of the Ferron across the San Rafael Swell where it has been removed by uplift and erosion.

Figure 2-15. Isochore map of the Ferron Sandstone. Contour interval 50 feet. Note: the map shows what the thickness of the Ferron was across the San Rafael Swell where it has been removed by uplift and erosion.

Figure 2-16. Isochore map of the interval thickness between the base of the Ferron Sandstone to the top of the Navajo Sandstone. Contour interval 500 feet. Note: the map shows what the thickness of this interval was across the San Rafael Swell where it has been removed by uplift and erosion.

Figure 2-17. Drill-depth map to the top of the Kaibab Formation. Contour interval 500 feet.

Figure 2-18. Isochore map of the Kaibab Formation. Contour interval 20 feet. Note: the map shows what the thickness would be of the Kaibab across the San Rafael Swell where it has been removed by uplift and erosion.

Figure 2-19. Drill-depth map to the top of the Moenkopi Formation. Contour interval 1000 feet.

Figure 2-20. Isochore map of the Moenkopi Formation. Contour interval 100 feet. Note: the map shows what the thickness would be of the Moenkopi across the San Rafael Swell where it has been removed by uplift and erosion.

Figure 2-21. Isochore map of the Sinbad Limestone Member of the Moenkopi Formation. Contour interval 20 feet. Note: the map shows what the thickness would be of the Sinbad across the San Rafael Swell where it has been removed by uplift and erosion.

Figure 2-22. Drill-depth map to the top of the Carmel Formation. Contour interval 500 feet.

Figure 2-23. Isochore map of the Carmel Formation. Contour interval 100 feet. Note: the map shows what the thickness would be of the Carmel across the San Rafael Swell where it has been removed by uplift and erosion.

Figure 2-24. Gamma-ray and density-porosity log cross section of the Carmel Formation at the Hunter site. The Carmel has numerous anhydrite beds (shown in red) that are laterally extensive. Anhydrite 3 (informal operator designation) is the thickest anhydrite bed.

Figure 2-25. Isochore map of the anhydrite in the Carmel Formation. Contour interval 20 feet. Note: the map shows what the thickness would be of the anhydrite across the San Rafael Swell where it has been removed by uplift and erosion.

Rocky Mountain CarbonSAFE Phase I

Appendix C

Extensional Faulting in the Jurassic Navajo Sandstone at Little Wedge on the Western Flank of the San Rafael Swell and its Potential Impact on CARBON DIOXIDE Storage Reservoirs, Emery and Carbon Counties, Utah

EXTENSIONAL FAULTING IN THE JURASSIC NAVAJO SANDSTONE AT LITTLE WEDGE ON THE WESTERN FLANK OF THE SAN RAFAEL SWELL AND ITS POTENTIAL IMPACT ON CARBON DIOXIDE STORAGE RESERVOIRS, EMERY AND CARBON COUNTIES, UTAH

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INTRODUCTION

The Navajo Sandstone outcrop in the Little Wedge area, which is updip and nearest the Hunter Power Plant, has a system of normal faults and thus was the focus of this part of the project (figure 3-1). The Little Wedge study area is about 12 miles southeast of the Hunter Power Plant in sections 5, 8, and 17, T. 20 S., R. 10 E., SLBL&M, Emery County, Utah (figure 1-2). The San Rafael River cuts through the Navajo Sandstone at Little Wedge, exposing the sandstone east and west of the river (figure 3-1).

The Normal faults at Little Wedge trend about north-south with displacements of a few feet to tens of feet in the Navajo Sandstone. Displacement is generally down to the west; slickensides indicate near vertical movement. Fault planes are polished and crushed sandstone grains with associated deformation bands. Solum and others (2010) describe deformation bands as a zone of localized grain rearrangement (packing geometry, rotation, and sliding) and cataclasis (breaking, spalling, and crushing). Minor amounts of azurite and malachite are present along the faults. There is no evidence of springs associated with the fault system.

The fault plane and associated zones of deformation bands would most likely impede but not fully stop the migration of injected CO_2 in the Navajo Sandstone reservoir. Due to the limited length of individual faults and the fault system, some migration could occur around and in between individual faults with the majority of the CO_2 migrating around the fault system.

FAULTING IN THE SAN RAFAEL SWELL

Our efforts in the Little Wedge area focused on identifying faults, measuring strike and dip with a Brunton compass, and walking along a fault trace whenever possible. Faults were plotted on the U.S. Geological Survey Sids Mountain, Utah, 7.5-minute topographic map and on a Google™ map image and were later plotted in ArcMap. We noted direction of fault movement based on slickensides and mineralization at a few locations. Total stratigraphic displacement was estimated for most of the faults.

Surface faulting in the San Rafael Swell has been mapped by Kent (1956), Witkind (1988), Weiss and others (1990), and Doelling (2002, 2004) (figure 1-2). Three sets of normal faults are mapped: (1) northwest-southeast Paradox Basin and Uncompahgre uplift trend, (2) east-west trend generally parallel to the doubly plunging San Rafael Swell axis, and (3) north-south Basin and Range extensional trend. Faulting at Big Hole was studied by Shipton and others (2002). Iron Wash fault was studied by Richey and Evans (2013). North-south-trending faults at Little Wedge, southeast of the Hunter Power Plant, are the focus of this study.

The northwest-southeast striking faults are found mostly on the east flank of the San Rafael Swell and reflect the structural trend of the Paradox Basin and Uncompahgre uplift. The Iron Wash fault zone is one of the longest northwest-southeast fault zones in the area and is described in detail by Richy and Evans (2013). The east-west striking faults are generally along the north- and south-plunging axis of the San Rafael Swell. The Big Hole fault zone is an example of east-west striking faults and is described in detail by Shipton and others (2002). The north-south striking faults are the most common type along the west flank of the San Rafael Swell and the most likely to be encountered in the subsurface in the Castle Valley area. These faults represent Miocene Basin and Range extension.

FAULTING AT LITTLE WEDGE

The series of north-south normal faults at Little Wedge were mapped by Kent (1956) and later by Witkind (1988). The faults at Little Wedge trend north-south with strikes measured from N. 12º W. to N. 15º E. They dip west from 60º to near vertical; most of the dips measured are in the 75º to 80º range. Slickensides are near vertical with no indication of lateral shear motion. Fault planes consist of polished crushed grains with associated deformation bands.

Typically, a high density of deformation bands occurs near the fault and rapidly decreases in density away from the fault (figures 3-2 and 3-3). Most of the deformation bands are on the upthrown (footwall) side of the fault. The fault system consists of a series of faults with displacement translated from one fault to the next (figure 3-1). Some minor antithetic faults are present (figures 3-4 and 3-5). Displacement ranges from a few feet to an estimated 30 feet (figure 3-6). At Big Hole the deformation bands are limited to the damage zone—the narrow area parallel to the fault and formed under significantly less mean effective stress than in a compressional case (Solum and others, 2010).

Evidence of past or present fluid flow along the faults is rare. Past fluid flow is indicated by iron concretions in a few locations (figure 3-3) and rare deposits of copper minerals. The Sorrel Mule mine (figure 3-7) along the west side of the San Rafael River was discovered by Jack Montis (McClenahan, 1986; referenced in Lipton, 1989). The mine is a single adit 1060 feet in length in the Navajo Sandstone along a fault (Lipton, 1989). Lipton (1989) reports the fault strikes N. 60º E. with vertical to 70º northwest dip but we mapped it as a prominent lineament, not a fault, having no displacement. However, we did find a north-south striking fault associated with the mine (figure 3-1). Lipton (1989) observed iron- and manganese-oxide staining but did not find any copper mineralization. The mine is accessible by canoe or raft along a popular stretch of the San Rafael River and may have been picked clean of any mineral samples. We did not visit the mine but found a vertical shaft, about 6 feet deep, along the same fault but near the top of the Navajo about 200 feet above the river (figure 3-8). We collected small samples containing malachite and azurite from the shaft (figure 3-9). There are no mining adits or shafts along the faults on the east side of the river at Little Wedge, but one sample containing traces of malachite and azurite was collected along one fault.

No evidence of springs were found associated with the faults the Little Wedge area, although we did not visit the fault locations along the river. No springs issue from the Navajo Sandstone at Little Wedge, based on the work by Hood and Patterson (1984) and Doelling (2002), and the Sids Mountain 7.5-minute topographic map. The lack of springs associated with the faults in the Little Wedge area indicates no upward movement of water along the fault system.

Using a tiny permeameter, team members from the University of Utah measured the relative permeability of the fault and the host rock. Hand samples of the fault and the host rock collected from the Little Wedge area were brought back to the Utah Core Research Center (figure 3-10). The samples analyzed indicated a one order of magnitude reduction in permeability between the fault plane and host rock, but these measurements may underestimate the reduction in permeability. The analysis was conducted on a small hand sample and the host rock may have been sufficiently altered, reducing its permeability. Antonellinin and Aydin (1994) found that host rock near deformation bands may have greater cementation due to precipitation resulting from the interaction between fluids contained in the host rock and those contained in the band(s). Shipton (1999) and Shipton and others (2002) studied faulting in the Navajo Sandstone in the Big Hole area near the axis of the San Rafael Swell east of the Little Wedge (figure 1-2). Shipton and others (2002) studied numerous cores drilled through the Big Hole fault that strikes N. 70º E. and dips 64º north and contains numerous associated deformation bands. A probe permeameter showed permeability declining from >2000 to < 0.1 millidarcies (mD); whole core analysis showed >1 mD. Solum and others (2010) reported shear bands in the Big Hole area with a permeability reduction of three to five times that of the underformed Navajo host rock. Zuluaga and others (2016) reported a permeability reduction of two to three orders of magnitude in deformation bands compared to Navajo host rock in the San Rafael Swell. Pitman (1981) and Antonellini and Aydin (1994), working near Moab, Utah, reported that deformation bands reduce the permeability of host rock by about three orders of magnitude on average. However, the slip plane can have more than seven orders of magnitude reduction in permeability compared to unaltered host rock (Antonellini and Aydin, 1994). Flow simulations by Zuluaga and others (2016) show the fault zone does not completely block the flow. Deformation bands with permeability one to two orders of magnitude lower than the host rock had negligible effect on simulated fluid flow (Zuluaga and others, 2016). Assuming a host rock permeability of 100 mD, a three orders of magnitude reduction would result in a fault and associated deformation bands having 0.1 mD. This would greatly impede but not completely stop the migration of CO_2. A CO_2 plume encountering a fault system in the Navajo would be mostly diverted around the fault zone, with some CO_2 migrating around individual faults, and a very small amount would migrate through the fault (figure 3-11).

The Carmel Formation typically forms an eroded dip slope on the Navajo Sandstone in the San Rafael Swell. As a result, outcrops with faults in the Navajo have only a thin veneer of overlying Carmel. We were unable to determine from outcrop if the faults in the Navajo penetrate the entire Carmel or if they die out within the formation. The Carmel in Castle Valley has salt, anhydrite, and numerous shale and siltstone beds, all of which have the potential for plastic deformation instead of brittle fault displacement. Shallow faults above the Carmel may become listric within the Carmel resulting in a deep and shallow set of extensional faults that are not connected (figure 3-12). This plastic deformation would provide an excellent seal preventing upward movement of CO_2 along a fault plane. If the fault continues through the Carmel, the numerous salt and anhydrite beds should still provide an adequate seal preventing upward migration of CO_2.

SUMMARY

The most likely type of faults that will be encountered in Castle Valley near the Hunter and Huntington Power Plants are Basin and Range extensional, normal faults having down-to-the-west displacement. Displacement on most of the faults will likely be on the order of feet to tens of feet. The Little Wedge area is the nearest Navajo Sandstone outcrop updip from the Hunter plant and has several extensional faults that are good analogs to the faulting expected in Castle Valley. The fault system at Little Wedge is a series of north-south faults that translate displacement from one fault to the next. The fault system is less than 2 miles in length and is composed of much shorter individual faults. The fault planes are polished, crushed sandstone grains with a zone of near-parallel deformation bands. The fault planes and damage zones typically have a permeability reduction compared to undamaged host rock of three to four orders of magnitude. As a result, migration of CO_2 up the fault plane is not expected. The faults should impede, but not be a complete barrier to, up-dip migration of CO_2 in the Navajo reservoir. Some CO_2 is expected to migrate around and through the individual faults while the majority of the CO_2 will probably migrate around the fault system.

CHAPTER 3 FIGURE CAPTIONS

Figure 3-1. Faulting at Little Wedge in the Navajo Sandstone and Carmel Formation. The Navajo Sandstone is cut by the San Rafael River at this location. Carmel/Navajo contact drawn using ESRI World Imagery (satellite imagery compiled from numerous sources). Fault displacements are a few feet to a few tens of feet.

Figure 3-2. Examples of fault planes in the Navajo Sandstone at Little Wedge. Fault planes consist of polished crushed grains. Slickensides indicate near-vertical movement.

Figure 3-3. Deformation bands and iron-sandstone concretions associated with faults in the Little Wedge area. The density of the deformation bands and concretions decreases with distance from the fault. Deformation bands are associated with all the faults, but concretions were found at only a few locations.

Figure 3-4. A series of faults in the Navajo Sandstone and overlying Carmel Formation at Little Wedge. (A) Northernmost exposure of faulting in the Navajo, view north. (B) Westernmost fault (left) has reverse motion and is interpreted to be antithetic to the eastern main fault (right). View is to the north; all three faults join up to become a single fault to the south (figure 3-1). U = upthrown and D = downthrown side of the faults.

Figure 3-5. View of the side of a small canyon (looking northwest) showing minor reverse fault with a few feet of displacement in the Navajo Sandstone and overlying Carmel Formation. Fault may be antithetic to the larger normal fault to the east (right) not shown.

Figure 3-6. View east across the fault on the west side of the San Rafael River, same location as the mine shaft (figures 3-1 and 3-8). Displacement at this location is about 30 feet down to the west.

Figure 3-7. View south from the east side of the San Rafael River looking at the Sorrel Mule mine. The abandoned mine is a 1060-foot adit reported to have found minor amounts of copper. A 6-foot-deep shaft on top of the Navajo Sandstone along the same fault shows some minor copper mineralization. The fault on the east side of the river (foreground) does not appear to be directly connected to the faults on the west side of the river. U = upthrown and D = downthrown side of the faults.

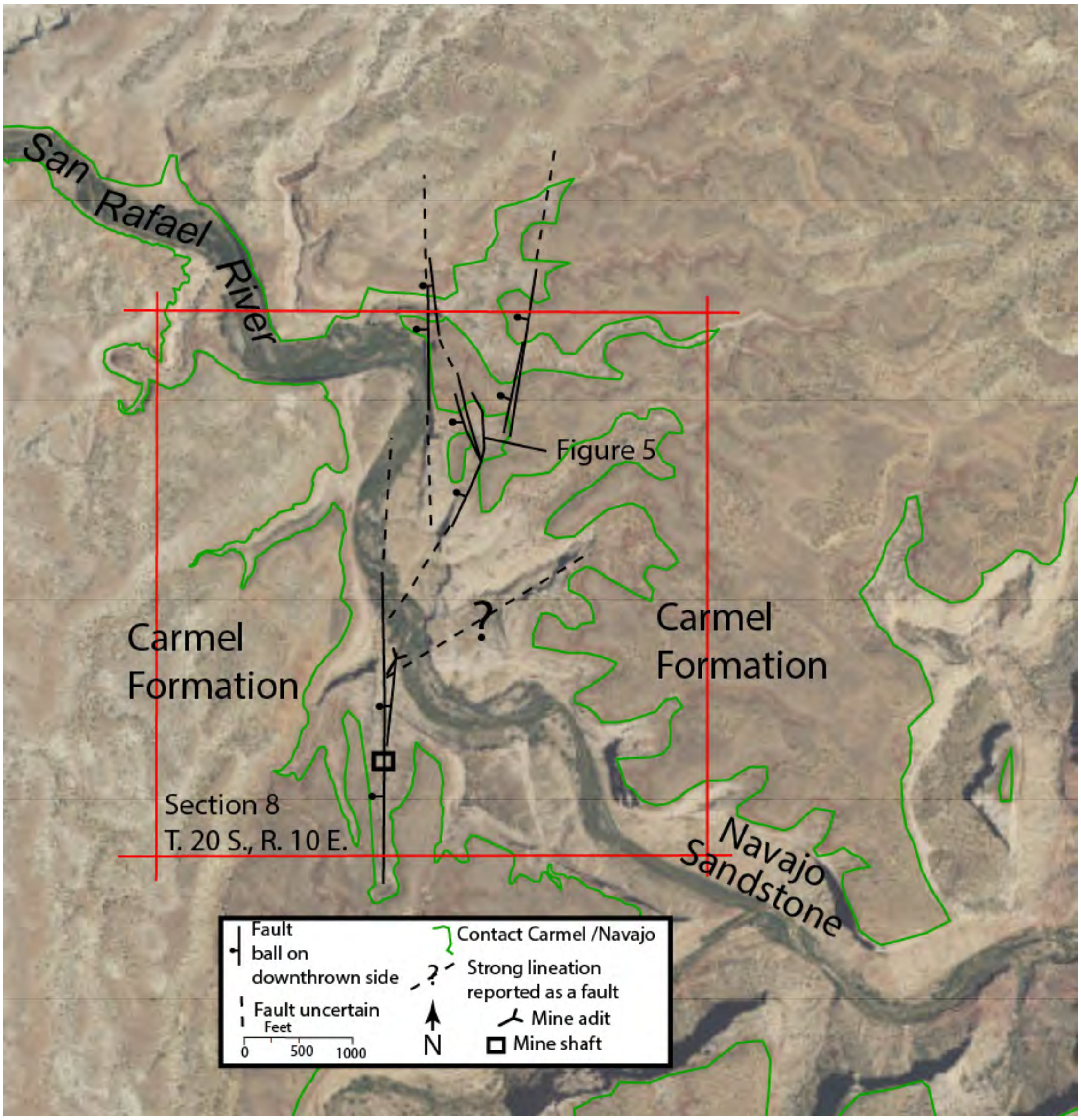
Figure 3-8. View to the north on the west side of the San Rafael River. The shaft is dug along the fault contact between the Navajo Sandstone and Carmel Formation. This is the same fault that is in the Sorrel Mule mine along the San Rafael River (see figures 3-1 and 3-7).

Figure 3-9. Samples of malachite and azurite collected from the shaft along the fault on the west side of the San Rafael River (see figure 3-8).

Figure 3-10. Sample collected from the fault at Little Wedge on the east side of the San Rafael River. Sample contains slickensides and deformation bands in the Navajo Sandstone. The deformation bands and host rock are from the footwall of the fault.

Figure 3-11. A conceptual model showing the up-dip migration of CO_2 around and through faults that might be encountered in the Navajo Sandstone in Castle Valley. Fault pattern based on faults mapped at Little Wedge. Arrow thickness represents an estimated percent of the total CO_2. Most of the CO_2 will migrate around the fault system which typically has a limited length, some CO_2 will migrate around the individual faults, and a very small amount will migrate through the faults.

Figure 3-12. Examples of possible extensional (normal) faulting in the Castle Valley area. (A) Normal fault probably originating in the basement, with displacement in the Navajo Sandstone extending upward through shallow formations. (B) Normal fault in Navajo and deeper formations dies out upward and transitions to ductile folding within the evaporite facies of the Carmel Formation. Shallow extension dies out downward in the evaporite facies. The shallow and deep faults are related but not directly connected. (C) Similar to B but extension in the shallow formations is accommodated by a normal fault unrelated to the deeper normal fault. Also shown is duplex faulting of the basal detachment within the Carmel (not discussed in this report) resulting in shallow structures such as the Huntington anticline. These shallow structures are not associated with faulting in the Navajo.



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(A)

(B)

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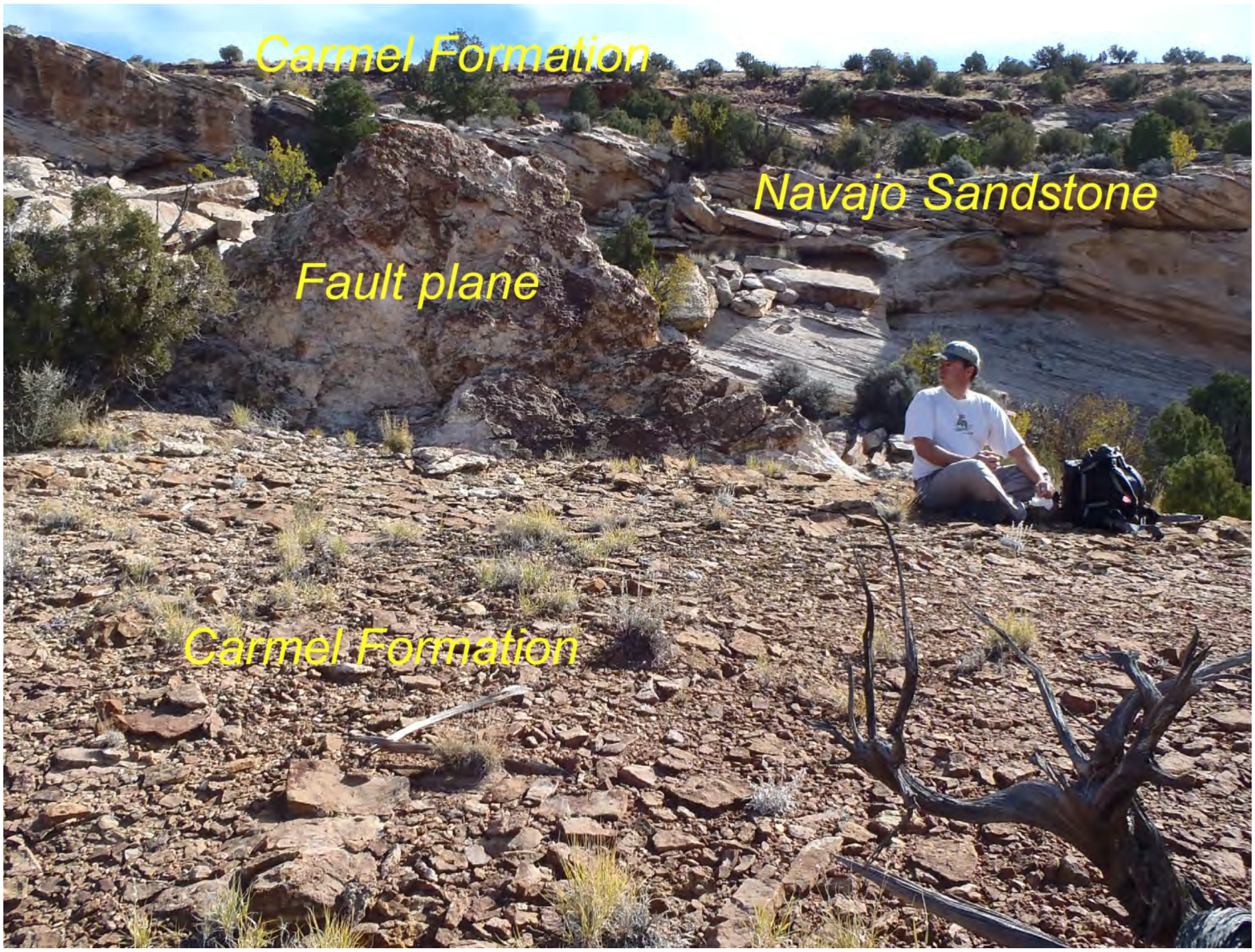

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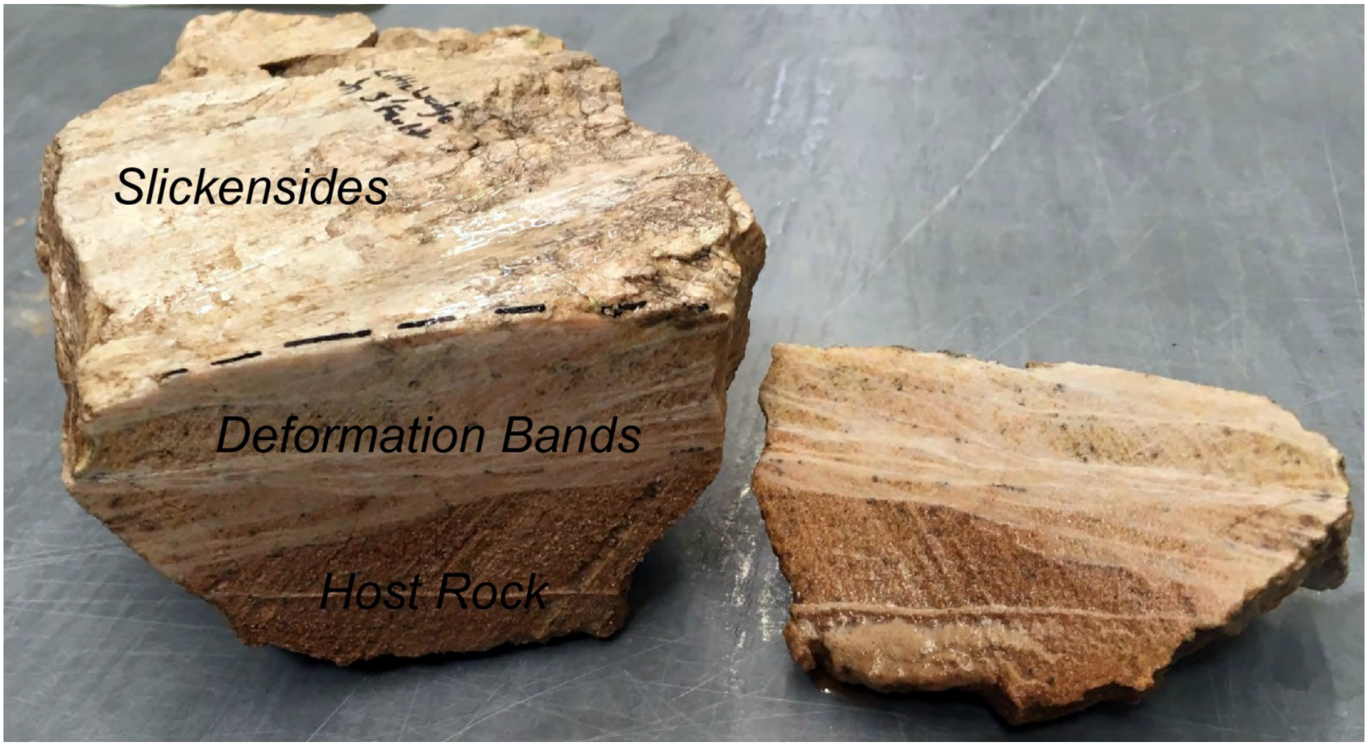

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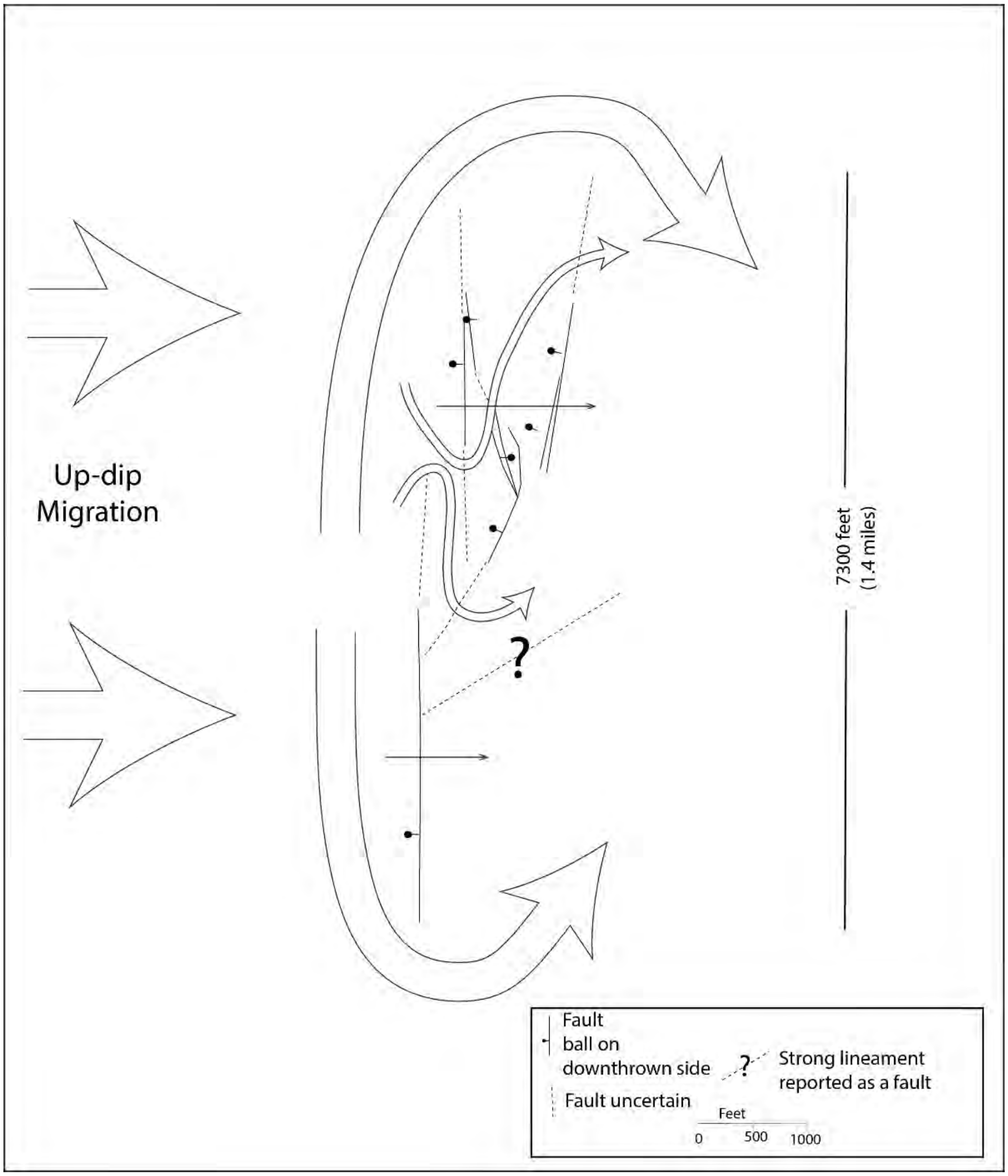

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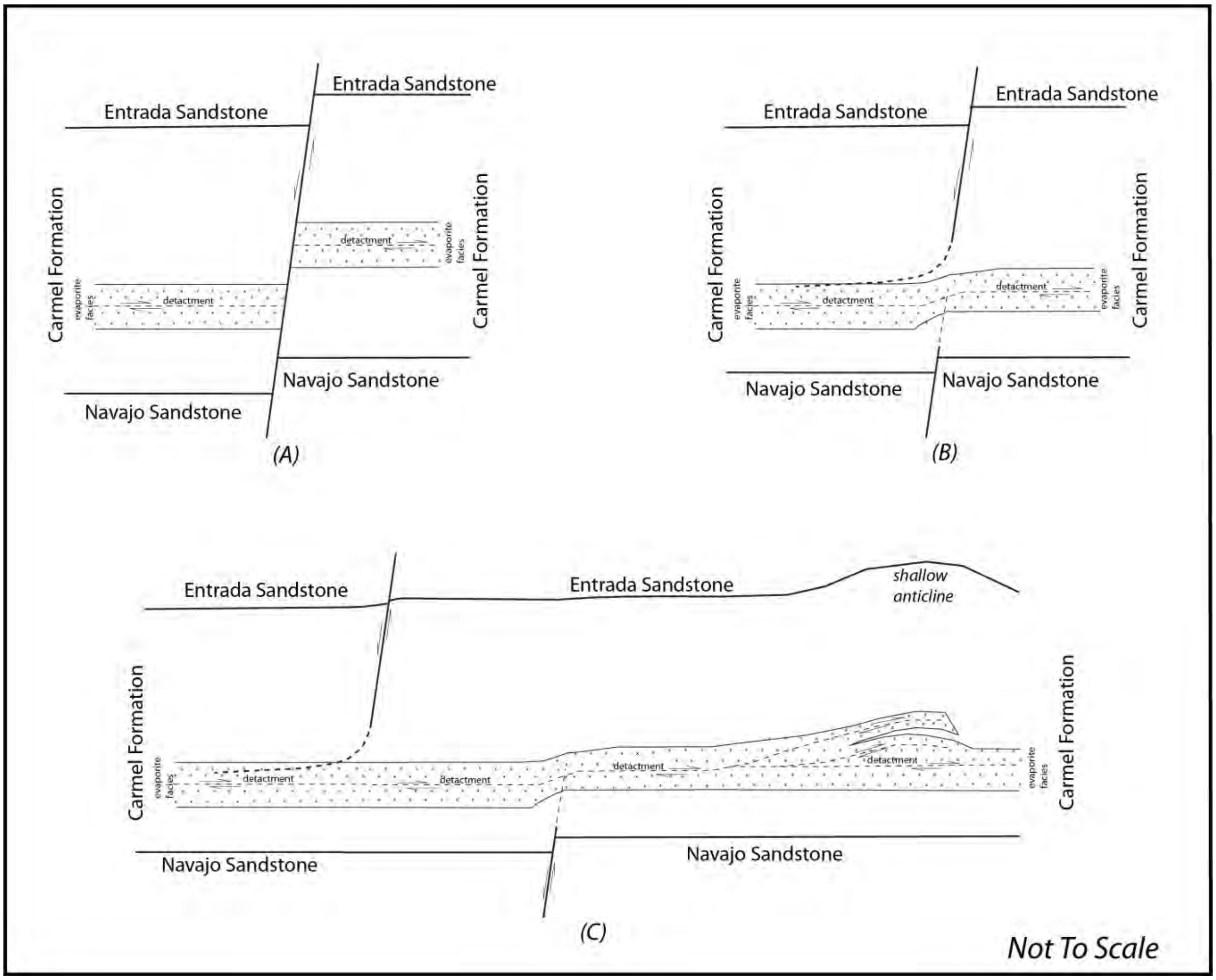

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Appendix D

SEDIMENTOLOGY, DIAGENESIS, AND RESERVOIR CHARACTERIZATION OF THE PERMIAN WHITE RIM SANDSTONE—PROSPECTIVE STORAGE EFFICACY FOR CARBON CAPTURE AND SEQUESTRATION

SEDIMENTOLOGY, DIAGENESIS, AND RESERVOIR CHARACTERIZATION OF THE PERMIAN WHITE RIM SANDSTONE—PROSPECTIVE STORAGE EFFICACY FOR CARBON CAPTURE AND SEQUESTRATION

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INTRODUCTION

Geologic reservoir characterization studies commonly focus on the reservoir size, structural geometry, rock properties (e.g., porosity and permeability), fluid flow paths, and reservoir heterogeneities, as well as describing the overlying sealing units (White and others, 2005; Boot-Handford and others, 2014; Niu and others, 2014). The Permian White Rim Sandstone is a CO_2-bearing reservoir that is 450 m thick and overlain by the Permian Kaibab Limestone and Triassic Moenkopi Formation that could serve as reasonable seals. This chapter has two major research goals: (1) characterize the Permian White Rim Sandstone reservoir (e.g., stratigraphic architecture, facies, and diagenesis), and (2) provide input parameters for modeling work (e.g., rock properties). These goals lead to a set of driving research questions. (1) How do stratigraphic architecture and sedimentary textures/structures affect fluid flow through the reservoir sandstones? (2) How has diagenesis affected reservoir properties (porosity/permeability), and are there any stratigraphic or spatial distributions to these effects? Collectively, these questions aim to assess the reservoir quality and preferential flow pathways of the White Rim, with applications to stratigraphically equivalent subsurface reservoir units via a potential injection well west of the San Rafael Swell near the Hunter and Huntington Power Plants.

PERMIAN WHITE RIM SANDSTONE

Past petroleum- and diagenetic-focused studies have observed multiple fluid-flow episodes through the eolian Permian White Rim Sandstone in the Canyonlands National Park region to the southeast. Although the exact timing and sources for each episode differ slightly between studies (Schenk, 1989; Hansley, 1995; Gorenc and Chan, 2015), most report several episodes of fluid flow with iron oxide, pyrite, and hydrocarbon diagenetic phases. Paleoenvironmental-focused studies record two major stratigraphic intervals in the White Rim: (1) a lower eolian unit characterized by wind ripple and grainflow laminae and large-scale, cross-stratified sandstones, and (2) an upper reworked unit characterized by oscillation (wave) ripples, soft-sediment deformation and massive beds, and marine trace fossils (Huntoon and Chan, 1987; Steele, 1987; Huntoon and Kamola, 1988; Kamola and Huntoon, 1994). Our study presents both the diagenetic and sedimentological history of the White Rim Sandstone in the relatively understudied San Rafael Swell outside of the Canyonlands region.

Study Area

The main study areas for this project occur on the more gently dipping western and northwestern flank of the San Rafael Swell at Sids Draw (field site A), Sids Reservoir (field site B), and Black Box trailhead (field site C) (figure 4-1). We chose several representative sites that adequately demonstrate the variability within the Upper Permian to Lower Triassic section. These sites are located to the west of the study done by Harston and others (2013) in the eastern portion of the San Rafael Swell. Because the core of the anticline is eroded, injection into the White Rim would rely on solubility/residual trapping (i.e., the CO_2 dissolves into the formation water as the plume spreads out over a large geographic area) or mineralization instead of structural trapping (White and others, 2005). The outcrop locations were compared to the Hamon USA No. 8-1 (SENW section 8, T. 19 S., R. 9 E., SLBL&M, Emery County) and Tully No. 16-9-36D White Rim Sandstone cores ~33 km and ~50 km northwest of the study sites, respectively. These cores provide examples of the potential reservoir quality of the White Rim Sandstone in the general area of a prospective injection well and at the prospective injection depths. The White Rim core interval in the Hamon USA No. 8-1 well is 1561–1577 m and in the Tully No. 16-9-36D well is 2230–2243 m.

Depositional Features

The White Rim Sandstone has seven individual lithofacies in the study interval (figure 4-2, table 4-1), based on mineralogy, grain-size and texture, sedimentary structures, and ichnology: (1) grain flow facies, (2) wind ripple facies, (3) ripple laminated facies, (4) soft-sediment deformation (SSD) facies, (5) symmetrically ripped facies, (6) bioturbated facies, and (7) massive facies. These lithofacies are grouped into facies associations (A–B), which correspond to distinct stratigraphic changes in facies (table 4-1).

The White Rim Sandstone has two major units each defined by a separate facies association (figure 4-3). The lower eolian unit, which comprises the majority of the White Rim, is characterized by facies association A with nested sets of bounding surfaces. The upper reworked unit (4–10 m thick), characterized by facies association B, exhibits a distinct, repeated sequence of facies at all three field sites (figure 4-3). The lower White Rim unit (facies association A) is characterized by cross-bedded dm- to m-scale trough cross-bedded sandstone with internal grain flow and wind ripple laminae. The internal grain flow facies (also called avalanche tongues) has thick, cm-scale, wedge shaped, internally massive, fine- to lower medium-grained beds. The wind ripple facies has thin, mm-scale, parallel, "pin stripe" inversely graded, translatent laminae. These laminae are more common towards the base of the dune sets. The ripple laminated facies is relatively thin (<10 cm), fine-grained, and ripple laminated. The ripple laminated facies has mm-scale, sinusoidal laminae with each lamination eroding portions of the previous one (i.e., "traditional" ripple laminations).

The cross-bedded internal grain flow and wind ripple facies are separated by three nested orders of bounding surfaces that repeat throughout the section (figure 4-4). The most laterally extensive and "highest order" surfaces are the deflation surfaces, also termed interdune migration surfaces (Kocurek, 1988), and are equivalent to the 1st order bounding surfaces described by

Brookfield (1977). The deflation surfaces are relatively flat (after removal of structural dip), laterally extensive (100s of meters), truncate cross-bed sets and internal bounding surfaces, and have a vertical spacing of meters to 10s of meters. The rippled laminated facies commonly occurs at deflation bounding surfaces. Cross-bed set surfaces, equivalent to 2nd order bounding surfaces described by Brookfield (1977) occur between cross-bed sets (i.e., dune set boundaries), and typically extend for meters to 10s of meters with vertical spacings of 10s of centimeters to meters. Internal laminae surfaces, the "lowest" (nested) order bounding surfaces, occur between individual wind ripple and grainflow laminae and/or beds.

The upper unit (~4- to 10-m thick) of the White Rim Sandstone (facies association B) exhibits a different set of facies and ichnology compared to the lower unit. All three study sites show a similar stratigraphic progression of facies. In ascending order they are: (1) soft-sediment deformation (SSD) facies, (2) symmetrically rippled facies, (3) bioturbated facies (dominantly horizontal burrows), and (4) bioturbated facies (dominantly vertical burrows). Although the expression and thicknesses of each facies changes slightly between locations, the same general progression exists at all sites. The SSD facies encompasses several expressions of soft-sediment deformation including deformed/crinkled bedding and clastic pipes, which are a cylindrical type of injectite. At field site B (Sids Reservoir) the transition between the upper and lower unit is marked by clastic pipe eruption structures (i.e., the eruption horizon coincides with the transition) (figure 4-5). Within the bioturbation facies, the bioturbation index increases upward in the section and includes beds with bioturbation indices of 1–6 (i.e., slightly or sparsely bioturbated to completely bioturbated or homogenization of the sediment) (Taylor and Goldring, 1993). The lower beds have mostly horizontal traces such as *Thalassinoides* and *Planolites.* The overlying beds are dominated by vertically oriented *Ophiomorpha* trace fossils followed by beds containing other vertical traces such as *Skolithos*. The final beds have a mix of horizontal and vertical traces along with ripple laminated beds.

Diagenesis

Petrography

White Rim Sandstone lithofacies in outcrop are compositionally and textural mature, well-rounded, well- to very well-sorted, fine-grained quartz arenites. Grain size varies from very fine to lower medium-grained sand. Very fine grained sand is concentrated in the wind ripple laminae, with lower medium-grained sand concentrated in the grain flow laminae or beds. Thin sections from outcrop samples show multiple diagenetic stages and phases including: (1) initial quartz overgrowth cements, (2) subsequent carbonate cementation, (3) iron oxide precipitation, and, in some cases, (4) oil staining. All outcrop samples regardless of facies or stratigraphic position experienced initial quartz overgrowth cementation. Very fine grained carbonate cements commonly form a coating on the quartz grains and previous quartz cements (figure 4-6A through 4-6D). In some cases, the very fine grained calcite cements are intermixed with iron oxide cements. The cross-cutting relationships between these two phases are typically unclear, but in places where the cross-cutting relationships are distinct, the iron oxide precipitation occurred after the carbonate cementation. Examination of outcrop samples does not indicate that there were previously precipitated carbonate cements that might have subsequently dissolved. Oil staining is rare in the White Rim Sandstone at these San Rafael Swell the field sites (restricted to a <1-m-thick interval).

White Rim Sandstone core samples are texturally and compositionally similar to all of the outcrop samples. However, the core samples have a distinctly different set of diagenetic characteristics. Core samples show stages of (1) initial quartz overgrowth cements, and (2) subsequent carbonate cementation (figure 4-6E through 4-6H). The core samples have undergone significantly more compaction (shown by more long and concavo-convex grain contacts) which greatly reduced the primary porosity in the sandstones shown on the photomicrographs. The porosity was further destroyed by quartz overgrowth cements and a later stage of patchy, large, pore-filling calcite cement that nearly eliminated any remaining primary porosity (figure 4-6E through 4-6H).

Visible and Near Infrared Spectroscopy

Visible and near infrared spectroscopy (VNIR) of both outcrop and core samples aided the assessment of diagenesis on reservoir properties. VNIR is an ideal tool to determine composition of diagenetic minerals in sandstones because many of the dominant grain mineralogies such as quartz and feldspar do not have major absorption peaks within the target wavelengths (300–2800 nanometers [nm]). In contrast, common diagenetic minerals such as iron oxides, carbonates, sulfates, and clay minerals all have major absorption peaks within this range. Therefore, absorption peaks between 300–2800 nm commonly represent different diagenetic phases in quartz arenites like the White Rim Sandstone.

Spectrographic information confirms the diagenetic phases observed in petrography, and further indicates additional clay mineralogies, although it could not be determined if the clays are diagenetic pore filling cements or a result of the degradation of feldspars. VNIR data from 58 White Rim Sandstone outcrop samples show a single carbonate phase, multiple iron oxides phases, and at least one clay mineral phase (figure 4-7). Consistent absorption peaks across samples at ~2340 nm indicate the presence of calcite (no dolomite peaks were observed). The White Rim contains only a small percentage of patchy iron oxide cements as indicated by field and petrographic observations. However, multiple samples contain two iron oxide phases: (1) hematite and (2) goethite. Samples have absorption peaks at ~383, ~477, ~508, ~683, and ~897 nm indicating hematite and goethite iron oxide phases. In addition to carbonate and iron oxide phases there is at least one clay mineral phase with a major absorption peak at ~2201 nm. Core samples (n = 76) have absorption peaks for calcite and a clay mineral but lack absorption peaks for any iron oxide phases.

Reservoir Properties

The White Rim Sandstone has permeability values that range from 10s to 100s of mD, but not exceeding 500 mD. Although all facies described in the White Rim are compositionally and texturally similar there are significant permeability differences related to each facies (figure 4-8). Grainflow laminae and/or beds have the highest median and average permeability of all facies (177 mD and 190 mD, respectively). In contrast, wind ripple laminae have the lowest median and average permeability of all facies (49 mD and 60 mD, respectively). Between these two end members lies the bioturbated facies (median permeability of 131 mD), the ripple laminated facies (median permeability of 93 mD), the SSD (e.g., deformed cross-beds) facies (median permeability of 87 mD), and the massive facies (median permeability of 64 mD). The rippled laminated facies, the SSD facies, and the massive facies have few discrete beds throughout the section and are under sampled relative to the grain flow, wind ripple, and bioturbated facies. Therefore, the ripple laminated, SSD, and massive facies permeability values should be taken as rough approximates instead of statistically significant assemblages. Even with differentiation between facies, all recorded outcrop measurements, with the exception of three data points, have reservoir grade permeabilities (defined by this study as >25 mD). However, these outcrop measurements differ significantly from those taken from the White Rim core. Core measurements of permeability are <0.01 mD (the detection limit for the instrument) across all facies.

Most outcrop samples have porosity values between 10% and 20% with several outliers that fall into the 5%-25% range (data from Harston and others, 2013, petrographic and porosity/permeability plug analysis). Internally, there is no significant difference in values between Harston and others' (2013) eolian dune and interdune facies (equivalent to facies association A) and the reworked facies (equivalent to facies association B). In contrast, thin sections from the Hamon No. 8-1 core show no discernable porosity across all samples. Primary porosity was nearly completely destroyed via compaction, quartz overgrowth cements, and subsequent calcite cementation.

Interpretations

Depositional Environments

The grain flow, wind ripple, and ripple laminated facies (facies association A) indicate an eolian environment for the lower unit and the majority of the White Rim section. The dm- to m-scale trough cross beds likely represent small barchanoid dunes in a coastal dune field (dominant paleocurrent direction to the southwest). The ripple laminated facies is the result of interdunes that coincided with the laterally extensive deflation surfaces (i.e., 1st order bounding surfaces). Other studies interpret a variety of interdune facies that occur almost exclusively at deflation surfaces (Kocurek, 1988, 1991; Parrish and others, 2017). The transition to the upper unit (facies association B) with subaqueously deposited symmetrical ripples, SSD, and burrows indicates a marine transgression. The SSD and injectite eruptions were most likely triggered by (1) the rapid increase in pore pressure, (2) destabilization of the newly saturated, high-porosity sands by strong ground motion (i.e., earthquakes), or (3) both in combination. The presence of wave ripples further confirms the marine interpretation for the upper unit and indicates a period of stabilization after the SSD and prior to the establishment of biological communities. The overlying highly bioturbated beds follow a classic shoreface sequence beginning with dominantly horizontal burrows such as *Thalassinoides* and *Planolites* in the lower shoreface and progressing to dominantly vertical burrows such as *Ophiomorpha* and *Skolithos* in the upper shoreface. Finally, the eolian system was fully transgressed resulting in the deposition of marine carbonates in the Permian Kaibab sea.

Diagenetic History

The White Rim Sandstone outcrop and core samples likely experienced distinctly different burial and fluid-flow histories. All outcrop facies show initial quartz overgrowth cements with some samples showing subsequent carbonate and iron oxide precipitation. A small interval of the White Rim (<1 m) and beds stratigraphically above the White Rim exhibit oil staining. Although the relative timing of the outcrop diagenetic phases is established by petrographic relationships, their absolute timing proves more difficult in the absence of any definitive makers (e.g., specific temperatures or pressures).

The White Rim Sandstone cores near the prospective injection site exhibit a different degree of diagenesis. Increased compaction and extensive initial quartz overgrowth cements across all core samples removed nearly all of the primary porosity. Any remaining porosity was filled with subsequent calcite cementation. The large, pore-filling cements from the core contrast with the "fine-grained" rim-forming calcite of the outcrop samples. Additionally, there is no evidence of secondary dissolution of previously precipitated calcite and the creation of secondary porosity at the outcrop surface. The different styles of carbonate cementation, different degree of compaction, and absence of iron oxide and hydrocarbon diagenetic phases in the core indicate that the outcrop and core samples likely experienced different burial and fluid flow histories. This differing diagenetic history results in high quality reservoir properties in outcrop and poor reservoir properties in the core, if these results are representative of the majority of the subsurface White Rim. With the current data, the prospective injection site near the power plants appears as though it would likely have poor reservoir quality and be an inadequate storage reservoir.

Discussion and Reservoir Characterization

The White Rim Sandstone has nested levels of heterogeneities related to nested scales of bounding surfaces. The permeability differences in facies correspond largely to the number and relative spacing of horizontally or obliquely oriented, internal laminae or bounding surfaces, which baffle fluid flow. Consequently, eolian units have a greater degree of horizontal permeability (Kh) relative to their vertical permeability (Kv) (Goggin and others, 1988). Although facies and bounding surfaces are the primary control on porosity and permeability, all facies in outcrop have reservoir quality permeability and porosity values. Therefore, modeling and reservoir characterization of the White Rim does not rely on reservoir and non-reservoir distinctions and architecture, and instead necessitates the appropriate distribution of reservoir properties and incorporation of bounding surfaces into the modeling workflow.

Grainflow deposits, which are internally massive and have fewer internal heterogeneities compared to wind ripple laminae, have the highest permeability of all facies. Depositional processes that destroy original bedding such as bioturbation or SSD create relatively high permeability pathways. Facies with closely spaced mm-scale bedding such as ripple laminated or wind ripple laminae on average had the lowest permeabilities.

Bounding surfaces in the White Rim Sandstone and other eolian units occur at a variety of scales from the mm to 10s of m scale (vertical scale) (figures 4-2A and 4-9). The deflation surfaces (i.e., 1st order bounding surfaces) can be incorporated as stratigraphic breaks or potential baffles in the model and can aid in determining the vertical cell size. The deflation surfaces act as flow barriers which can be incorporated as low vertical cell transmissibility if these surfaces are used to determine cell height. Internally, cross-bed set and internal laminae surfaces (2nd and 3rd order surfaces, respectively) create vertical anisotropy (Kh>Kv). This can be incorporated into the models via cell anisotropy. These findings are applicable to other eolian modeling projects or reservoirs (e.g., Navajo Sandstone); however, the White Rim Sandstone in the subsurface region of the prospective injection site has non-reservoir porosity and permeability due to calcite cementation, which makes the entire interval an unsuitable injection site.

These findings have broader implications for eolian reservoir modeling and petrophysics. The appropriate partitioning of eolian reservoirs into flow units for modeling purposes poses a challenge. Texturally, eolian dune lithofacies have similar grain sizes and composition. Furthermore, eolian dune facies commonly do not have statistically different porosity populations that can be resolved on log data. However, minute changes in the ordering of the individual grains (e.g., mm-scale inversely graded beds in wind ripple laminae versus “disordered” packing in massive beds) can result in vastly different permeability values. Therefore, traditional porosity logs may not be adequate to appropriately characterize flow units within an eolian reservoir because higher permeability and lower permeability eolian lithofacies do not have resolvable porosity differences.

In contrast, the vertical spacing of bounding surfaces and other sedimentary structures (or lack thereof) can be used to more accurately populate permeability values in reservoir models. State-of-the-art borehole imaging techniques could prove useful in determining facies and the presence of bounding surfaces through the reservoir and lead to a more accurate reservoir model. Additionally, grainflow and wind ripple facies, which are commonly lumped as “dune facies,” should be broken out into their individual components or at least their relative proportions (e.g., wind ripple facies are more common at dune toes). Although these two facies represent the same environment, eolian dunes, they have vastly different rock properties and need to be modeled separately.

SUMMARY

The White Rim Sandstone in the San Rafael Swell has two main stratigraphic reservoir units characterized by different sedimentary textures and structures: (1) the lower dm- to m-scale, cross-bedded eolian dune sets (i.e., alternating sets of grain flow and wind ripple laminae), and (2) the upper 4 to 10 m of the formation that represents a marine transgression and reworking of the sediment. The transgression that reworked and deposited the upper unit resulted in a distinct change in facies and the presence of abundant marine trace fossils. For outcrop samples, lithologic facies is the dominant control on permeability. Facies that had either minimal original bedding or disturbed original bedding such as grain flow, SSD, and bioturbation facies had higher permeability values (typically 100s of mD) than the finer-grained, thinly bedded wind ripple and ripple laminated facies (typically 10s of mD).

Outcrop samples of White Rim Sandstone show initial quartz cementation (i.e., quartz overgrowth cements) followed by rim forming calcite and iron oxide cementation. These samples have porosities of 10% to 20% and permeabilities of 10s to 100s of mD. Core samples had a different diagenetic history with increased compaction, initial quartz cementation, and subsequent patchy, pore-filling calcite cementation that destroyed much of the primary porosity and reduced the permeability by three to four orders of magnitude from 10s to 100s of mD to <0.1 mD.

Overall, given the poor reservoir quality of the core samples directly below the prospective injection site, the White Rim Sandstone likely would not make a good CCS reservoir target despite initial promising outcrop results.

CHAPTER 4 FIGURE AND TABLE CAPTIONS

Figure 4-1. Digital elevation model of the San Rafael Swell and regional stratigraphic section. The field sites for this study (A – Sids Draw, B – Sids Reservoir, C – Black Box trailhead) are marked in blue, the study sites from the Harston and others (2013) study are marked in purple, the Hamon USA No. 8-1 core location is denoted by the green circle, and the Hunter Power Plant is denoted by the white circle. The Huntington Power Plant is an ~58 km to the north-northwest of the study sites and the Tully No. 16-9-36D core is ~50 km to the north-northwest of the study sites. Insert: stratigraphic column for the field sites; star indicates the Permian White Rim Sandstone targeted for CO_2 injection.

Figure 4-2. Eolian dune facies consist of tens of cm to m-scale cross-bedded grain flow and wind ripple laminae that intertongue with subaqueous ripple laminated interdune deposits (A) (blue dotted lines indicate cross-bed set bounding surfaces). These facies are capped by 4 to 10 m of marine reworked sandstone with soft-sediment deformation (deformed bedding and injectites) (B), symmetric ripples (E and H), and extensive bioturbation (C, D, F, and G). The trace fossil assemblage, including *Ophiomorpha* (D and F) and *Thalassinoides* (G), indicates a marine shoreface environment.

Figure 4-3. Measured sections at all three field sites indicate a marine transgression of the Permian Kaibab sea and sediment reworking on top of a series of eolian facies.

Figure 4-4. Bounding surfaces typically occur at three nested scales. Deflation surfaces are relatively flat, laterally extensive horizons that commonly occur tens of m apart stratigraphically. Bedset surfaces denote individual cross-bed sets and can occur at tens of cm to m intervals. Internal bed/laminae surfaces separate individual grain flows or wind ripple laminae. These surfaces can occur at the mm to cm scale.

Figure 4-5. A and B – Clastic pipe eruption horizons are marked by outward flaring surfaces (blue solid and dashed lines) (Wheatley and Chan, 2016). C and D – Pipe eruption horizons occur at the transition between the lower and upper units at field site B and are likely related to the marine transgression of the Permian Kaibab sea.

Figure 4-6. Outcrop examples (A–D) indicate high quality reservoir potential sandstones; blue areas represent porosity. Petrographic studies show quartz overgrowth cements and, in some samples, minor carbonate and iron oxide cements. However, subsurface core examples (E–H) of the same formation ~34 to 48 km to the west indicate sandstones with very limited to no reservoir potential. Compaction and carbonate cementation have destroyed nearly all of the primary porosity. Images in E and G have been stained with alizarin red to identify calcite cement. A, B = wind ripple; C, D = eolian dune (undifferentiated) (D is a crossed nicols image of C); E, F = Hamon USA No. 8-1 core (F is a crossed nicols image of E), depth 1568.5 m; G, H = Hamon USA No. 8-1 core, depth 1569.1 m.

Figure 4-7. VNIR indicates that outcrop samples (n = 58) have multiple diagenetic phases including: (1) calcite, (2) hematite, (3) goethite, and (4) a clay mineral. In contrast, core samples (n = 76) do not have any iron oxide phases and only have absorption peaks for (1) calcite, and (2) a clay mineral.

Figure 4-8. Depositional textural and the presence and spacing of bounding surfaces plays a key role in determining permeability. Facies with fewer internal laminae or bounding surfaces tend to have higher permeability values than facies with preserved mm-scale bedding. Destruction of primary bedding through soft-sediment deformation or bioturbation can increase permeability by creating preferential flow pathways.

Figure 4-9. Although dune facies (i.e., cross-bedded grain flow and wind ripple facies) are compositionally and texturally similar, internal laminae bounding surfaces greatly affect the comparative permeability between each facies. The wind ripple facies has mm-scale, inversely graded laminae, which creates minor flow baffles compared to the internally massive grainflow facies, which results in lower permeability values. Yellow triangles indicate grading.

Table 4-1. White Rim Sandstone facies and facies associations.

Rocky Mountain CarbonSAFE Phase I

Appendix E

SEDIMENTOLOGY, STRATIGRAPHIC ARCHITECTURE, AND RESERVOIR CHARACTERIZATION OF THE LOWER JURASSIC NAVAJO SANDSTONE—PROSPECTIVE STORAGE EFFICACY FOR CARBON CAPTURE AND SEQUESTRATION

SEDIMENTOLOGY, STRATIGRAPHIC ARCHITECTURE, AND RESERVOIR CHARACTERIZATION OF THE LOWER JURASSIC NAVAJO SANDSTONE—PROSPECTIVE STORAGE EFFICACY FOR CARBON CAPTURE AND SEQUESTRATION

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INTRODUCTION

The goal of this study is to describe the Lower Jurassic Navajo Sandstone in terms of its potential as a lithological reservoir for storage of supercritical carbon via subsurface injection. The Navajo Sandstone was selected as the reservoir target for injection and storage sites of the Hunter and Huntington Power Plants. Outcrop exposures were chosen based on accessibility, proximity to the proposed injection locations, completeness of section, and relative distribution across the San Rafael Swell. Navajo cores were examined from Covenant oil field in the central Utah thrust belt about 55 miles to the west of the San Rafael Swell as a producing reservoir analog to the outcrops and the study sites. Porosity and permeability are among the two most important lithologic properties of a potential storage reservoir (Olierook and others, 2014). Multiphase flow measurements were conducted on core from Covenant oil field as well as outcrop samples. These properties are key in describing: (1) the volume of carbon that could potentially be stored, (2) limits on injection rate, and (3) probable fluid pathways. Therefore, the distribution of stratigraphic, lithologic, and diagenetic features, and their effect on porosity and permeability both spatially and stratigraphically, is key in understanding the utility of the Navajo Sandstone as a potential reservoir.

JURASSIC NAVAJO SANDSTONE: OUTCROP ANALYSIS

Past studies of the Navajo Sandstone in the San Rafael Swell have focused on it as a classic example of eolian facies (Sanderson, 1974) and as an excellent outcrop analog for hydrocarbon reservoirs and CCS models (Dalrymple and Morris, 2007; Hansen, 2007; Allen and others, 2013). Our study aimed to examined both outcrop and core scales of investigation with a focus on the stratigraphic evolution of the Navajo in order to understand large-scale regional trends which would affect both the storage and migration of carbon-fluids in a subsurface injection scenario.

Study Area

Observations focused on outcrops along Buckhorn Draw Road, which is the study site nearest to the Hunter Power Plant. In order to interpret regional-scale stratigraphic trends, this study identified two additional study sites: Justensen Flats, which is located on the western flank of the San Rafael Swell and is south of Buckhorn Draw Road, and Temple Mountain Campground, which is located along the southeastern flank of the San Rafael Swell north of Goblin Valley State Park.

Buckhorn Wash

The Buckhorn Wash region is located along the northwestern flank of the San Rafael Swell south of Price, Utah, and east of the Hunter Power Plant along Buckhorn Draw Road. Buckhorn Wash follows an incised valley through the majority of Jurassic, Triassic, and some Permian age units, which comprise much of the San Rafael Swell (figure 5-2).

Justensen Flats

Justensen Flats is located south of Interstate 70 (figure 5-2) and represents the westernmost outcrop location studied. Justensen Flats is interpreted as the top of an interval of interdune deposits, which forms an erosionally resistant bench relative to the cross-bedded sandstones above and below. The bench sits stratigraphically in the middle of the formation. This unique location allows for easy examination of Navajo section via a dirt road that gently traverses from the upper contact with the Middle Jurassic Carmel Formation, down to the lower contact with the Lower Jurassic Kayenta Formation.

Temple Mountain Campground

The Temple Mountain Campground site is the easternmost study location (figure 5-2) and the Navajo section was measured in most cases directly adjacent to, or very near the camp road which cuts directly down-section. Given the roughly north-south strike and eastern dip of units in this part of the San Rafael Swell, walking east along this road enables the observer to traverse upwards stratigraphically. A petroglyph view area north of the camp road roughly defines the contact between the Jurassic Kayenta Formation and the Navajo Sandstone, and farther east a rocky wash to the south of this road exposes the upper contact with the Jurassic Carmel Formation.

Lithofacies Categories

Together, the four complete measured sections recorded in this study describe the three locations. These sections show that across tens of kilometers, distinct stratigraphic intervals are persistent. Deposition appears relatively uniform across this region (figures 5-3 and 5-4). All study sites expressed 14 distinct lithofacies (table 5-1). These lithofacies were classified based on grain-size, texture, primary sedimentary structures, thickness, lateral extent, and bed contact relationships.

Three lithofacies contain undeformed, high-angle (<35º) cross-bed sets of varying geometries. These three quartz-arenite lithofacies are classified as planar cross-bedded sandstone (Pxb), large trough cross-bedded sandstone (Txl), and small trough cross-bedded sandstone (Txs). The Pxb beds are generally ~1 to 5 m thick, with flat erosional tops and flat erosional bases, and thin laterally over 10 to 100 m. The Txl beds are ~5 to 30 m thick, with erosional tops and gentle concave-up or sinusoidal basal contacts extending for 10 to 100 m. The Txs beds are 0.1 to 1 m thick over lateral distances of 1 to 10 m, and have erosional concave-up top and basal contacts.

Four non-cross-bedded lithofacies are characterized by some or all of five diagnostic features: (1) thinly bedded, (2) lenticular beds, (3) distinct horizontal sedimentary structures or completely structureless (massive), (4) high concentration of carbonate-cement relative to other facies, and (5) laterally extensive, ~10 to 100 m. Sheet plane-bedded quartz arenite sandstone (Spb) facies remain thin (<0.1 m) over 10 to 100 m, have flat erosional top contacts, and flat bottom contacts that are either conformable or erosional. Ripple laminated sandstone (Rip) facies are composed of hematite and carbonate-cemented quartz arenite. This Rip facies is 0.1 to 0.5 m thick over lateral distances of 10 to 100 m, with flat erosional top contacts, concave-up conformable basal contacts, and internal mm-cm asymmetric or symmetric ripple laminae. Undulose laminated sandstone (Unl) facies remain thin (<0.1 m) over 10 to 50 m, have flat erosional top contacts, and concave-up conformable basal contacts. The Unl facies exhibit undulose/crinkly lamina composed of carbonate cement-rich quartz arenite. Massive sandstone (Mss) facies have a lack of sedimentary structures, thick 1 to 5 m over 10 to 100 m, have flat, conformable top and basal contacts, and commonly underlie either Rip or Unl beds. The Rip and Unl facies both have high concentrations of carbonate cement, whereas both the Mss and Spb facies lack carbonate cement. The Spb facies can resemble the toe of a dune but are easily distinguished where a three-dimensional (3-D) outcrop exposes a laterally extensive, very thin sandstone bed.

Two lithofacies are classified by the presence of either brittle or ductile deformation. Soft-sediment deformed sandstone (Ssd) facies are 1 to 10 m thick over 10 to 100 m. The Ssd facies contain plastically folded, contorted, and overturned cross-bedding, of which strata are laterally conformable and connected to undeformed cross-bedding. Brittlely deformed sandstone (Bss) facies are 1 to 7 m thick over 10 to 100 m, and contain brittle, or non-plastic, stratal deformation of other semi-lithified cross-bedded strata such as Pxb, Txs, and Txl facies.

Four lithofacies are classified based on the geometries of their deposition and close stratigraphic relationships to one another. Interbedded sheet sandstone and conglomerate (Isc) facies contain alternating strata of sandstone and matrix-supported pebble conglomerates. The Isc strata are 0.5 to 5 m thick, extending 100 m, and are conformable with overlying high-angle cross-beds. Intraformational conglomerate (Itc) facies are matrix-supported conglomerates with green pebble-sized clasts suspended in carbonate-rich mud/sand matrix. The Itc strata remain thin (0.1 to 1 m) extending 100 m, and appear conformable along basal and top contacts. Sheet mudstone (Smd) facies are thin (0.1 to 1 m) green mudstones extending 10 to 100 m. The Smd strata have sharp erosional bases and are conformable with overlying beds. Internally, Smd clasts appear in Isc conglomerate horizons as apparent rip-up clasts. Cross-bedded to cross-laminated sandstone (Xxs) facies are 1 to 5 m thick over 10 to 100 m, with very deep erosional bases that incise cross-bedded strata. The Xxs facies have very small, mm-cm thick low-angle cross-beds and/or cross-laminations that occur in erosional contact with larger, higher-angle cross-bed sets. These Xxs strata appear below or very near to Smd, Itc, and Isc facies.

Pseudo-bedded sandstone (Psb) lithofacies are characterized by noticeably white, bleached beds that are mostly structureless, but contain some primary bedding. These intervals are very thick 3 to 30 m, extending >500 m.

Lithofacies Associations

Five lithofacies associations group and link related facies from table 5-1 and the lithofacies descriptions above. Here they are classified into lithofacies associations based on the major depositional environment interpreted for each group of lithofacies.

The Pxb, Txl and Txs facies express high angle, tabular, regular cross-bedding, and thus they were grouped together into an eolian dune lithofacies association (figure 5-5).

The Spb, Rip, Unl, and Mss facies are grouped based the common lack of cross-bedding, consistent stratigraphic successions in which they are observed to occur together, and presence of carbonate cement in the case of Rip and Unl. These four interpreted non-dune lithofacies are correspond to sedimentary features associated with interdune deposition (ID; figure 5-6).

The Mss and Bss facies are grouped into a deformed association because they represent intervals of rock which have primary structures preserved, but have been apparently deformed since original deposition (figure 5-7). The deformed facies association contains both syndepositional soft-sediment (plastic) deformation (Ssd) facies and brittle (non-plastic) deformation (Bss) facies (figure 5-8), the latter of which may preserve either syndepositional deformation and/or post-lithification structural deformation. Post-lithification structural deformation is distinguished from syndepositional deformation by the observation of characteristics and features including but not limited to large fault surfaces extending >100 m, deformation bands, and slickensides. In many cases Ssd and Bss strata occur either adjacent to one another or within the same interval, in which case there is likely a genetic syndepositional cause.

A mixed eolian-fluvial association is applied to the Isc, Itc, Smd, and Xxs lithofacies due to their common occurrence together, the genetic relationship between Smd strata and Isc clasts, and the energy regime required to deposit pebble-sized clasts in the Isc and Itc facies (figure 5-7). The Psb facies is classified as a distinct association which is consistent with a post-lithification fluid-alteration process that preserves a form of pseudo-bedding association (figure 5-9). The Psb facies either lack primary bedding structures entirely or have very faint cross-bedding visible. The Psb beds are very white, appearing bleached, which may be due the migration of a reducing-chemistry fluid that passed through the rock. A reducing fluid may dissolve iron from the host rock into solution and transport it. This lithofacies is interpreted as a pseudo bedded association without implying a genetic cause for these features. The Psb lithofacies warrant additional study.

Reservoir-Pertinent Depositional Fabrics

Although there are a number of distinct lithofacies (table 5-1) present throughout Navajo section, a smaller set of three reservoir-pertinent depositional fabrics are likely the most important factors to affect fluid flow and compose ~95% of vertical section. The two reservoir-supporting fabrics are: internal cross-bedded intervals of wind ripples (WR) and grainflow (GF) tongues (figure 5-10A through 5-10E), and both fabrics are present in the Pxb, Txs, and Txl lithofacies. A third important reservoir-baffle/barrier fabric is interdune deposition (ID) (figure 5-10E and 5-10F), and comprised of the Spb, Rip, Unl, and Mss lithofacies. The Rip and Unl lithofacies comprise ~80% of all the ID fabrics.

Reservoir-Support Fabrics: Wind Ripple and Grainflow Cross-Bedding

The WR fabrics are thin (mm) translatent laminae that record the migration of a rippled dune-slope and occur because of the preferential sorting of eolian grains along either a ripple trough or crest. The WR cross-beds preserve inverse grading and show typical pin-stripe lamination within cross-beds (Hunter, 1977). The GF fabrics are tongues that occur at various scales, usually proportional to their cross-bed foreset thickness. A single GF tongue records a sand avalanche along a dune slope and is internally structureless. A GF tongue is thickest at the top of its bed with high-angle bounding surfaces, and thins at the base of its bed becoming nearly tangential with the lower bounding surface of the foreset (Hunter, 1977). Together, WR and GF reservoir-pertinent fabrics comprise all interpreted dune-associated lithofacies in varying ratios and 85% to 90% of Navajo Sandstone vertical section. Additionally, the WR cross-beds tend to have lower porosity (~7%) and the GF cross-beds tend to have higher porosity (~22%), which was confirmed via petrographic thin section (figures 5-11 through 5-13).

Reservoir-Baffle/Barrier Fabric: Interdune Lenses

The ID baffle/barrier fabrics are defined as all interdune-associated lithofacies (the Spb, Rip, Unl, and Mss lithofacies). The Rip and Unl lithofacies comprise ~80% of all ID fabrics. Although the ID fabrics represent 5% to 10% of Navajo Sandstone vertical section they are crucial to reservoir characterization because they generally represent baffles and/or barriers to flow. The ID lenses are finer grained and have lower porosity and lower permeability than the WR or GF fabrics. All laboratory analyses focused on these three fabrics to make interpretations about reservoir quality.

Utility of Reservoir-Pertinent Fabrics

The Navajo Sandstone can be understood more efficiently by examining the stratigraphic occurrence and relationships of the WR, GF, and ID fabrics. Given that the WR, GF, and ID intervals have very different porosity (~7%, ~22%, and ~3%, respectively) and permeability (figures 5-12 and 5-13), and represent 95% of vertical section, they are the most useful fabrics for analysis to effectively characterize the Navajo Sandstone as a reservoir.

Porosity and Permeability

Porosity

Hand samples of the Navajo Sandstone were collected at Buckhorn Wash, Little Wedge, and Justensen Flats areas. For the three major reservoir-pertinent fabrics, porosities were measured via thin section pore-space estimates and analyzed with respect to reservoir fabric type and stratigraphic height above the base of the Navajo Sandstone (figure 5-12). Sampling for porosity was concentrated in the lower stratigraphic zone because this stratigraphic interval has the greatest lithologic variation within the unit and has not been previously characterized by other studies. Photomosaics of 19 thin sections at 25-50x power were used to estimate porosity by isolating the area of blue epoxy in the Image J™ software package using a color threshold tool. Porosity estimates are based on cross-sectional (2-D) data and may be limited by the single orientation from which they were derived (figure 5-11). The WR cross-beds have average porosity of ~7% whereas the GF cross-beds have average porosity of ~22%. Most notably, there appears to be a positive correlation between the cross-bedded reservoir fabrics (WR and GF) and stratigraphic height. The ID samples have much lower average porosity (~3%) than the WR and GF fabrics (7% and 22%).

Navajo samples, including the avalanche, wind ripple, and interdune facies were also sent to Schlumberger Laboratories and analyzed for porosity (and permeability) (table 5-2). All samples were analyzed at ambient pressure and several were also tested at 2700 psi and then 3500 psi to simulate the change with burial. Porosity in dune facies ranges from 15.6% to 21.1%, with GF (avalanche) averaging 14.5% and WR at a surprising 18.1%. Grain density averages 2.65 cm^3. The interdune samples averaged 8% porosity.

Permeability

Permeability has a similar distribution as porosity among reservoir-pertinent fabrics (figure 5-13). Reservoir-supporting cross-bedding fabrics (GF and WR) have outcrop permeabilities range from ~100 to 9000 mD. These values were acquired using a TinyPerm II permeameter which is extremely susceptible to changes in temperature (pressure), poor instrument-target seals, and high measurement variability, as observed during data collection in this study. Measurements were typically repeated four to six times and averaged out, however, values are likely unrealistically high. Thus, we recommended that these permeabilities should not be used for subsurface modelling because they reflect a low precision. Permeability measurements are based on outcrop, and though fresh surfaces were used to estimate permeability, values from fresh surfaces did not differ from weathered surfaces. The maximum values obtained for permeability sometimes exceeded 20,000 mD, suggesting a poor seal or overly weathered media for accurate measurement. Additionally, subaerial exposure and periodic precipitation may have enhanced or impeded pore fluid pathways, and are not representative of subsurface rock.

The lowest permeabilities measured correspond to the ID fabrics at 5 to 590 mD (figure 5-13) whereas higher average permeabilities were measured in both types of reservoir-supporting fabrics (~100 to 3000 mD). The ID fabrics regardless of stratigraphic range, have lower porosity and permeability than any cross-bedding fabric.

Laboratories analysis of hand samples from the dune facies show nitrogen permeabilities ranging just 2.96 to 2416 mD%, with GF (avalanche) averaging 268 mD and WR at a 1278 mD (table 5-2). The interdune samples had a maximum permeability of 18.5 mD.

Architectural Observations

The lithofacies present within the Navajo Sandstone are stratigraphically controlled by original depositional textures. The consistent stratigraphic division of the formation is evident in each section measured from the eastern flank of the San Rafael Swell across to the northwest. Some lithofacies are limited to either the upper or lower stratigraphic zones, but others span both. The lower Navajo stratigraphic zone defined by Marzolf (1983) is the stratigraphic interval from Navajo base up to the youngest observed occurrence of an ID bed (Spb, Rip, Unl, or Mss lithofacies). Therefore, the upper stratigraphic zone is defined as the interval from the top of the youngest ID bed to the Navajo top contact. The boundary between the lower and upper stratigraphic zones is not exact and it is possible that this study did not identify the absolute youngest ID beds present in measured sections given the limited lateral continuity of ID lenses.

Lower Navajo Sandstone Stratigraphic Zone

In the lower stratigraphic zone of the Navajo Sandstone (60 to 80 m thick), the most prominent architectural features are flat lying, conformably deposited lenses of carbonate-cemented sandstone; Rip and Unl lithofacies; ID baffle/barrier fabrics. The lenses are lenticular with erosionally truncated tops, marking major bounding surfaces. They are thin (0.1 to 5 m) and their lateral extent is proportional to their thickness at a ratio of ~1:200 (e.g., a 1 m-thick bed typically extends ~200 m across). These lenses are thickest towards the center and taper to the sides where they pinch out. The ID beds are not always symmetrical in thickness. The thickest ID fabric observed was ~5 m whereas the thinnest was ~5 cm. The greatest ID fabric lateral extent directly observed was ~500 m whereas the thinnest was ~10 m.

Cross-bedding in the lower stratigraphic zone of the Navajo Sandstone is limited to thin (< 5 m) foresets of the Pxb and Txs facies, and major erosional bounding surface spacing is ~5 to 10 m. These beds lack thick GF intervals and are dominated by WR cross-beds and thin (<20 cm) GF cross-beds. The maximum cross-bed foreset thickness observed is ~10 m.

Interpreted Ssd facies occur in some isolated beds in the lower stratigraphic zone. Small <1 m Ssd facies below or adjacent to eolian-fluvial and interdune associated lithofacies are common.

Upper Navajo Sandstone Stratigraphic Zone

The upper zone of the Navajo Sandstone (60 to 80 m thick) is notable for its lack of ID fabrics, its thick cross-bed foresets (5 to 20 m), and the presence of both thick Ssd and Bss lithofacies. The Txl cross-beds are the dominant lithofacies present. The Txl foreset thickness increases dramatically from the lower stratigraphic zone and reaches a maximum of 20 m. Individual GF tongues increase in size (up to 1 m) and increase in concentration relative to WR fabrics (up to 100%) within cross-bed foresets. The WR cross-beds are also present in the upper stratigraphic zone; however, GF fabrics are distinctly thicker and comprise a greater concentration of cross-bed foresets than in the lower stratigraphic zone.

The deformed Bss and Ssd facies are most prominently expressed in the upper zone, commonly in adjacent beds. The Bss facies are only observed in the upper zone, whereas the Ssd facies are observed in both zones. From Bss beds, structureless sandstone matrix commonly extends into Ssd beds. Transmissivity seems to occur between adjacent Bss and Ssd intervals. The thickness and the degree of Ssd deformation is much greater in the upper stratigraphic zone than in the lower. The Ssd facies have a locus of contortion that decreases laterally in outcrop where strata become conformable with adjacent undeformed cross-bedding structures. In the upper stratigraphic zone, the most prominent Ssd fabric is >10 m in thickness with large isoclinal folds. This deformation spans two cross-bed foresets and is erosionally truncated (figure 5-8A). Deformed intervals are commonly truncated by major erosional bounding surfaces and both the Bss and Ssd lithofacies are often bleached and/or stained.

Architectural Interpretation

The disparate occurrence of lithofacies across lower and upper stratigraphic zones likely reflects a long-term evolution of the erg (figure 5-14). The environmental conditions and internal organization of the sand-sea present in the early history of the Navajo Sandstone were likely wetter than those during the latter part of deposition. The deposition of the ID deposits in the lower stratigraphic zone only occurs in a wet-eolian framework in which the water table is sufficiently shallow and the ground has enough moisture to hold sediments in place. As interdune areas stabilize from sufficient subsurface moisture and/or vegetation, windblown sediments derived from dunes continue to be transported. This transport occurs at the volumetric cost of dunes which are the source of these sediments, and results in decreased dune heights (Kocurek and Havholm, 1993). Thus, smaller dune foresets are typically associated with wet eolian environments. The zone in which dunes can potentially accumulate is proportional to the height of dunes crests and also relies on sediments being dry so that winds are able to entrain sediment. Vegetation and surface moisture in an erg act as a baffle and/or barrier to eolian transport (Kocurek and Havholm, 1993). As sediment erodes from dunes, transport-inhibiting interdune areas continue to grow the cost of dunes. The continuous entrainment of sediment, and thus the construction of taller dunes, is not possible when moist surface conditions and/or vegetation are present. Large dune forms are associated with drier conditions and smaller dune forms are associated with wetter conditions (Kocurek and Havholm, 1993).

The absence of all interdune-associated lithofacies in the upper stratigraphic zone and presence of large Ssd and Bss intervals may reflect the presence of a deeper groundwater table, and larger dunes in the latter history of the Navajo Sandstone. This hypothesis is also supported by the presence of thicker Txl lithofacies in only the upper stratigraphic zone. The larger thickness of the Txl cross-beds relative to the Pxb and Txs cross-beds of the lower stratigraphic zone physically require either a larger original dune form or less post-depositional erosion in order to be preserved. Given the consistent occurrence of thick Txl beds across all study locations, it likely reflects a larger original dune form, and thus an evolution in the Navajo paleoenvironment and/or sediment-supply.

Diagenesis

Observations

Limited mineralogical diagenetic interpretations were made from both thin section data of reservoir-pertinent fabrics and outcrop observations of lithofacies. Three main diagenetic cements found in the 34 thin section samples analyzed include quartz overgrowths, iron-oxide coatings, and pore-filling carbonate cements.

Carbonate cements are only observed in the ID fabrics as pore-filling cements. No other cements are observed in ID fabrics. All other reservoir-pertinent fabrics and lithofacies contained some amount of quartz overgrowths, which are most common in “bleached” and white rocks, and iron-oxide coatings, which are common in yellow, orange, red, and dark brown rocks.

Interpretations

The development of specific minerals, mineral fabrics, and filling of pore-space between framework grains are divided into three stages of diagenesis. These three stages describe the relative depth of the rocks during each stage and the specific mineralogical and textural changes that occur during each stage (Walker and others, 1978; Burley and others, 1985).

Eogenesis is the earliest stage of diagenesis and occurs during shallow burial. The Ssd facies and adjacent intervals of syndepositional Bss facies were likely formed during this stage when sediments were not yet totally lithified. This is also most likely the stage in which carbonate minerals developed as cements in the pore space of the ID fabrics and caused a large decrease in any original porosity in these beds. Many of the iron-oxide coatings around grain boundaries were also likely formed during this stage. Iron oxide-rich strata within the Ssd fabrics are deformed, suggesting that deformation occurred post iron oxide development. It is unlikely that there was preferential development of iron oxide coatings in isolated segments of strata in the Ssd intervals post deformation. Compaction, decreased pore-space volume, and development of some accessory clay minerals likely occurred during this stage as well.

Mesogenesis is the middle stage of diagenesis associated with deep burial of rock. This stage is likely reflected in quartz overgrowths, more grain point contacts with compaction, and an overall decrease in porosity and permeability.

Telogenesis is the final stage of diagenesis during which rock is exhumed after deep burial. Structural deformations, associated with Laramide orogenesis, including faulting, development of joints, and deformation bands likely occurred during telogenesis. This stage may include the presence of migrating fluids, which caused the preferential bleaching and/or precipitation of iron minerals. The geomorphic patterns of bleaching and iron precipitation appear to be controlled by primary sedimentary features, most notably erosional bounding surfaces, the ID lenses, the WR and GF cross-beds, as well as many of the structural deformations such as fault surfaces.

Previous studies suggested that various buoyant fluids migrated in the Navajo reservoir (Potter-Mcintyre and others, 2013), which would behave similarly to a super-critical carbon fluid. In this previous study, large intervals of sandstone are bleached and lack iron-oxide cements, whereas other intervals appear to preserve oxidizing fronts where iron-bearing minerals occur along various boundaries. Faults, erosional bounding surfaces, and syndepositional deformation intervals commonly show iron cements. This suggests that these surfaces and intervals interacted with migrating fluids for sufficiently long periods of time to precipitate iron minerals, and perhaps acted as stratigraphic baffles and/or barriers which impeded flow. The movement of these fluids is complex and warrants additional investigation to better understand the past history of fluid alteration within the Navajo Sandstone.

Structural Deformation

Structural deformation, or brittle displacement of original rock by mechanical failure due to stress after lithification, exists in a spectrum ranging from major displacement along normal faults (10 to 20 m) to cm-scale en-echelon microfaults (figure 5-8C). The majority of faults observed within the Navajo Sandstone are contained within the upper zone, perhaps due to the lack of ID lenses and/or higher porosity. Some of the larger displacement (20 m normal offset) faults likely penetrate the lower stratigraphic zone, but smaller faults and microfaulting associated with main fault strands seem to be limited to the upper stratigraphic zone. Slickensides, or fabrics of extremely fine-grained material produced from the cataclasis of larger, pre-existing grains during faulting, are present along many fault surfaces and weather in positive relief. Slickenside thicknesses ranged from 1 to 4 mm and were composed of both quartz and/or iron oxides. There was no significant difference in permeability between beds that contained faults and beds that did not in the same stratigraphic zone. However, several measurements of permeability normal to fault slickensides (on the fault surface) yielded results between ~1 to 500 mD.

In the upper stratigraphic zone of the Navajo Sandstone there are many examples of deformation bands, which are linear (sometimes conjugate) or sinusoidal fabrics of fine grained or recrystallized material formed from the brittle cataclasis of preexisting grains resulting in reduced porosity and permeability (Fossen and Hesthammer, 1997; Davis, 1999; Zuluaga and others, 2014). Deformation bands in the Navajo are most common in high-strain zones near fault strands, in relatively high porosity (>15%), thick cross-bedded sandstones (Fossen and Hesthammer, 1997; Zuluaga and others, 2014). Past measurement of eolian facies associated with deformation bands suggest that more porous rock (>15% porosity and >1000mD), specifically the GF fabrics, are more likely to develop deformation bands than less porous beds, including the WR fabric-dominated beds (Fossen and Hesthammer, 1997; Schultz and others, 2010; Zuluaga and others, 2014). This study did not find a difference in the permeability between beds that contained deformation bands and beds that did not, which may be a result of Tiny Perm II precision. These features have small lengths (on average <4 m) and thin widths (<2 mm). It is unlikely these features represent a major baffle or barrier to flow. However, the exclusive occurrence of deformation bands in areas <100 m from major faults, may be useful to integrate in high-resolution modeling of fluid migration in highly faulted regions.

DISCUSSION

Depositional Environments

The lower stratigraphic zone of the Navajo Sandstone likely represents deposition in high water table conditions. Given that the fluvial Kayenta Formation commonly intertongues with the basal Navajo Sandstone, the lower stratigraphic zone represents a progressively drying environment that periodically flooded between dunes when there were sufficiently high water table conditions present. These periods may have included fluvial deposition (both channel and floodplain), lacustrine deposition, possible sabkha deposition, and uncommon drier (Spb lithofacies) interdune deposition.

The upper stratigraphic zone of the Navajo Sandstone likely represents a much drier, lower water table environment, which precluded the formation of interdune flats (Kocurek and Havholm, 1993) and was dominated by large draas and dunes. Seismic activity and dune slope-failure may have caused deeper groundwater to move to the surface causing violent deformation in the subsurface. Additionally, the Navajo did not likely have desert oases in the latter part of its depositional history. Navajo deposition likely evolved from a periodically wet eolian environment with common interdune flats to a very dry erg-dominated environment devoid of interdune flats.

Fluid Pathways

Records of past fluid migrations provide important clues as to the preferential fluid pathways that exist within eolian units. Major erosional bounding surfaces act as first-order controls on fluid movement (Potter-Mcintyre and others, 2013). Additionally, faults, joints, and other fractures likely act as diagenetic fluid conduits. A summary of potential baffles and barriers to flow as well as fluid migration in unrestricted flow environments is outlined in figure 5-15.

The Navajo Sandstone vertical section can be efficiently assessed for reservoir potential through the examination of key reservoir-pertinent fabrics that include wind ripple (WR) cross-bedding, grainflow (GF) cross-bedding, and interdune (ID) lenses. The WR cross-beds and GF cross-beds comprise 85% to 90% of Navajo section, range in porosity between ~7% to 22%, and have permeabilities between 100 to 1500 mD(?). The ID fabrics, which comprise only 5% to 10% of total vertical section but are limited to the lower stratigraphic zone, have average porosity of ~3%, and permeabilities between 5 and 590 mD.

The architectural arrangement of reservoir-pertinent fabrics is the largest-scale control on fluid flow in the Navajo Sandstone. In particular, the high concentration of the GF cross-beds relative to WR cross-beds, and thickness of rock between major erosional bounding surfaces are perhaps the most important characteristics of reservoir-supporting rock fabrics in the Navajo. These reservoir-supporting rock fabrics are dominant in the upper stratigraphic zone. The presence of baffles and barriers to flow such as thin WR-dominant cross-beds, and the ID fabrics act to impede fluid migration and are dominant in the lower stratigraphic zone. Furthermore, the lensoidal, thin morphology of ID fabrics may act to preferentially deflect fluid laterally, and may actually slow injected fluids from migrating vertically as quickly as they would in the GF and WR fabrics.

COVENANT OIL FIELD: CORE ANALYSIS

Field Overview

The only available and relevant subsurface Navajo Sandstone core applicable to our study was from the Wolverine Gas & Oil Federal No. 17-3 well (SENW section 17, T. 23 S., R. 1 W., SLBL&M, Sevier County) in Covenant oil field in the central Utah thrust belt (figure 5-1). Covenant field was discovered in 2004 and has produced over 25 million bbls of oil from the Navajo Sandstone and Temple Cap Formation (Middle Jurassic) (Utah Division of Oil, Gas and Mining, 2018). The field trap is an elongate, symmetric, northeast-trending fault-propagation/fault-bend anticline (figure 5-16), with nearly 800 feet of structural closure and a 450-foot-thick oil column (Chidsey and others, 2007). The Navajo and Temple Cap reservoirs are effectively sealed by mudstone and evaporite in the overlying Middle Jurassic Arapien Formation.

Lithology

The productive part of the Navajo Sandstone at Covenant field is about 240 feet thick and is characterized by thick, large-scale, trough, planar, or wedge-planar cross-beds (35 to 40º) commonly recognized as classical eolian dune features (figure 5-17); contorted bedding, wind ripples, and small-scale cross-beds are also common. Massive, homogenous beds with no distinct sedimentary structures or laminations are also recognized in the Navajo cores and were probably formed by water-saturated sand.

In general, core from the Navajo Sandstone consists of very well to well-sorted, very fine to medium-grained (1/16 mm to ½ mm), subangular to subrounded, light-yellow-gray sand or silt grains cemented by carbonate cement. However, some intervals show a bimodal grain-size distribution representing silty laminae between sand beds (figure 5-18A). The typical sandstone is 97% white or clear quartz grains (usually frosted) with some quartz overgrowths, illite, and varying amounts of K-feldspar (figure 5-18B). Feldspar is more common in the Navajo Sandstone than White Throne Formation (Chidsey and others, 2007).

Reservoir Properties

The Navajo Sandstone cores from Covenant field show heterogeneous reservoir properties because of (1) various cyclic dune lithofacies with better porosity and permeability in certain dune morphologies, (2) diagenetic effects, (3) extensive fracturing. Identification and correlation of the numerous bounding surfaces as well as recognition of fracture set orientations and types in individual Navajo reservoirs are critical to understanding their effects on production rates and fluid movement pathways. The average porosity for the Navajo Sandstone at Covenant field is 12% (Chidsey and others, 2007); the average grain density is 2.651 g/cm^3 based on core-plug analysis. Permeabilities in the Navajo from the core data are upwards of 100 mD. Porosity and permeability are greatest in thickly laminated avalanche deposits and along bounding surfaces (bedding planes), with preferred directions along the dip and strike of the individual slipfaces or lee faces (cross-beds).

Fractures and Diagenesis

Fractures in the Navajo Sandstone cores consist of two types: (1) early, bitumen and gouge-filled, silica-cemented, impermeable fractures (figure 5-17), and (2) later, typically open (little gouge or cement), permeable fractures. The later fractures are related to fault-propagation folding during the Sevier orogeny after deep burial.

Diagenetic effects and fracturing both reduce and enhance the reservoir permeability of the Navajo Sandstone at Covenant field. Quartz grains have minor overgrowths and some authigenic clay mineralization has occurred in the form of grain-coating, pore-bridging, and fibrous illite. Some ferroan(?) dolomite and fractured, corroded K-feldspar are also present. Development of bitumen and gouge-filled, silica-cemented fractures locally reduce reservoir permeability. Dissolution of silicate minerals and the development of open fractures increase reservoir permeability.

MULTIPHASE FLOW PROPERTIES OF THE NAVAJO SANDSTONE

To enable estimates of storage capacity, injectivity, and sealing behavior of the confining zone, we conducted measurements of multiphase fluid properties of available samples from core and outcrops. Herein we present methods and results for the following: mercury porosimetry on Navajo Sandstone samples; absolute and relative permeability on Navajo Sandstone samples, including stress-sensitivity; and petrographic observations of Navajo Sandstone thin sections. We also provide information on pore size types and flow characteristics of the Navajo. Our goal was to document our methods and disseminate results to the CarbonSAFE modeling team.

Sample Selection

A goal of the Site Characterization group was to perform capillary pressure and relative permeability tests on Navajo Sandstone samples that are at least representative of the three major facies—the upper dune facies, the middle interdune facies, and the lower dune facies—that have been identified as relevant for the injection site. Three challenges were the following:

(1) core from near the proposed injection site area was not readily available,

(2) it is not clear if the outcrop samples were that are representative of the subsurface, and

(3) our budget was limited to three relative permeability tests using the brine-CO_2 fluid pair.

We again evaluated the Navajo Sandstone core from the Federal No. 17-3 well in Covenant field, which is ~55 miles from the proposed injection targets near the Hunter Power Plant (figure 5-19). The core contains the upper dune facies, but not the middle interdune nor lower dune facies. To assess the relevancy of the core, we compared well logs from the Federal No. 17-3 well to wells near the Hunter Plant (figure 5-20). The Navajo thickens to the southwest as in seen within Castle Valley. The correlations show that the core in the Federal No. 17-3 well is entirely in the upper Navajo Sandstone. The Castle Valley area has better porosity development than in Covenant field. A question is the following: are the permeabilities from Covenant relevant to the Castle Valley area? We cannot be certain since there is no permeability data from Castle Valley area to compare. However, there was no geologic reason to suspect that there would be a significant difference in the porosity/permeability ratios between the two areas.

The concern about outcrop samples was that while they reveal trends in permeability and porosity for different facies that are similar to trends in the subsurface, the absolute values may be different. Thus, based on the above discussion, we used plugs from the Federal No 17-3 core, but also obtained plugs from outcrop to facilitate subsurface core-outcrop comparison. Table 5-3 lists the locations of six plugs from the Federal No. 17-3 core, at approximately 1.5-inch diameter, which were taken previously for permeability and porosity measurements. We sampled additional plugs at the same depths from the core, at approximately 1-inch diameter by 1-inch long for mercury porosimetry capillary pressure measurements. Relative permeability measurements were performed on three of the previously sampled plugs from table 5-3, namely at depths of 6805.2 feet, 6820.6 feet, and 6830.4 feet. The six plugs of table 5-3 are related to the core descriptions shown on figure 5-21. Two outcrops samples were taken, one from an avalanche tongue facies near the Buckhorn Wash site, and one from an interdune facies from the Little Wedge area described in Chapter 3.

Geomechanical Results

Leeb Hardness and seismic velocities were measured on core from the Federal No. 17-3 well. A Proceq Piccolo Hammer and Pundit ultrasonics system measured point load hardness and P- and S-wave velocities on samples from the Navajo Sandstone and the overlying Sinawava Member of the Middle Jurassic Temple Cap Formation at regular intervals (see Chapter 6 for description of the Temple Cap). Results are shown in figure 5-22. In general, velocities track hardness values, and both show a transition at about 6760 feet (the Temple Cap–Navajo lithological boundary as shown in figure 5-21 with Navajo lithofacies being slightly weaker than Temple Cap (Sinawava). There is also the suggestion of a slight lowering of velocities and Leeb hardness (which correlates to macroscopic geomechanical properties like unconfined compressive strength, and thus fracture gradient) of Navajo samples with depth.

Mercury Porosimetry

The mercury porosimetry measurements involve injection or intrusion of the "non-wetting" mercury into a rock sample from low to high (i.e., 60,0000 psia) pressure. Extrusion was also performed, which is the release of pressure with measurement of extruded mercury volumes. Rock samples are placed under vacuum prior to the measurements. Data produced include incremental (and cumulative) volumes of mercury injected into (or extruded from) the penetrometer bulb containing the rock sample and the corresponding pressures. A total of eight sample plugs were used in the mercury porosimetry tests (table 5-4) with six from the Federal No. 17-3 core and two from outcrop samples. Poro-Technology performed the mercury porosimetry tests on a Micromeritics AutoPore IV 9500 V1.09™ instrument.

Results are summarized in figure 5-23 (capillary pressure curves for six the samples listed in table 5-3 plus the two outcrop samples) and figure 5-24 (interpreted pore size distributions). Sample 3 (5-117 in table 5-3 at the depth of 6805.2 feet; eolian dune facies) has the lowest intrusion capillary pressures, whereas sample 2 (4-96 in table 5-3 at the depth of 6784.6 feet; dune toe) has the highest intrusion pressures. As discussed below, sample 5-117 (depth of 6802.0 feet) is medium grained with larger observed pore apertures (figure 5-25) compared to the other samples investigated. Porosity and permeability derived from the mercury intrusion results are given in table 5-4, which do not correlate with values obtained from earlier analyses on these cores.

Petrography

Petrographic observation was made on previously prepared standard-size thin sections from the Federal No. 17-3 core. Thin sections closest to the sample plugs and in the same lithofacies (based on figure 5-21) were selected. Photomicrographs of selected samples used for the relative permeability results (discussed in the next section) are shown in figure 5-25.

Sample 129 (sample 5 in table 5-3) is fine sand, moderately well sorted, and shows very little cement overgrowths. It is composed mostly of quartz grains and minor heavy mineral grains. Almost all quartz grains show signs of mechanical compaction, including trans-granular fractures emanating from grain contacts. Sample 139 (sample 6 in table 5-3) is fine to very fine sand, moderate-to-poorly sorted, and contains slightly less trans-granular fractures compared to sample 129. However, a long fracture is seen to traverse the sample from upper right to lower left. Again, very little cement is observed. Sample 117 is medium grained, well sorted, and shows abundant tangential contacts. Similar to samples 129 and 139, there is very little observed cement and textures are consistent with mostly mechanical compaction with minor amounts of chemical compaction. Porosity of these samples ranges from 12% to 17%.

Absolute and Relative Permeability Measurement and Stress Sensitivity

Absolute and relative permeability measurements were performed on three core samples (129, 139, and 117; see table 5-3) to examine the range of stress sensitivity and relative permeability within the Navajo reservoir in the Federal No. 17-3 well. Horizontal plugs were measured, weighed, and jacketed in a multi-layer configuration required for compatibility with supercritical CO_2 and acidified brines. For single phase permeability measurements, samples were flooded under vacuum with an NaCl brine made from reagent grade NaCl and milli-Q deionized water. The NaCl content matched measured values from nearby wells. Permeability measurements were made at increasing values of effective pressure (equal to confining pressure minus pore pressure) with the final effective pressure matching estimated in situ values of the core at the Federal No. 17-3 well depths. For two-phase supercritical CO_2-brine relative permeability measurements, CO_2 and brine were prepared from ultrapure CO_2 and the above brine solution and pre-equilibrated in a Hastelloy Parr reactor. Steady-state relative permeability measurements were made by simultaneously injecting CO_2 and brine at predetermined flow rates using Hastelloy ISCO high pressure syringe pumps. Relative permeability measurements were made after seven residence times (equal to pore volumes divided by volumetric flow rates). These measurements were followed by four CO_2 injection rates at increasing flow rates from ~1 mL/min to ~20 mL/min). These were used to determine capillary pressure curves for comparison to the mercury results, as well as to determine CO_2 relative permeability at irreducible water saturations. A final step used 100% brine flooding to assess relative permeability hysteresis and values of residual CO_2 saturation (extent of CO_2 trapping). These steps were carried out successfully for two of the three cores (samples 177 and 129); sample 139 failed due to a jacket leak.

Results of effective pressure-dependent brine permeability and brine-CO_2 relative permeability are shown in figure 5-26 with brine relative permeabilities shown in blue symbols and CO_2 relative permeabilities shown in orange symbols. Preliminary fits to Brooks-Corey functions are shown by the solid lines of like color. Single phase permeability for all three samples shows a similar stress dependency with monotonically decreasing permeability with effective pressure (we show curve fits for the higher effective stress values using a simple exponential function), with values for the sample 117 being slightly higher than the other two samples. This is consistent with the mercury intrusion measurements (sample 117 having slightly larger pore throats than the samples 129 and 139).

Relative permeability curves for samples 117 and 129 are very similar, with slightly lower irreducible water saturations and higher CO_2 relative permeability at irreducible water saturations for the medium grained 117 compared to the fine grained 129. Sample 117 has higher lower residual CO_2 saturations (i.e., trapped CO_2), and slightly higher brine relative permeability at residual CO_2 saturation than sample 129, again consistent with its slightly larger pore sizes and better sorting. Sample 139 has very low relative permeabilities compared to the other two samples, and this we attribute to grain flow and loss of cohesion of the sand pack observed after introduction of acidified brine. It is not known why 139 responded so differently to CO_2 exposure relative to the other samples.

SUMMARY

Measured sections and outcrop samples across the San Rafael Swell, and cores from Covenant oil field help characterize the suitability of the Navajo Sandstone as a CCS reservoir. There are 14 distinct lithofacies which are grouped into five lithofacies associations that correspond to interpreted depositional environments. Additionally, the sedimentological differences and stratigraphic distributions of three key reservoir-pertinent fabrics have the greatest impact on reservoir quality. Dune-associated lithofacies have the highest porosity and permeability, whereas interdune-associated lithofacies have the lowest permeability and porosity. Reservoir-supporting fabrics, WR and GF cross-beds, in the lower stratigraphic zone appear to have lower porosity and permeability than those in the upper stratigraphic zone. Moreover, the ID reservoir-baffle/barrier fabrics only occur in the lower stratigraphic zone.

Excellent porosity (~7% to 25%) and permeability (on average ~1500 mD[?]) exist within the entire Navajo outcrop to support substantial subsurface injection of sequestered carbon fluids in the western portion of the San Rafael Swell. The division of the Navajo Sandstone into a lower stratigraphic "wet" zone and an upper "dry" zone is also a suitable division of the unit in terms of reservoir quality. The lower zone is more lithologically heterogeneous, with baffles, and the upper is a more homogenous, "ideal reservoir" zone. Major erosional bounding surfaces act as first order controls on fluid migration. Horizontal interdune lenses, which are exclusive to the lower zone, act as baffles or potential barriers to vertical flow, and would likely deflect migration fluids laterally. Structural deformation as well as soft-sediment deformation occur on a larger scale in the upper stratigraphic zone. The upper stratigraphic zone would likely allow a buoyant carbon fluid to migrate vertically more readily than the lower Navajo zone due to the lack of ID fabrics and higher concentration of GF fabrics. Despite the differences in hydraulic conductivity between the upper and lower stratigraphic zones, both would comprise a reasonable storage reservoir for CCS.

Cores from the Navajo Sandstone in Covenant field display a variety of eolian desert lithofacies (dune and interdune), fracturing, and minor faults which, in combination, create reservoir heterogeneity. They also provide the subsurface petrological and petrophysical analog data critical modeling the Navajo reservoir in the study sites.

We provide measurements on geomechanical properties, mercury intrusion capillary pressure, and single and relative permeabilities of selected samples of the Navajo Formation from the Federal No. 17-3 well west of the San Rafael Swell. In general, the different lithofacies of the Navajo Sandstone are expected to behave similarly geomechanically and hydrologically to CO_2 injection, with small variations attributable to observed heterogeneities in grain and pore size. One possible item of concern is the apparent sensitivity of one sample with exposure to acidified brine, which exhibited a marked loss of cohesion. It is not known why this sample (139) responded in this fashion but should be investigated further in subsequent studies.

CHAPTER 5 FIGURE AND TABLE CAPTIONS

Figure 5-1. Location of Covenant field, Navajo Sandstone outcrops, uplifts, and selected thrust systems in the central Utah thrust belt, often referred to as the "Hingeline." Numbers and sawteeth are on the hanging wall of the corresponding thrust system. Colored (yellow) area shows present and potential extent of the Jurassic Navajo Sandstone/Temple Cap Formation play area. Modified from Hintze, 1980; Sprinkel and Chidsey, 1993; and Peterson, 2001.

Figure 5-2. Locations of measured stratigraphic sections and geologic units with major unconformities labeled (modified from Doelling and others, 2017). The Hunter Power Plant, which is one of two prospective carbon-capture sites, is located less than 40 km away from the Buckhorn Wash (BW) study site.

Figure 5-3. View to the northeast from a cliff overlooking Buckhorn Wash.

Figure 5-4. Navajo Sandstone measured sections displayed as interpreted lithostratigraphic facies; color denotes facies association.

Figure 5-5. Cross-bedded dune-associations (table 5-1) include the Pxb, Txs, and Txl lithofacies. A – Planar cross-bedded sandstone (Pxb) facies contain grainflow (GF) fabrics outlined by blue dashed lines, and are bounded by erosional bounding surfaces outlined in red. A thin lens of sheet plane-bedded sandstone (Spb) facies sits above the Pxb bed and is bounded by erosional surfaces. The picture is from the lower stratigraphic zone. B – Small trough cross-bedded sandstone (Txs) facies are dashed in red, are observed in erosional contact with underlying strata, and are erosionally truncated as indicated by the green dashed line in the lower stratigraphic zone. C – Large trough cross-bedded sandstone (Txl) beds are in erosional contact with one another along red dashed surfaces and truncated by a major erosional bounding surface (green dashed line), whereas individual dune migration slope surfaces are outlined in blue dashed lines. This picture represents the upper stratigraphic zone.

Figure 5-6. Interdune associations include the Spb (figure 5-5) Rip, Unl, and Mss facies. A – Ripple-laminated sandstone (Rip) facies display asymmetric ripples indicating apparent paleoflow trajectory to the left. B – Undulose laminated sandstone (Unl) facies display irregular, mm-thick laminae. C – Massive sandstone (Mss) facies lack internal structure and only occur beneath the Rip and/or Unl facies.

Figure 5-7. Fluvial associations. A – Interbedded sheet sandstone and conglomerate (Isc) facies, which are partly comprised of sheet mudstone (Smd) clasts. B – Cross-bedded to cross-laminated sandstone (Xxs) facies are present. C – Isc facies overlie both an Mss interval and an intraformational conglomerate (Itc) interval which appears to be plastically deformed by Mss and Isc beds, which thicken to the right. D – Sheet mudstone (Smd) facies composed of green siltstone and gypsum are present.

Figure 5-8. Deformed associations include the Ssd and Bss lithofacies. A – Soft-sediment deformed (Ssd) facies exhibit plastically deformed strata which are laterally conformable with undeformed Txl strata below and erosionally truncated by Txl strata above. B – This example of Bss facies contains a structureless sandstone matrix with horizons of non-plastically deformed strata. C – The Bss facies also include faulting, such as en-echelon faulting shown in this photo.

Figure 5-9. Psuedo-bedded sandstone (Psb) facies resemble massive sandstone (Mss) facies due to diagenetic bleaching, but unlike the Mss facies, are not completely structureless.

Figure 5-10. A – Wind ripples (WR) fabrics in outcrop. B – This example of WR cross-bedding in thin section displays characteristic inverse grading. C – Grainflow (GF) tongues are pinching out at a dune toe. D – This example of GF cross-bedding in thin section exhibits a typical massive texture. E – This carbonate-cemented sandstone is interpreted as an interdune deposit

(ID) fabric. F – This example of an ID fabric in thin section exhibits carbonate-rich matrix and pore-filling carbonate which has reduced porosity.

Figure 5-11. Thin sections prepared perpendicular to bedding were mounted in blue epoxy to estimate porosity. A – Wind ripple (WR) cross-bedding has low porosity values and B grainflow (GF) cross-bedding has generally higher porosity values.

Figure 5-12. Porosities plotted as a function of stratigraphic height above base of Navajo Sandstone by key reservoir-pertinent fabrics. Note greater porosity values in the GF and WR fabrics. The ID sample porosities appear limited to ~12% porosity across stratigraphic intervals.

Figure 5-13. A – Rock porosities and B – permeabilities are plotted as a function of key reservoir-pertinent fabrics.

Figure 5-14. Overall stratigraphic trends as a function of height above the base of the Navajo Sandstone. A – Syndepositional deformation in the Navajo includes both non-plastic and plastic deformation and is analyzed separately from structural deformation. B – Interpreted interdune deposits are absent from the upper stratigraphic zone of the Navajo. C – The relative dominance of internal cross-bedded fabrics changes from wind ripple (WR) dominated-fabrics in the lower zone to grainflow (GF) dominated-fabrics in the upper zone.

Figure 5-15. Idealized fluid pathways based on facies elements with highly unrestricted flow in green, to highly restricted flow in red. Blue arrows represent likely flow pathways around the red-dashed relative baffles and barriers to flow. Note the variation in spatial scale of fluid pathways.

Figure 5-16. Northwest-southeast structural cross section through Covenant field. Modified from Schelling and others (2007), Chidsey and others (2007).

Figure 5.17. Cross-bedding in fine-grained sandstone deposited in an eolian dune environment of the Navajo Sandstone, from the Federal No. 17-3 well (slabbed core from 6776 feet), Covenant field. Also shown are early, bitumen and gouge-filled, silica-cemented, impermeable fractures that have slight offsets.

Figure 5-18. Representative photomicrographs from the Navajo Sandstone in the Federal No. 17-3 well. A – Bimodal distribution of subangular to subrounded quartz sand and silt (plane light) deposited in a vast eolian desert dune field. Note a few fractured and corroded K-feldspar grains are present. Blue space is intergranular porosity. Porosity = 14.8%, permeability = 149 mD based on core-plug analysis, 6773 feet. Courtesy of Wolverine Gas & Oil Corporation. B – Dolomite cement around a subangular microcline (striped gray) feldspar among bimodally distributed quartz grains (crossed nicols). Federal No. 17-3 well, 6757 feet. Courtesy of David E. Eby, Eby Petrography & Consulting, Inc.

Figure 5-19. Map showing locations of the Federal No. 17-3 well and the injection targets, which are three salt water disposal wells northwest of the Hunter Power Plant (courtesy Google Earth Pro).

Figure 5-20. Well log comparison between Covenant oil field and the Hunter Power Plant area.

Figure 5-21. Federal No. 17-3 core descriptions with the six locations of mercury porosimetry samples indicated by red dots and depths in bold. Note that relative permeability samples are also from this subset of the depths: 6805.2 feet, 6820.6 feet, and 6830.4 feet.

Figure 5-22. P- and S-wave velocity and Leeb Hardness measured on core samples of the Federal No. 17-3 well.

Figure 5-23. Capillary pressure curves for six samples from the Federal No. 17-3 core (in blue; see table 5-3) and two outcrop samples (in red and dashed).

Figure 5-24. Pore aperture distributions based on capillary pressure data for six samples from the Federal No. 17-3 core (in blue; see table 5-3) and two outcrop samples (in red and dashed).

Figure 5-25. Photomicrographs (plane polarized light) of three samples representative of ones used for relative permeability tests. Sample 129 is from 6820.6 feet, eolian dune lithofacies; sample 139 is from 6830.4 feet, small dune lithofacies; and sample 117 is from 6805.2 feet, and is eolian dune lithofacies. The red scale bar in each case is 1 mm.

Figure 5-26. Single phase permeability plotted as a function of effective pressure (left hand plots) and brine-CO_2 relative permeability (right hand plots) for samples 129 (top) and 117 (bottom).

Table 5-1. Lithostratigraphic facies and facies associations described and grouped.

Table 5-2. Basic petrophysical properties of outcrop hand samples from the Navajo Sandstone, San Rafael Swell.

Table 5-3. Federal No. 17-3 core plugs selected for relative permeability measurements. The porosity and permeability measurements were performed previously at 1400 psi net confining stress. All six plugs listed are horizontal in orientation.

Table 5-4. Porosity and permeability based on mercury porosimetry for Federal No. 17-3 core and outcrop samples.

Rocky Mountain CarbonSAFE Phase I

Appendix F

RESERVOIR SEALS BASED ON OUTCROPS OF THE MIDDLE JURASSIC CARMEL AND TEMPLE CAP FORMATIONS, NORTHERN SAN RAFAEL SWELL

RESERVOIR SEALS BASED ON OUTCROPS OF THE MIDDLE JURASSIC CARMEL AND TEMPLE CAP FORMATIONS, NORTHERN SAN RAFAEL SWELL

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INTRODUCTION

The Middle Jurassic Carmel Formation is well exposed over large areas of the gently dipping west flank of the San Rafael Swell (figure 6-1). Along the east flank this section is steeply dipping to near flat lying (figure 6-2). Based on the lithologic characteristics determined from regional correlations (figure 6-3), outcrop observations, and measured sections (figure 6-4, plates 6-1 through 6-5), the Carmel should also provide an effective seal for CO_2 injected into the underlying Navajo near the Hunter and Huntington Power Plants along the northwest flank of the San Rafael Swell.

The Middle Jurassic Temple Cap Formation is present in some areas of the San Rafael Swell (plates 6-2, 6-4, and 6-5). The Temple Cap was deposited in coastal dune, sabkha, and tidal flat environments. Where present, the Sinawava Member of the Temple Cap directly overlies the Navajo Sandstone and represents an additional potential seal. There are sections where the eolian White Throne Member lies on the Navajo making it difficult to separate the Navajo from the Temple Cap.

REGIONAL CORRELATIONS

The Carmel and Equivalent Formations

The Carmel Formation is widespread regionally and thus attests to its consideration as a seal for the Navajo Sandstone reservoir. The correlation of Middle Jurassic formations and their members as well as their lithofacies is summarized on figure 6-3. The strata naturally fall into three regions based on lithology: 1 – northern Utah, 2 – central Utah, and 3 – southwestern Utah. The central region includes the Carmel Formation in the San Rafael Swell and the equivalent Arapien Formation in the central Utah thrust belt to the west. The Carmel is equivalent to Twin Creek Limestone in the northern region. The colored boxes on figure 6-5 represent the general east-west lithofacies distribution and depositional environments. Note that the Twin Creek Limestone and Arapien Formation in the northern and western central regions, respectively, generally represent open, restricted, and marginal marine environments grading eastward and southeastward in the Carmel Formation to marginal marine, fluvial, and eolian environments.

Ages

Middle Jurassic isotopic ages for the Carmel and other Middle Jurassic formations in Utah are based on samples from volcanic ash beds (Kowallis and others, 2001, 2011; Sprinkel and others, 2009). The red dots on figure 6-3 represent the approximate stratigraphic position of radiometric ages obtained from sanidine, biotite, or zircon crystals, and palynomorph assemblage distribution. The age of the underlying Gypsum Springs Formation is 185 Ma in the northern region; the preferred age range of the Temple Cap Formation is 173 to 170 Ma in the central and southern regions; Sliderock, Rich, and Co-op Creek Limestone Members is 169 to 167 Ma; Boundary Ridge-Crystal Creek and Watton Canyon-Paria River Members is 166 to 165 Ma; and Leeds Creek-Giraffe Creek-Twelvemile Canyon-Winsor Members is 164 to 162(?) Ma. The numeric ages of the time boundaries are from Cohen and others (2013).

Unconformities

The Carmel Formation overlies the Temple Cap Formation, where it is present, or the Lower Jurassic Navajo Sandstone of the Glen Canyon Group. The Middle Jurassic Carmel (or Temple Cap) is separated from the underlying Navajo by the J-1 unconformity (figure 6-3) (Pipiringos and O'Sullivan, 1978). Recent research indicates the J-1 is a major regional unconformity representing a hiatus of over 10 million years (Kowallis and others, 2001, 2011; Sprinkel and others, 2009, 2011; Dickinson and others, 2010; Phillips and Morris, 2013). At the top of the Navajo, the J-1 is indicated by angular chert fragments, desiccation cracks, brecciation zones, carbonate nodules, bioturbation, and thick bleached intervals (Pipiringos and O'Sullivan, 1978); however, the J-1 can be very subtle in some areas. In addition, the upper Navajo contact undulates up to 200 feet over long distances, creating paleohighs and providing further evidence that the J-1 is a significant regional unconformity (Sprinkel and others, 2009; Anderson and others, 2010; Phillips and Morris, 2013).

The Carmel Formation and the underlying Temple Cap Formation were thought to be separated by the J-2 unconformity of Pipiringos and O'Sullivan (1978). However, age dating and stratigraphic work show that there is little evidence for the J-2 in the central and southern regions. The J-2 is present in the northern region where the Twin Creek Limestone lies unconformably on the Gypsum Springs Formation. Based on radiometric age dating, the J-2 may represent a gap of as much as 17 million years. Many exposures show no lithologic evidence of an unconformity (Anderson and others, 2010).

The Middle Jurassic Entrada Sandstone lies conformably above the Carmel Formation in the San Rafael Swell.

CARMEL FORMATION

The four members of the Carmel Formation—the Co-op Creek Limestone (or equivalent Judd Hollow), Crystal Creek, Paria River, and Winsor (figure 6-5)—are described in detail in the following sections. They have been mapped on the surface, measured, and described by Doelling and Kuehne (2008) and Sprinkel and Doelling prior to this study. All four members are not always present within the San Rafael Swell. The formation is highly heterolithic consisting of siliciclastics, carbonates, shales, and has numerous evaporite beds, all contributing to form an excellent seal.

The Carmel Formation is the result of deposition during the transgression of the shallow marine Sundance Sea, which extended south from Canada into a narrow embayment or arm (called the Utah-Idaho trough) through northern, central, and southwestern Utah (Blakey and Ranney, 2008; Hintze and Kowallis, 2009). Shoreline fluctuations produced variations between restricted- and more open- to marginal-marine conditions, causing significant changes in deposition. This was especially the case along the eastern margin of the marine embayment, which is now exposed within the San Rafael Swell. The Co-op Creek and Paria River Members correspond to marine transgressions and the Crystal Creek and Winsor Members represent regressions (Doelling and others, 2010a). Doelling and Kuehne (2008) suggest a possible unconformity (angular) separates the Crystal Creek and Paria River Members.

Co-op Creek Limestone/Judd Hollow Members

The basal Co-op Creek Limestone Member is exposed along the western half of the San Rafael Swell (figure 6-5) and the stratigraphically equivalent Judd Hollow Member is exposed on the east side (figure 6-6A), forming the classic dark flatirons on the lighter Temple Cap Formation and Navajo Sandstone along the steep east flank of the San Rafael Swell structure. The members are Bajocian in age and range in thickness from 33 to 80 feet. The Co-op Creek and Judd Hollow consist of interbedded sandstone, siltstone, mudstone, and limestone with subordinate amounts of dolomite, doloarenite, calcarenite, and calcisiltite. Limestone dominates the Co-op Creek whereas sandstone dominates the Judd Hollow, representing a gradational change in lithofacies from west to east across the San Rafael Swell area. Sandstone is light brown to light gray or yellow, friable, and composed of very fine to coarse-grained, generally calcareous, well-sorted, and subrounded to rounded quartz sand. Sandstone beds can be slightly planar to cross-stratified or bioturbated. Limestone is light and dark gray to yellow-gray or green gray to pink lavender, hard and densely crystalline (micritic) but can be silty or sandy. Limestone beds are often laminated and may display ripples, mudcracks, or some low-angle cross-beds. Some units are vuggy, oolitic, or bioclastic; megascopic fossils include pelecypods and a few gastropods. Siltstone is red to gray, calcareous and often nodular. Mudstone is medium to dark gray to green, slightly silty, calcareous, platy to fissile, with some fine and wavy laminations or flaser bedding. Shale is medium brown-gray or dark gray, clayey, fissile, non- to slightly calcareous. Calcite veins, nodules, as well as and blebs, chert can be present in many units. The Co-op Creek and Judd Hollow form steep slopes or blocky ledges with thin to medium bedding.

The Co-op Creek and Judd Hollow Members were deposited in moderate- to low-energy, normal-salinity, nearshore intertidal marine environments during transgression of the Sundance Sea into the Utah-Idaho trough. The Co-op Creek represents marine conditions, whereas the Judd Hollow represents marginal marine (tidal flat) settings.

Crystal Creek Member

The Crystal Creek Member (Bathonian) ranges in thickness from 0 to 36 feet. It consists of yellow, yellow-gray, or yellow-brown to light-gray sandstone and medium to dark red-brown, gray-pink siltstone (figures 6-5 and 6-6A). Sandstone is calcareous to dolomitic, very fine to medium grained, subrounded, well sorted, porous, and horizontally laminated. It is thin to medium bedded or massive, forming ledges or steep slopes that weather into pale red- or brown-colored plates that commonly contain ripple marks. Siltstone is nodular and calcareous or non-calcareous and it forms earthy slopes with indistinct or contorted bedding. Both sandstone and siltstone beds contain crisscrossing to subhorizontal satin spar gypsum veinlets.

The Crystal Creek Member was deposited during regression of the Sundance Sea. Environments included moderate- to low-energy, normal-salinity, nearshore intertidal marine.

Paria River Member

The Paria River Member (Bathonian) ranges in thickness from 15 to 170 feet. A few reworked, light-green, air-fall ash beds are present in the Paria River and contain very fine grained sand and small biotite and zircon crystals that provide Bathonian isotopic age dates (see Sprinkel and others, 2011).

The Paria River Member consists of a wide variety of light- to medium-gray, pink-gray, green-gray, brown-gray, yellow-gray or tan-gray lithotypes: sandstone, calcarenite, calcisiltite, limestone, mudstone, siltstone, and gypsum (figures 6-5 and 6-6A). Sandstone (calcareous) and calcarenite are very fine to fine grained, and well sorted; low-angle, small-scale planar cross-stratification, ripple marks, and bioturbation may be present; some calcarenite beds contains oolites. Limestone may be laminated, micritic, or finely crystalline, with silty, argillaceous, and dolomitic or vuggy zones. Pelecypods are found in limestone near the base of the Paria River. Some units contain ooids and ripple marks. The Paria River characteristically displays pencil weathering. Mudstone and siltstone beds are friable, usually calcareous, and in places contain low-angle trough cross-stratification. These lithotypes are generally thin to medium bedded, forming ledges (weathering into slabs and plates) and slopes. Gypsum, which forms the base of the member, is white alabaster, massive, and nearly pure.

The Paria River Member was deposited during a second major transgression of the Sundance Sea (Blakey and Ranney, 2008). Shallow-marine and coastal environments included restricted inner to outer shelf, oolitic shoal, sabkha, and tidal flat.

Winsor Member

The Winsor Member (Bathonian and lower Callovian, based on palynomorphs [Anderson and Lucas, 1994; Sprinkel and others, 2011]) ranges in thickness from 190 to 380 feet. It consists of two main informal units: the lower gypsiferous and the upper banded. The gypsiferous unit consists of interbedded red, red-brown, green-gray, or light-gray sandstone, calcarenite, calcisiltite, and siltstone, and white alabaster gypsum and a few limestone beds. Sandstone is friable, fine grained, well sorted, and cemented with calcite or iron oxide. Calcarenite is very fine grained, well sorted, and laminated to thin bedded with well-developed ripple marks and some bioturbation. Calcisiltite appears shaly and weathers into small plates. Siltstone is coarse grained, gypsiferous (often with fine laminae of gypsum), and contains small lenses of calcarenite. Sandstone and siltstone beds form steep earthy slopes. Gypsum is silty and forms ledges as much as 20 feet thick. The banded unit consists of interbedded sandstone, calcarenite, siltstone, and mudstone that display colored bands of red and gray in various shades, and white gypsum. These rocks have characteristics similar to those in the underlying gypsiferous unit. Gypsum veins crisscross the clastic rocks. Gypsum beds produce frothy “popcorn-like” or sugary weathering on sparsely vegetated surfaces and drape into drainages (Rigby and others, 1974).

The Winsor Member was deposited in restricted, muddy, hypersaline marine and coastal environments during a second major regression of the Sundance Sea (Blakey and Ranney, 2008).

TEMPLE CAP FORMATION

Outcrops of the Temple Cap Formation within the San Rafael Swell range in thickness from 0 to 60 feet, possibly due to pinchouts against paleohighs of the underlying Navajo Sandstone along the J-1 unconformity (figure 6-6) (Hintze and Kowallis, 2009; Anderson and others, 2010; Doelling and others 2013). The Temple Cap is divided into the three members: the Sinawava (basal marine), White Throne (eolian), and Esplin Point (capping marine) Members (Sprinkel and others, 2009, 2011; Biek and others, 2010). The White Throne and a few very thin beds of the Sinawava are observed in outcrop at the San Rafael Swell (figure 6-6, plates 6-2, 6-4, and 6-5); most of the Sinawava and Esplin Point are present in the subsurface in wells at Farnham Dome gas field and others in the northern part of the San Rafael Swell.

Sinawava Member

The Sinawava Member of the Temple Cap Formation is a heterogeneous, generally 0 to 50-foot-thick section; note that the Sinawava is not present in the outcrop measured sections closest to the Hunter Power Plant (figure 6-4, plates 6-3 and 6-4). This unit is characterized by low-angle to horizontal laminae (figure 6-6) or distorted bedding consisting of red-brown, very fine to fine-grained, thin, poorly sorted sandstone to mudstone, limestone, and gypsum (Sprinkel and others, 2009). Horizontal stratification often contains silty laminae between beds. These beds may also display ripples or channel characteristics (scour) suggesting tidal flow or flooding events.

The Sinawava Member represents a brief time of coastal sabkha and tidal flat environments. This interpretation is supported by the presence of glauconite in sandstone from cores at Covenant field (located about 50 miles west of the San Rafael Swell) indicating marine to marginal marine conditions.

White Throne Member

The White Throne Member of the Temple Cap Formation is homogeneous, generally 0 to 200-foot-thick section; the White Throne is not present in the outcrop measured section along the San Rafael River southeast of the Hunter Power Plant (figure 6-4, plate 6-3) but is present directly east (plate 6-4). It consists of light gray-pink, light-brown, yellow-brown, light red-brown, light-gray, gray, or white sandstone composed of fine- to coarse-grained, moderately sorted quartz sand (figure 6-6). The sandstone is friable, poorly cemented with calcite and/or iron oxides, porous, and locally saturated with dead oil. The White Throne forms cliffs and resistant benches that are medium to thick bedded and partly cross-stratified (Doelling, 2002, 2004; Doelling and Kuehne, 2008).

The White Throne Member was deposited under eolian conditions as a coastal dune field (Blakey, 1994; Peterson, 1994; Blakey and Ranney, 2008). White Throne dunes were smaller than Navajo dunes (widths up to 1650 feet) (Hartwick, 2010). Regional analyses of the mean dip of dune foreset beds from outcrop and Covenant field core indicate paleowind directions were dominantly from the northeast (Peterson, 1988; Hartwick, 2010). About half of the oil production at Covenant field is from the White Throne, the rest coming from the Navajo Sandstone. The

White Throne produces nowhere else at this time.

Esplin Point Member

The Esplin Point Member capping the Temple Cap has characteristics similar to the basal Sinawava Member. It ranges in thickness from 0 to 12 feet and consists of dark red-brown, light-gray, and green-gray siltstone and sandstone. Sandstone beds are very fine to fine grained, well sorted, and thinly laminated to irregularly bedded. Siltstone beds are thinly laminated and form slopes and recesses. The Esplin Point Member documents a rise in sea level and a return to coastal sabkha, tidal flat, and nearshore marine conditions.

DISCUSSION

Carmel Formation Seals

The Carmel Formation is a proven seal for the naturally occurring CO_2 stored in the Navajo Sandstone reservoir at Farnham Dome gas field on the north end of the San Rafael Swell. Based on outcrops throughout the northern Swell, the members of the Carmel contain various beds that would provide a seal for CO_2 injected into the Navajo near the Hunter and Huntington Power Plants.

Foremost among the sealing Carmel lithologies are the multiple, massive gypsum ($CaSO_4 \cdot 2H_2O$) beds found in the Paria River and Winsor Members. The Carmel gypsum beds are fairly continuous (plates 6-1 through 6-5). The Paria River typically contains a basal gypsum unit that is 6 feet or greater in thickness (plates 6-1 and 6-2). However, the Winsor contains six to nine gypsum beds ranging in thickness from 1 to 20 feet; total thickness ranges from 50 to 90 feet in outcrops east and southeast of the Hunter and Huntington Power Plants (figures 6-1 and 6-4, plates 6-3 and 6-4). Gypsum is produced from one mine in the Winsor Member on the west flank of the San Rafael Swell and is used for manufacturing wallboard (sheetrock) and plaster (Gloyn and others, 2003). The Carmel contains an estimated 7.3 million tons of minable gypsum. Cumulative gypsum production from the Winsor in the San Rafael Swell since 1990 is about 1.8 million tons (verbal communication, Andrew Rupke, Utah Geological Survey, 2018).

The Judd Hollow/Co-op Creek, Crystal Creek, and Winsor Members of the Carmel Formation contain numerous beds of mudstone and shale that can also serve as a reservoir seal to the Navajo Sandstone below. Individual shale/mudstone beds range in thickness from just a few feet to 45 feet; total thickness ranges from 13 to 70 feet. However, mudstone and shale are more prevalent to the south and southeast of the power plants (plates 6-1, 6-2, and 6-5).

The members of Carmel also include many beds of low-permeability crystalline limestone, marl, and siltstone that are likely barriers to fluid and gas migration.

Core was not available for the Carmel Formation, which is preferred for assessing petrophysical and sealing properties. The Site Characterization team was limited to using outcrops samples for preliminary sealing capacity estimates based on mercury intrusion capillary pressure (MICP) measurements (following methods presented in Chapter 5 for mercury porosimetry). Sealing capacity can be expressed as the height of a non-wetting phase held by capillary forces before it penetrates a rock that is saturated with the wetting phase (Dullien, 1992). To convert mercury capillary pressure curves to sealing capacity in terms of CO_2 columns heights, we follow methods of Dewhurst et al. (2002) to obtain breakthrough pressures, and we assume: 10° and 140°, respectively for the air-mercury-rock and water-CO_2-rock systems; 27 and 480 mN/m for the interfacial tensions of the CO_2-water and air-mercury systems; and water/brine and CO_2 densities of 1,020 and 740 kg/m^3, respectively. The values of CO_2-brine and contact angles for the rock-water-CO_2 system can vary greatly as a function of pressure, temperature, and mineralogy, and thus our choices should be considered preliminary. CO_2 column heights for Carmel Formation samples range from 3 to 1151 m (Table 6-1). These samples were collected from the Buckhorn Wash and Justensen Flats study areas (see Chapter 5). The CO_2 column heights confirm that the Carmel Formation has lithologies with high capillary sealing capacity. Note that the outcrop samples may have undergone weathering, and thus subsurface samples may have different (and probably higher) sealing capacity. The Carmel Formation capillary pressure curves and pore aperture distributions are generally distinct, as expected, from the Navajo Sandstone samples (Figure 6-7).

Temple Cap Formation Seals

The Sinawava and Epslin Point Members of the Temple Cap Formation, where present, also contain lithologies similar to those in the Carmel Formation that serve as seals. These include low-permeability siltstone, mudstone, limestone, and some gypsum. Units are generally thin, 2 to 5 feet thick.

CHAPTER 6 FIGURE CAPTIONS

Figure 6-1. Generalized geologic map of the San Rafael Swell with the Carmel and Temple Cap Formations highlighted in blue. Cross section A-A' shown on figure 6-2. After Doelling and Hylland (2002).

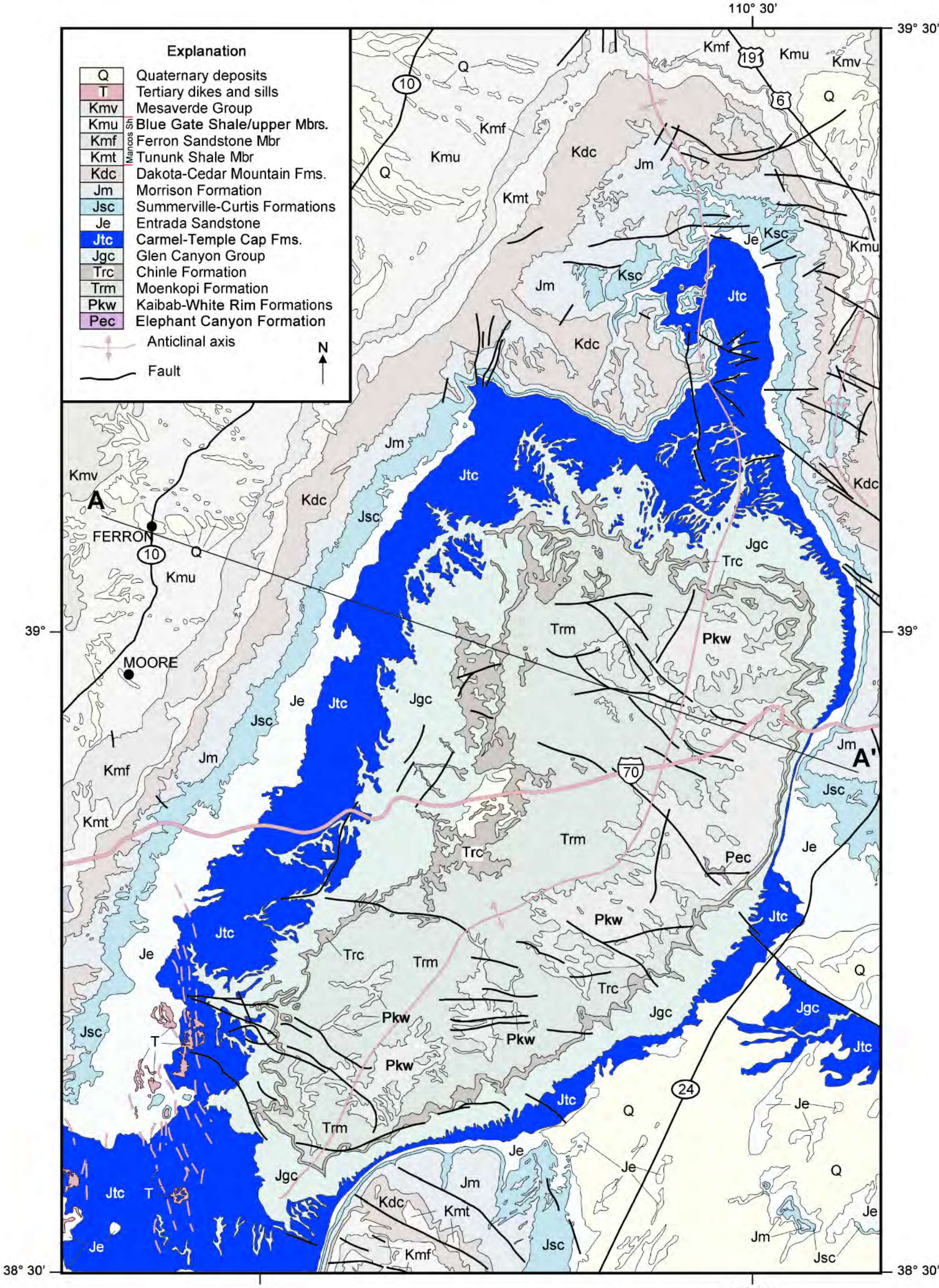
Figure 6-2. Diagrammatic cross section across the middle of the San Rafael Swell with the Carmel and Temple Cap Formations highlighted in blue. The cross section is not drawn to scale, and the vertical dimension is exaggerated about eight times relative to the horizontal. The horizontal length of the cross section covers about 50 miles. Symbols and colors of geologic formations correspond to those shown on figure 6-1; location of cross section also shown on figure 6-1. After Doelling and Hylland (2002).

Figure 6-3. Correlation chart of Middle Jurassic formations and their members in central Utah and the Sevier thrust belt. Modified from Sprinkel and others (2011); compiled from Kowallis and others (2001), Dickinson and others (2010), Sprinkel and others (2011), Doelling and others (2013), Sprinkel, Doelling, Kowallis, Waanders, and Kuehne, 1998-2017 unpublished data, Utah Geological Survey; numeric boundary ages from Cohen and others (2013).

Figure 6-4. Map of the San Rafael Swell showing the location of measured stratigraphic sections (plates 6-1 through 6-5) of the Middle Jurassic Carmel Formation. Also shown are major physiographic features, major towns, highways, and coal-fired power plants.

Figure 6-5. Excellent exposure of Middle Jurassic Carmel Formation, San Rafael Group, west flank of the San Rafael Swell, Devils Canyon south of I-70, view to the east. The Co-op Creek, Crystal Creek, Paria River, and part of the Winsor Members are shown. The Carmel is in direct contact with the underlying Navajo Sandstone represented by the J-1 unconformity. Note: the Temple Cap Formation is not present at this locality. Photograph by Michael Chidsey, Sqwak Productions Inc.

Figure 6-6. Middle Jurassic Temple Cap and Carmel Formations, east flank of the San Rafael Swell, north side of Black Dragon Canyon north of I-70. A – Thin Sinawava and planar to cross-stratified White Throne Members of the Temple Cap Formation separated from the underlying Navajo Sandstone by the J-1 unconformity. The Temple Cap is overlain by the red Judd Hollow-Crystal Creek Members of the Carmel Formation. B – Close-up view of the J-1 unconformity, and thin planar bedding in the Sinawava and White Throne Members. Photographs by Michael Chidsey, Sqwak Productions Inc.



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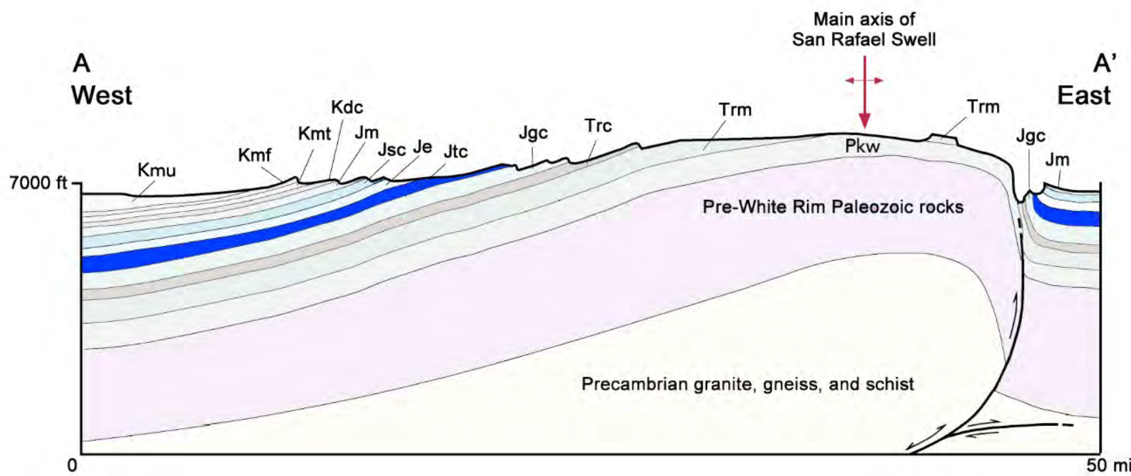

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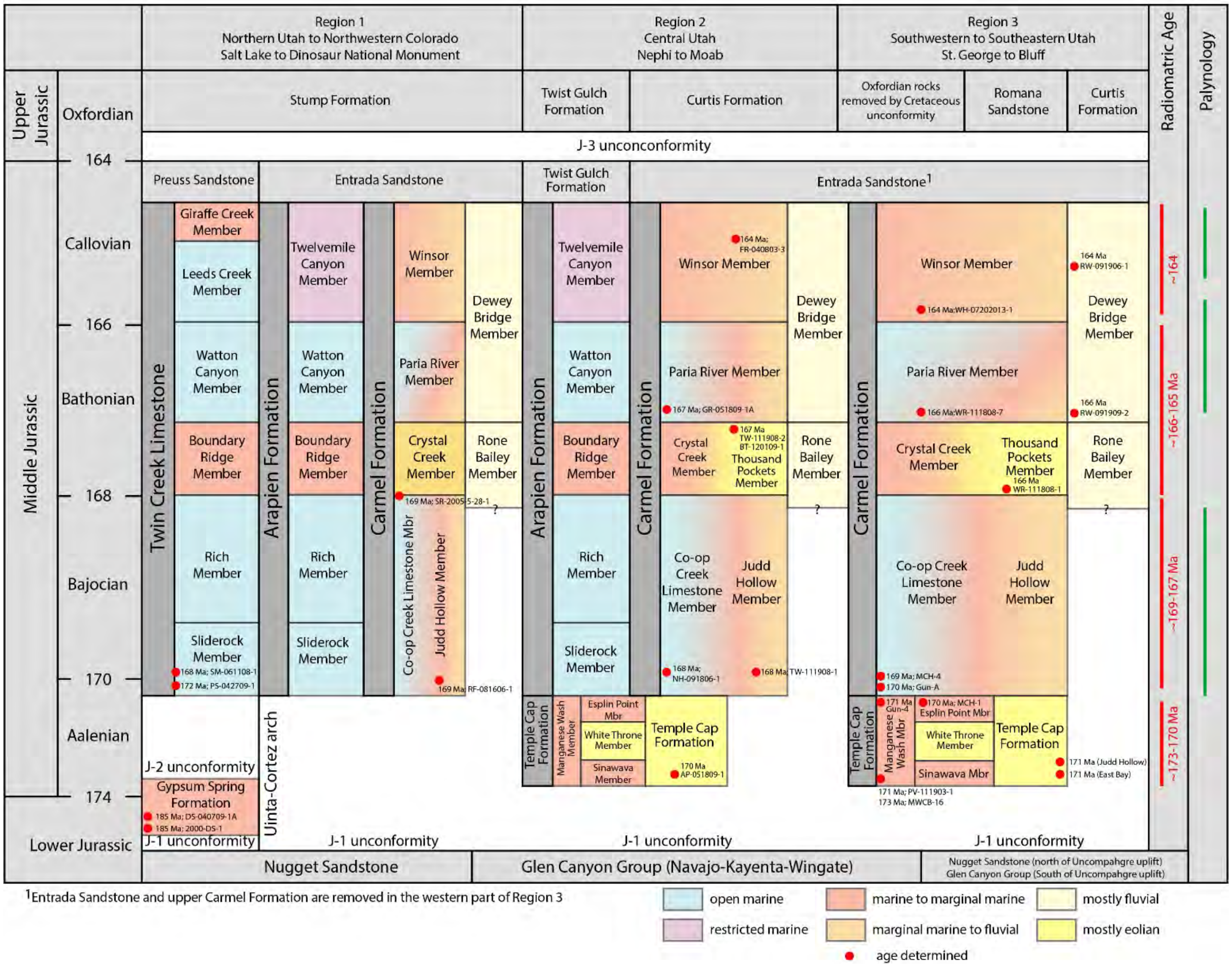

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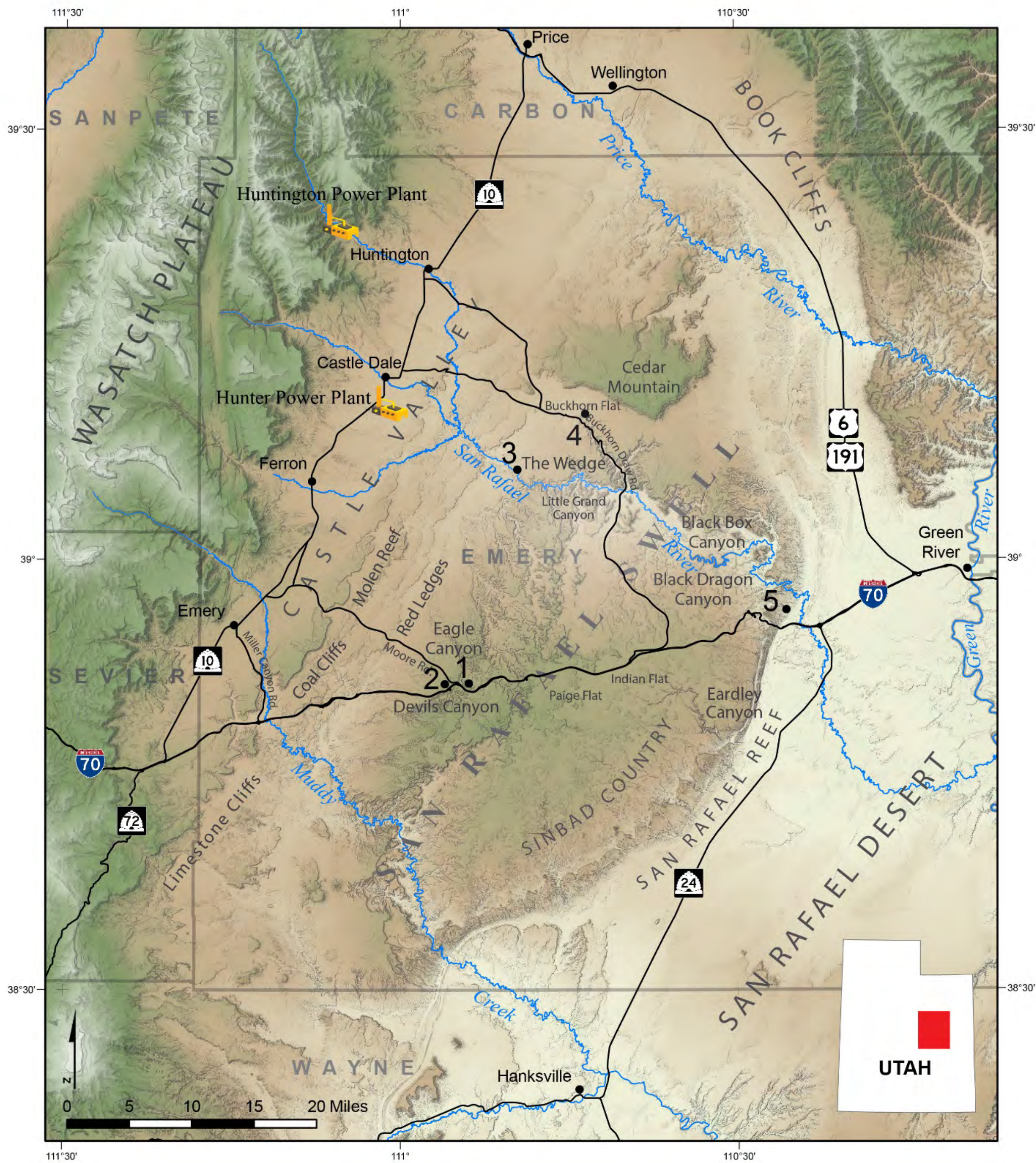


Figure 6-4. Map of the San Rafael Swell showing the location of measured stratigraphic sections (plates 6-1 through 6-5) of the Middle Jurassic Carmel Formation. Also shown are major physiographic features, surrounding towns, highways, and coal-fired power plants.

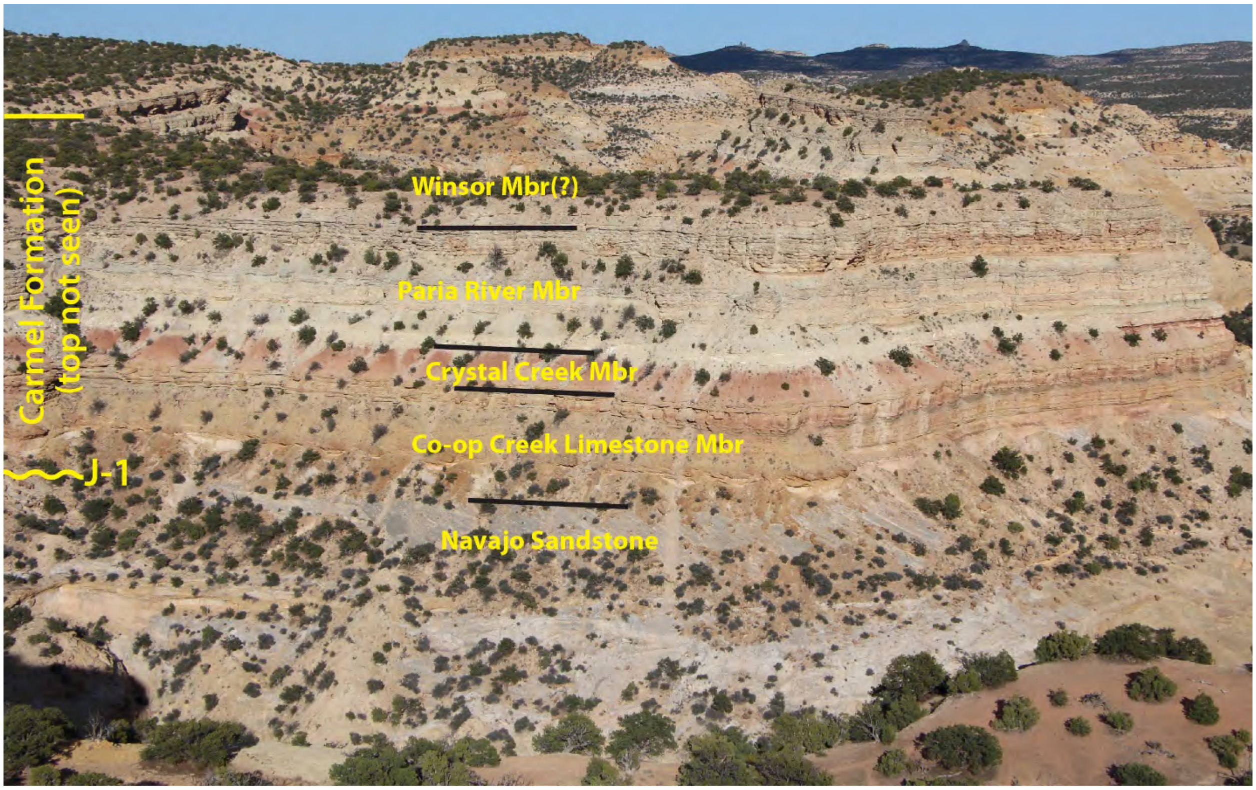
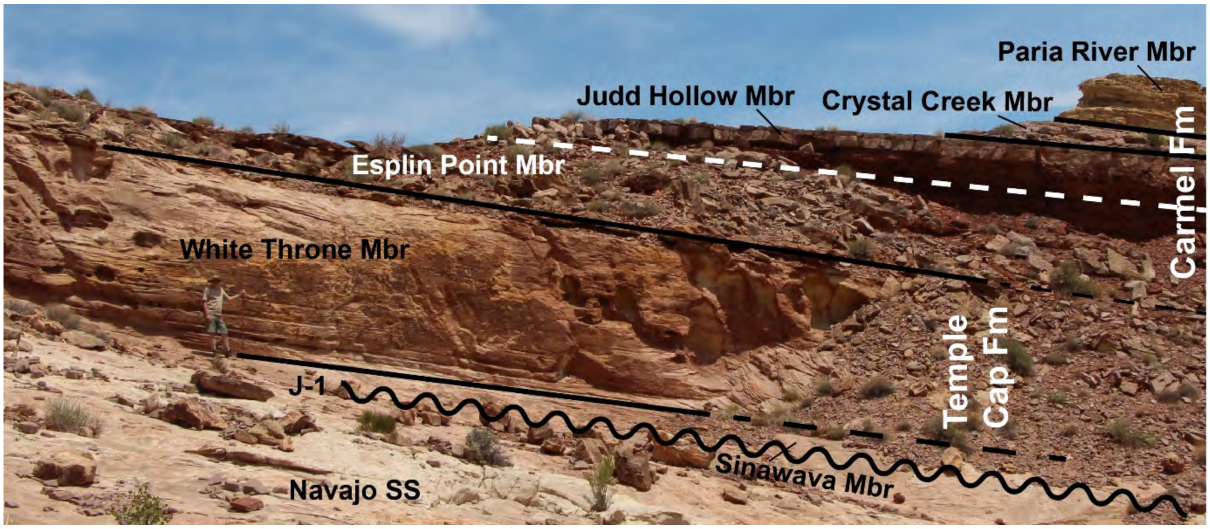


Figure 6-5. Excellent exposure of Middle Jurassic Carmel Formation, San Rafael Group, west flank of the San Rafael Swell, Devils Canyon south of I-70, view to the east. The Co-op Creek, Crystal Creek, Paria River, and part of the Winsor Members are shown. The Carmel is in direct contact with the underlying Navajo Sandstone represented by the J-1 unconformity. Note: the Temple Cap Formation is not present at this locality. Photograph by Michael Chidsey, Sqwak Productions Inc.

A



B

Figure 6-6. Middle Jurassic Temple Cap and Carmel Formations, east flank of the San Rafael Swell, north side of Black Dragon Canyon north of I-70. A – Thin Sinawava and planar to cross-stratified White Throne Members of the Temple Cap Formation separated from the underlying Navajo Sandstone by the J-1 unconformity. The Temple Cap is overlain by the red Judd Hollow-Crystal Creek Members of the Carmel Formation. B – Close-up view of the J-1 unconformity, and thin planar bedding in the Sinawava and White Throne Members. Photographs by Michael Chidsey, Sqwak Productions Inc.

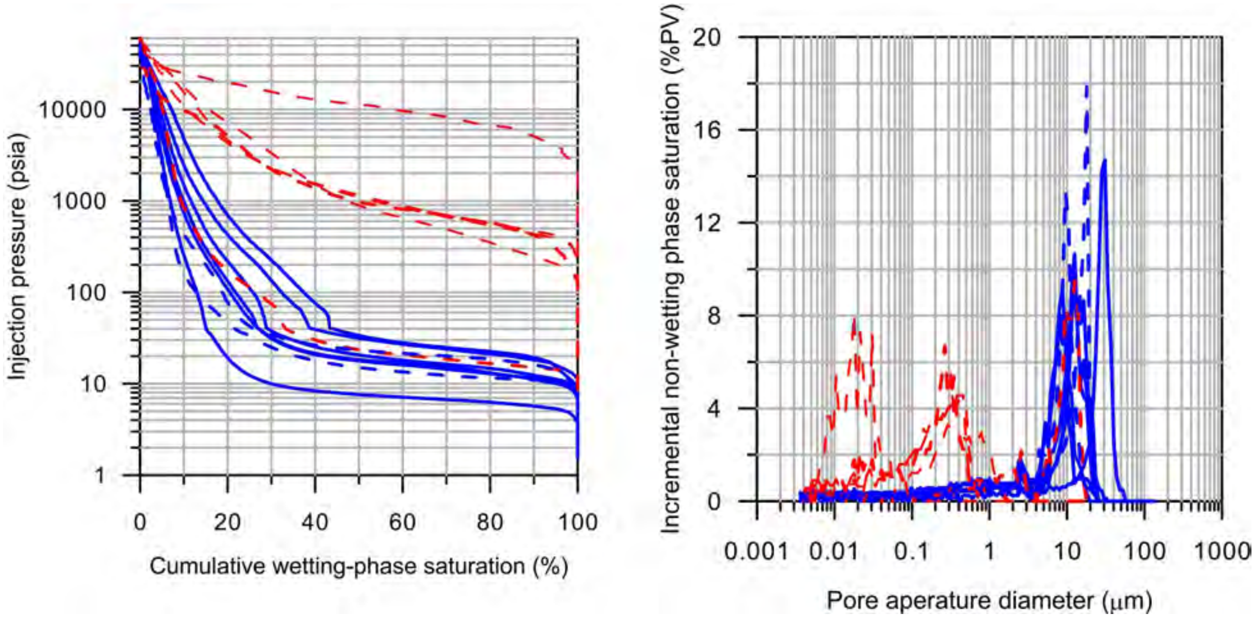


Figure 6-7. Left: Mercury intrusion capillary pressure curves (left) for Navajo Sandstone and Carmel Formation samples. Right: Pore aperture size distributions converted from the capillary pressure curves. Core samples are solid lines, and outcrops samples are dashed lines. Blue represents Navajo Sandstone samples, and red is for Carmel Formation samples. The Navajo Sandstone data from figure 5-23 is reproduced here for comparison to the Carmel Formation data. PV stands for pore volume.

Table 6-1. Samples and mercury capillary pressure results used to estimate CO_2 column heights.

Study area	**Sample ID**	**Formation /lithology**	**Mercury breakthrough pressure (psia)**	**Breakthrough pore aperture diameter (µm)**	**Breakthrough pressure, water-CO2 (psia)**	**CO2 column height (m)**
Buckhorn Wash	Sample 3 Basal Judd Hollow	Carmel, Judd Hollow member (basal above J1), fossiliferous calcarenite	15.56	13.713	1.13	2.83
Justensen Flat	Sample 15 JF2	Carmel, Judd Hollow member, probable calcarentie	614.69	0.347	44.45	111.61
Justensen Flat	Sample 19 JF1	Carmel, Judd Hollow member (basal above J1), probable dolomite	428.25	0.489	30.97	77.76
Justensen Flat	JC Red Bed	Carmel	428.29	0.489	30.97	77.77
Justensen Flat	JC First Limestone	Carmel, limestone	226.95	0.940	16.41	41.21
Justensen Flat	JC Sandstone	Carmel, sandstone	6340.59	0.034	458.51	1151.30
Study area	Sample ID	Formation / lithology	Mercury breakthrough pressure (psia)	Breakthrough pore aperture diameter (µm)	Breakthrough pressure, water-CO2 (psia)	CO2 column height (m)
Buckhorn Wash	Sample 3 Basal Judd Hollow	Carmel, Judd Hollow member (basal above J1),	15.56	13.713	1.13	2.83

		fossiliferous calcarenite				

Rocky Mountain CarbonSAFE Phase I

Appendix G

COMPILED FLUID GEOCHEMISTRY FOR POTENTIAL CARBON SEQUESTRATION RESERVOIRS IN CASTLE VALLEY

COMPILED FLUID GEOCHEMISTRY FOR POTENTIAL CARBON SEQUESTRATION RESERVOIRS IN CASTLE VALLEY

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INTRODUCTION

Fluid chemistry places basic constraints on development of carbon storage reservoirs. Beneath the Hunter and Drunkards Wash sites (figure 1-2), potential storage reservoirs include the Navajo Sandstone, White Rim Sandstone, Kaibab Limestone, and Redwall Limestone as described previously. This chapter presents compiled major ion chemistry for these reservoirs taken from a larger compilation of available major ion chemistry from both produced water and groundwater in the greater Uinta Basin area, which includes parts of the San Rafael Swell and the Wasatch Plateau (Chidsey, 2017).

The sample set covers an area that includes Emery County, Utah, and adjoining areas to provide representative samples near the Hunter site (figure 7-1). The data were taken from the National Water Information System (NWIS) database (U.S. Geological Survey, 2018). Each sample in the database includes data source, basic location information, and a unique identifier (Chem ID) that correlates to the geochemical database presented by Chidsey (2017). General data fields include a site name, site number, altitude, depth of sample, and date of sampling. The altitude is the land surface elevation in feet derived from the 5 meter (16.4 feet) digital elevation model for Utah for a given location. The depth of the sample is listed as a discrete value in feet below land surface. Samples are categorized into four simplified geologic units based on geologic information in the original data source. The simplified geologic units are Navajo Sandstone, White Rim Sandstone, Kaibab Limestone, and Redwall Limestone. Fields that have no data are given with the value -9999.

Sample chemistry fields in the database include temperature, pH, conductivity, total dissolved solids (TDS), and chemical concentration values. Solute concentrations for CO_2, HCO_3, Ca, Mg, Na, K, SO_4, F, and SiO_2, are in mg/L. The concentration of As is µg/L. The milliequivalent concentration of each major solute in the database was calculated using standard methods with the AquaCHEM™ software. Milliequivalent concentrations were used to calculate charge balance of the percent difference between the sum of charge equivalents for major anions and cations.

Geochemical samples were subdivided based on calculated water type or hydrochemical facies. Water type was calculated for all samples using AquaCHEM™ geochemical software based on standard methodologies by Kehew (2000). Water type is listed in both long and short forms in separate database fields. The long water type lists the two or three major anions and cations for a given sample, and the short water type provides only the single anion and cation with greatest relative concentration.

DATA SUMMARY

A total of 25 samples were chosen to represent the target reservoirs in fluid geochemistry (tables 7-1 and 7-2). These include ten samples from the Navajo Sandstone, six samples from the White Rim Sandstone, two samples from the Kaibab Limestone, and seven samples from the Redwall Limestone. Depths of the samples range from several hundred feet to greater than 8000 feet (figure 7-2). Most Navajo samples are from groundwater supply wells with depths less than 1000 feet. Samples of the Kaibab and the Redwall likely represent samples from oil/gas exploration wells. The samples from the White Rim include two shallow water wells and a single sample from a deeper oil/gas exploration well. None of these exploration wells are currently producing hydrocarbons.

TDS is a basic measure of the dissolved chemical load in a given sample. Figure 7-2 shows TDS versus depth for these samples. TDS concentration increases with depth for the Redwall Limestone. Deep samples from the Redwall have relatively high TDS values between 10,000 and 20,000 mg/L. Samples from the other geologic units do not show clear trends with depth and generally have TDS concentrations less than 10,000 mg/L.

Major ion chemistry is both a product and driver of water-rock interaction, scaling, corrosion, and ultimately the use of a fluid. Major ion chemistry ranges from $CaHCO_3$ for a single shallow sample from the White Rim Sandstone to $CaSO_4$ for most of the Navajo Sandstone samples to NaCl type typical of the deeper samples from the Kaibab and Redwall Limestones. A piper diagram of the samples (figure 7-3) shows that chemistry spans a wide range from water dominated by calcium and sulfate to water dominated by sodium and chloride. These chemical differences are most prominent between the calcium and sulfate-dominated water typical of shallow Navajo sandstone and sodium- to chloride-dominated water found in deeper samples from the limestone units (Kaibab and Redwall). Variation in chemistry in these units is controlled by sulfate, sodium, and chloride concentrations that are likely driven by water-rock interaction in the case of the shallow samples. Chemistry of the deeper samples may also be influenced by additional interaction with hydrocarbons. Ultimately in situ fluid chemistry in potential carbon storage reservoirs will control the total potential storage in a given unit due to CO_2 saturation and mineral composition of the host rocks.

CHAPTER 7 FIGURE AND TABLE CAPTIONS

Figure 7-1. Sample location map of selected fluid geochemical samples. These samples are a subset of the database found in Chidsey (2017).

Figure 7-2. Graph of sample depth versus total dissolved solids (TDS).

Figure 7-3. Piper diagram of selected samples.

Table 7-1. Location and sample parameters of selected samples.

Table 7-2. Compiled fluid chemistry of selected samples. See table 7-1 for sample locations.

Table 7-1. Location and sample parameters of selected samples.

Chem ID	Location		Formation	Depth	Temperature	Conductivity	pH
	Northing	Easting		(ft)	(C°)	(µs/cm)	
105	4299086	509604	White Rim Sandstone	-9999	-9999	1650	7.20
232	4329146	513555	Navajo Sandstone	475	13	870	7.00
241	4271381	525799	Navajo Sandstone	400	-9999	1550	7.00
279	4269190	524911	Navajo Sandstone	802	-9999	1300	7.10
320	4270788	492558	Navajo Sandstone	767	-9999	2840	7.80
331	4258684	587367	White Rim Sandstone	500	13	2870	7.70
334	4270788	492558	Navajo Sandstone	-9999	18	3050	6.70
335	4270788	492558	Navajo Sandstone	-9999	-9999	-9999	-9999.00
338	4258684	587367	White Rim Sandstone	500	13	2830	7.60
376	4260997	484919	Navajo Sandstone	-9999	-9999	-9999	-9999.00
408	4259010	591677	White Rim Sandstone	581	20	2970	7.70
493	4259040	594270	White Rim Sandstone	-9999	20	2560	8.00
503	4293026	517211	Redwall Limestone	2197	-9999	6060	7.50
637	4295548	574661	White Rim Sandstone	2510	-9999	4230	7.10
728	4251688	526469	Navajo Sandstone	750	18	5290	7.60
833	4350371	543433	Navajo Sandstone	353	16	12800	6.10
874	4251881	548173	Redwall Limestone	6820	-9999	22700	7.40
915	4294952	562798	Redwall Limestone	7702	-9999	35500	6.90
953	4336949	551546	Kaibab Limestone	3373	-9999	55000	7.40
960	4324304	488379	Kaibab Limestone	7224	-9999	-9999	7.80
972	4374453	544374	Redwall Limestone	8080	-9999	-9999	6.20
976	4258815	481668	Navajo Sandstone	950	16	82000	7.00
986	4288639	555436	Redwall Limestone	6353	-9999	-9999	7.70
987	4299578	573828	Redwall Limestone	8715	-9999	186000	6.40
991	4295548	574661	Redwall Limestone	8440	-9999	220000	6.90

Rocky Mountain CarbonSAFE Phase I

Appendix H

Hydrodynamics

HYDRODYNAMICS

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INTRODUCTION

Two regionally extensive formations, the Upper Triassic Lower Jurassic Glen Canyon Group (particularly the Lower Jurassic Navajo Sandstone) and the Middle Jurassic Carmel Formation in outcrops in the San Rafael Swell and subsurface of Castle Valley, are considered in this chapter. The Middle Jurassic Entrada Sandstone and Cretaceous Dakota Formation are well exposed on the western side of the Swell. The Entrada and Dakota are considered locally as good quality aquifers with bracketing confining units. However, they are not considered to be good candidates for CO_2 injection because they are not deep enough, greater than 3000 ft. measure depth, to have the necessary hydrostatic pressure in the Hunter and Drunkards Wash study areas. Most hydrogeologic researchers consider the Navajo Sandstone, Kayenta Formation, and Wingate Sandstone of the Glen Canyon Group to be significant water-bearing aquifers. The Navajo is considered as the primary aquifer in the Glen Canyon Group because its porosity and permeability are considerably higher than that of the Kayenta and Wingate, which are mentioned here because several injection wells at Buzzards Bench field are perforated in the Kayenta Formation and Wingate Sandstone along with the entire thickness of the Navajo Sandstone.

PREVIOUS STUDIES

The regional hydrogeology of Castle Valley and the San Rafael Swell have been studied by several investigators. Hood and Patterson (1984) studied the bedrock aquifers, particularly the Navajo Sandstone, and provided regional aquifer parameters deduced from several wells that produced from each aquifer. Several formations were defined as regional aquitards. Freethey and Cordy (1991) reviewed the hydrogeology of the Mesozoic rocks in the upper Colorado River Basin in Utah, Colorado, and Wyoming, and confirmed the earlier aquifer properties of Hood and Patterson (1984) and added additional aquifer properties from the Glen Canyon Group (Navajo/Nugget Sandstone) and Carmel Formation. Freethey and Stolp (2009) also looked at the flow and solute transport in the Glen Canyon Group aquifers in the San Rafael Swell region. Gloyn and others (2003) summarized the groundwater conditions in the western San Rafael Swell and Wasatch Plateau. Randall (2009) investigated the suitability of the Navajo Sandstone for saline water disposal and CO_2 injection in the Drunkards Wash and Buzzard Bench areas. Montgomery Watson (2009) submitted results of injection modeling into the Navajo Sandstone via salt water disposal wells at Buzzard Bench (within the Hunter study site). A report by Stim-Lab (1997) described the pore pressure regime and fracture permeability in the Navajo Sandstone and anhydrites in the lower Carmel Formation in the Hunter study site. This chapter will be referring to all the above studies while summarizing the hydrogeologic properties of the Carmel Formation and Navajo Sandstone.

HYDROGEOLOGY OF THE NAVAJO SANDSTONE

The Navajo Sandstone is considered the primary aquifer on the western side of the San Rafael Swell and Castle Valley region, particularly in the Drunkards Wash and Hunter study areas. The sandstone is 300 to 600 ft thick below the Hunter study area and 300 to 400 feet thick below the Drunkards Wash study area (figure 2-8). The Navajo outcrops approximately 11 miles southeast of the Huntington Power Plant and has 5.5 miles of exposed surface measured along the dip (figure 1-2). This is a very large surface area for recharge into the sandstone. The sandstone is very fine to fine grained at the bottom of the formation and coarsens to medium grained at the top of the formation (for a detailed description refer to chapter 5). The eastern Navajo recharge area is topographically higher than the sandstone at the Hunter and Drunkards Wash sites. Groundwater bifurcates at a divide south of the Hunter site near the southern end of the San Rafael Swell and flows towards the Dirty Devil River drainage. The groundwater recharge, southeast of Castle Dale, flows northwest towards Huntington (figure 8-1) then north and northeast around the northern nose of the San Rafael Swell.

Porosity and Permeability

Hood and Patterson (1984) indicated that the permeability of the Navajo Sandstone in the northern San Rafael Swell area ranges from very low to moderate. Several Navajo facies were observed, and outcrop samples were collected and plugged (figure 8-2) for permeability and porosity testing. Samples were collected from each sandstone facies including avalanche, wind ripple facies, and interdune. Porosities range from 7.9% in the fine-grained interdune facies to 18.7% in the coarse-grained, well-sorted wind ripple facies (see table 5-2). These results agree very well with very low to moderate porosity reported by Hood and Patterson (1984). It is important to note that the Navajo Sandstone porosity is not much higher than the porosity measured in the Carmel Formation limestone and siltstone beds at the lower contact. The permeability measured from the Navajo outcrop plugs ranges from 17.7 mD in the interdune to 1375 mD in the wind ripple facies. The permeability is three orders of magnitude greater in the Navajo compared to the overlying Carmel.

Hydraulic Conductivity

Hydraulic conductivity (K) is a measure of the ease that a fluid transfers through a medium. K is a function of matrix intrinsic permeability, matrix fluid saturation, fluid density, and viscosity. Hydraulic conductivity is measured in the lab or determined from flow testing. Hood and Patterson (1984) reported measured K values ranging from 0.0037 to 5.1 ft/d from several short-term aquifer tests from wells in the Navajo Sandstone in the region. Transmissivities from the same aquifer tests ranged from 27 to 643 ft^2/day. Specific Yield is between 5% and 10%. These aquifer parameters were not correlated to a sandstone facies identified in this study.

Fracturing

Fracturing is observed in most of the Navajo Sandstone outcrops on the west side of the San Rafael Swell. Fracturing occurred during tensional uplifting in the Navajo (see chapters 5 and 6). Many fractures are filled with calcite, gypsum, or silica cement. Cores from the Navajo at the Federal No. 17-3 well in Covenant field have both filled and open fractures. Near the recharge areas and progressing downward from the top of the Navajo, fractures are probably filled with precipitated cement. Fractures deeper in the Hunter and Drunkards Wash study sites may be open and fluid filled. The study by Stim-Lab (1997) showed a step-rate test at disposal well SWD No. 1 suggesting short-length fractures enhance permeability in the Navajo and that the aquifer is underpressured. There is probably a significant component of fracture flow in the overall permeability of the Navajo in the Hunter and Drunkards Wash study sites.

HYDROGEOLOGY OF THE CARMEL FORMATION

The Carmel Formation varies from 600 to 1000 feet thick (see figure 2-23) in the Hunter and Drunkards Wash study sites and at the recharge area. The Carmel is widely exposed 8.5 miles southeast of the Hunter Power Plant, reaches a maximum of 700 feet in thickness (Hintze and Kowallis, 2009), and has approximately 4.5 miles of exposed formation, measured along dip. As described in chapter 6, it consists of interbedded siltstone, mudstone, carbonaceous mudstone, limestone, and evaporites (gypsum and anhydrite) which are generally fluid flow and fracture barriers. Almost all recharge to the Carmel occurs at outcrops southeast of the Hunter and Drunkards Wash study sites on the western side of the San Rafael Swell and is primarily from snow melt and heavy spring rains. Annual precipitation at the recharge area is between 6 and 8 inches (Hood and Patterson, 1984). Locally, heavy thunderstorms are common in this region but contribute a very small amount of recharge to the formation as storm runoff because it either evaporates or flows to the local washes and into the San Rafael River. The formation can be a locally good, perched aquifer with several low-flow springs and shallow wells with water sourced from the carbonates and siltstones. Most recharge in the Carmel moves west to northwest saturating the aquifer and discharging as perched springs or from shallow wells.

Porosity and Permeability

Four outcrop samples were collected from the lower part of the Carmel Formation and analyzed for porosity and permeability (figure 8-2). Vertical and horizontal porosity and permeability were measured for all samples. Table 6-1 shows the analytical results of the Carmel Formation plug samples. Vertical porosity ranges from 5% to 16.1% and the highest porosity is in the limestone. The lower sandstone sample has the lowest porosity. Two horizontal samples from the limestone and Judd Hollow samples have 13.9% and 8.4% porosity, respectively. The permeability ranges from 0.02 mD in the lower sandstone (JcFirst_SS) to 0.52 mD in the lower limestone (JcFirst_LS) above their contact. The very low permeability in the lower Carmel makes it a good seal. Regardless of the low permeability in the lower Carmel Formation, there is sufficient recharge to flow down into the Navajo Sandstone. The hydraulic properties of the Carmel Formation are generally unknown or are estimated because of the lack of flow tests or tested outcrop samples.

Fracturing

Fracturing is also observed in most of the Carmel Formation outcrops on the west side of the San Rafael Swell. Many fractures are filled with calcite, gypsum, or silica cement similar to those in the Navajo Sandstone. Hood and Peterson (1984) suggest that the calcite filling the fractures in the Navajo is probably sourced from the Carmel limestone and gypsum. The majority of the water from the springs and wells in the Carmel outcrops have moderate to high TDS (see chapter 7). The Carmel Formation is likely a significant source of calcium and sodium found in fluids in the sandstone of the Carmel and other formations in the region.

WATER INJECTION WELLS

The Ferron Sandstone of the Mancos Shale produces methane gas from coal beds within the Ferron. The produced water is disposed of into numerous injection wells into the Navajo Sandstone (table 8-1). The produced water from the Ferron Sandstone is less than 10,000 TDS and therefore qualifies the Navajo Sandstone in that area as a Underground Source of Drinking Water or a USDW aquifer.

Seven produced water injections wells are currently operating at Buzzards Bench gas field. All are screened through the entire Navajo Sandstone and several are also screened in the underlying Kayenta Formation and Wingate Sandstone. Table 8-1 shows the average monthly injection rates and cumulative injection amounts (in barrels of water). Injection wells SWD No. 3 and SWD No. 1 became operational in 1996; SWD No. 2 became operational in 1998; and Clawson Spring ST SWD No. 1, SWD No. 4, PPCO D13, and SWD No. 5 became operational in 2001, 2002, 2003 and 2010, respectively. Figure 8-3 is a plot showing the average monthly injection rate for all seven injection wells along with the cumulative injected water. The average injection rate of the seven wells is 66,316 barrels per month with a high of 589,576 barrels in August 2002. Almost 94 million barrels of water have been injected into the Navajo Sandstone and secondarily into the Kayenta Formation and Wingate Sandstone.

Montgomery Watson (1997) investigated the impact of injecting large volumes of produced water into the Navajo Sandstone at wells SWD No. 1 and SWD No. 2 (table 8-1). Their study used THWELLS™ (IGWMC™) to calculate the potentiometric head during injection modeling at two different rates: 100 gallons per minute (gpm) and 500 gpm for 5-, 10-, and 30-year periods. With the projected injection rate of 100 gpm for 30 years, the maximum hydraulic head was calculated at 6360 feet with a tight mound of water 6 miles in diameter. At a higher injection rate of 500 gpm for 30 years, the hydraulic head was calculated to be 10,390 feet with a broader water cone 8 miles in diameter. The modeling shows that the Navajo can accommodate large volumes of water with very negligible impact. It has been 20 years since injection started and additional research could see if the modeling predicted the actual hydraulic head and water mounding.

SUMMARY

The regional hydrogeology of the western San Rafael Swell has been studied by several different investigators in the last 50 years. Multiple aquifers and aquitards are identified and are locally good sources of water. The Entrada Sandstone and Dakota Formation are two potential aquifers in the region near the Huntington Power Plant. However, they do not have enough hydrostatic pressure in the Hunter and Drunkards Wash study sites to keep the CO_2 in the liquid state. The Glen Canyon Group consisting of the Wingate Sandstone, Kayenta Formation, and Navajo Sandstone has the most regionally extensive aquifer system on the western side of the San Rafael Swell. The Kayenta and Wingate have limited thickness, less than 600 feet combined, and their hydrogeologic parameters are not well known. There are several active injection wells at Buzzards Bench (see figure 8-1) that are perforated through the entire thickness of the Glen Canyon Group. The combined units were tested as one continuous unit so individual parameters are unknown. The lithology of the Kayenta and Wingate suggests that the porosity and permeability will be significantly lower than the Navajo. The Carmel Formation has great aerial outcrop exposure and has locally perched aquifers that make springs and wells. Thick gypsum and anhydrite are found in the Carmel on the western side of the San Rafael Swell which make barriers to fluid flow.

Several samples were collected from the eolian sandstone facies of the Navajo Sandstone and the base of the Carmel Formation. The Navajo porosities ranged from 7.9% in the interdune sample to 18.7% in the wind ripple sample. It should be noted that these numbers are in general agreement with those presented by Hood and Patterson (1984). Measured permeability varies widely from 17.7 mD in the interdune to 1375 mD in the wind ripple. Carmel porosity except in the gypsum and anhydrite units can be considered low to moderate with vertical porosity ranging from 5% to 16.1%; horizontal porosity ranged from 8.4% to 13.9%. Measured permeability ranged from 0.02 to 0.52 mD. Vertical fluid flow between the Carmel and Navajo is suggested by the relatively high TDS of water in the Navajo sandstone as well as by calcite fracture fill observed in outcrop and core.

Hood and Patterson (1984) presented hydraulic parameters for the Navajo Sandstone from several, short-term aquifer tests on wells completed in the sandstone. Hydraulic conductivity ranged from 0.0037 ft/d to 5.1 ft/d. Transmissivities ranged from 23 ft^2/day to 643 ft^2/day. Specific yield ranged between 5% and 10%. The different eolian facies and fracturing can widely impact fluid flow in the Navajo. Stim-Lab (1997) indicates the short length fracturing is part of the overall permeability and that the reservoir is likely underpressured. The hydrologic properties of the Carmel Formation have not been measured on outcrop samples or by flow testing in the study areas and must be estimated from previous regional studies.

Seven produced water injection wells are active in the Buzzards Bench gas field west of the Huntington Power Plant. Several have been in operation since 1996 with the last coming online in 2010. Average injection is 66,316 barrels of water with a high of 589,576 barrels. A total of 93,584,842 barrels have been injected into the Navajo Sandstone since the operation started in 1996. Montomery Watson (1997) modeled the water injection into two closely spaced injection wells, the SWD No. 1 and SWD No. 2, at 100 and 500 gpm injection rates for 5, 10, and 30 years. The predicted hydraulic head for the 100 gpm and 500 gpm rates varied from 6360 feet to 10,390 feet with a tight water mound diameter of 6 to 8 miles. The modeling predicted a very small impact to the potentiometric surface in the Navajo Sandstone after 30 years of injection.

CHAPTER 8 FIGURE AND TABLE CAPTIONS

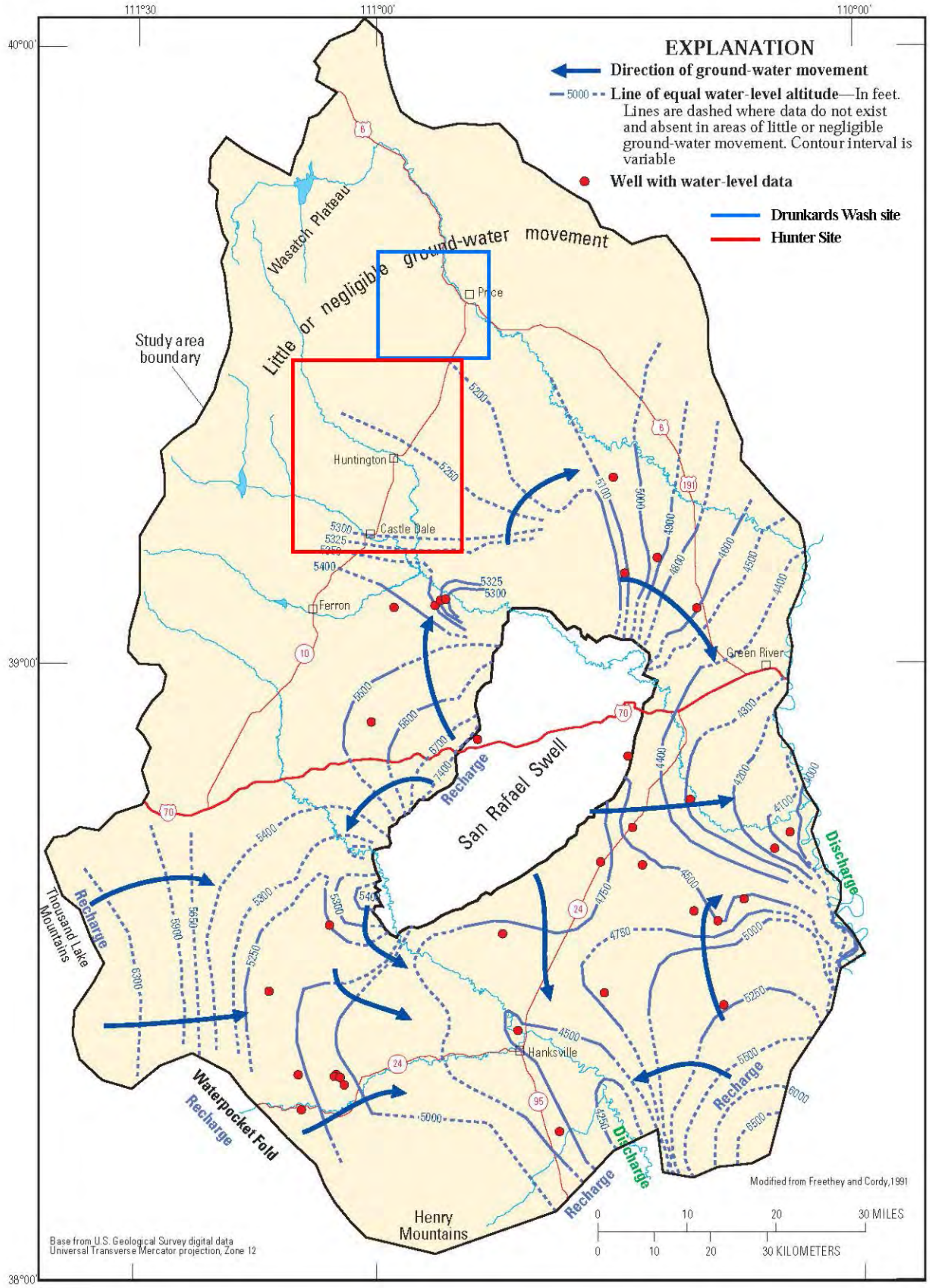
Figure 8-1. Map showing the Navajo Sandstone and Carmel Formation recharge areas surrounding the San Rafael Swell. Groundwater recharge splits south of the Hunter study site.

Groundwater in the Navajo flows northwest towards Price and then bends to the east and southeast to the lower Green River discharge area. Modified from Freethey and Stolp (2009).

Figure 8-2. Map showing the Huntington and Drunkards Wash study areas and the location of the outcrop samples collected from the Navajo Sandstone and lower Carmel Formation. Red dots indicate approximate locations of sample sites; Jn = Jurassic Navajo samples, Jc = Jurassic Carmel samples, LW = Little Wedge fault area.

Figure 8-3. Average monthly injection and cumulative injection of produced water (in barrels) amount into the seven injection wells at Buzzard Bench field and listed in table 8-1.

Table 8-1. List of injection wells and produced water injected (bbls) at Buzzards Bench field which is within the preferred Hunter study site.



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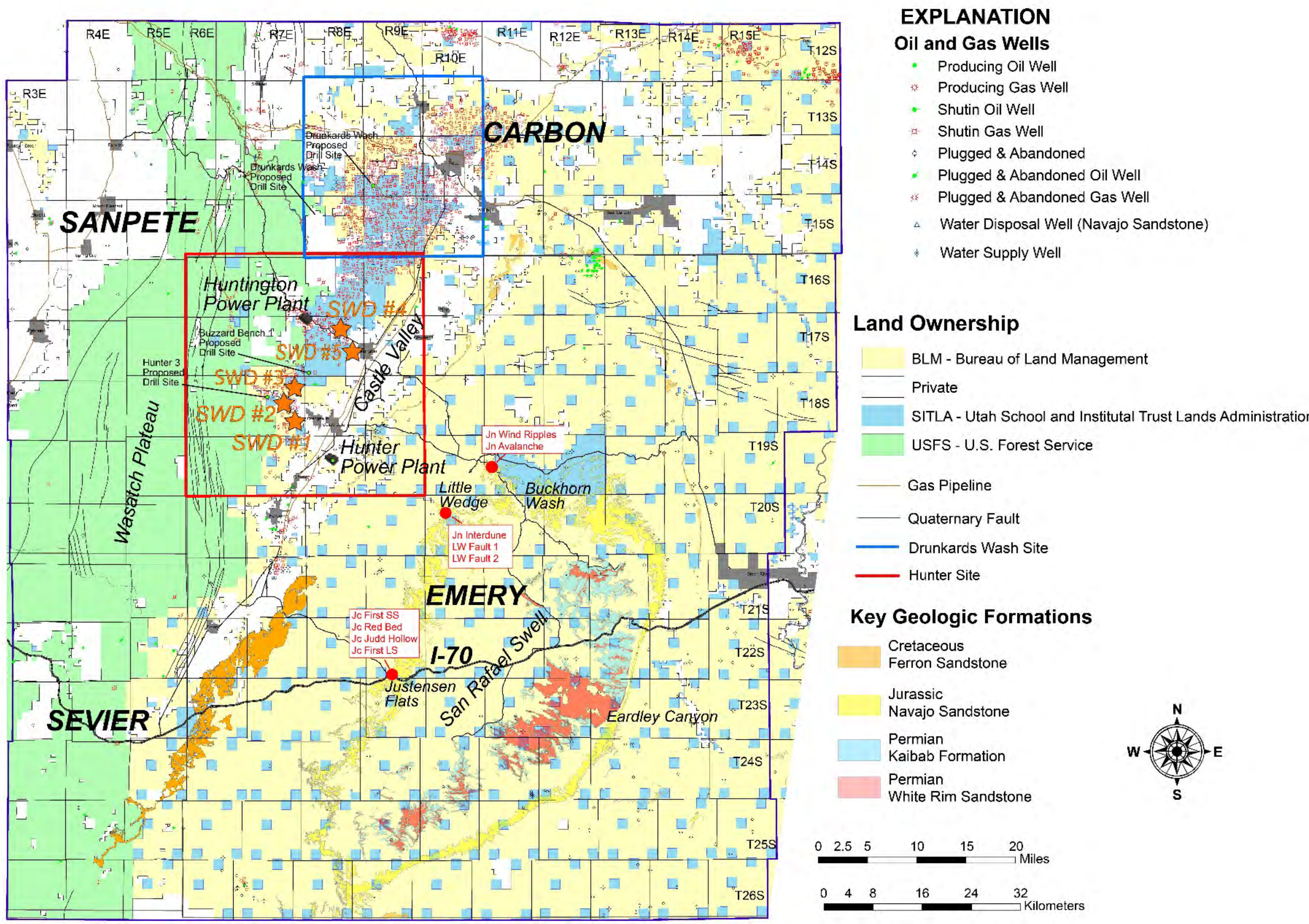

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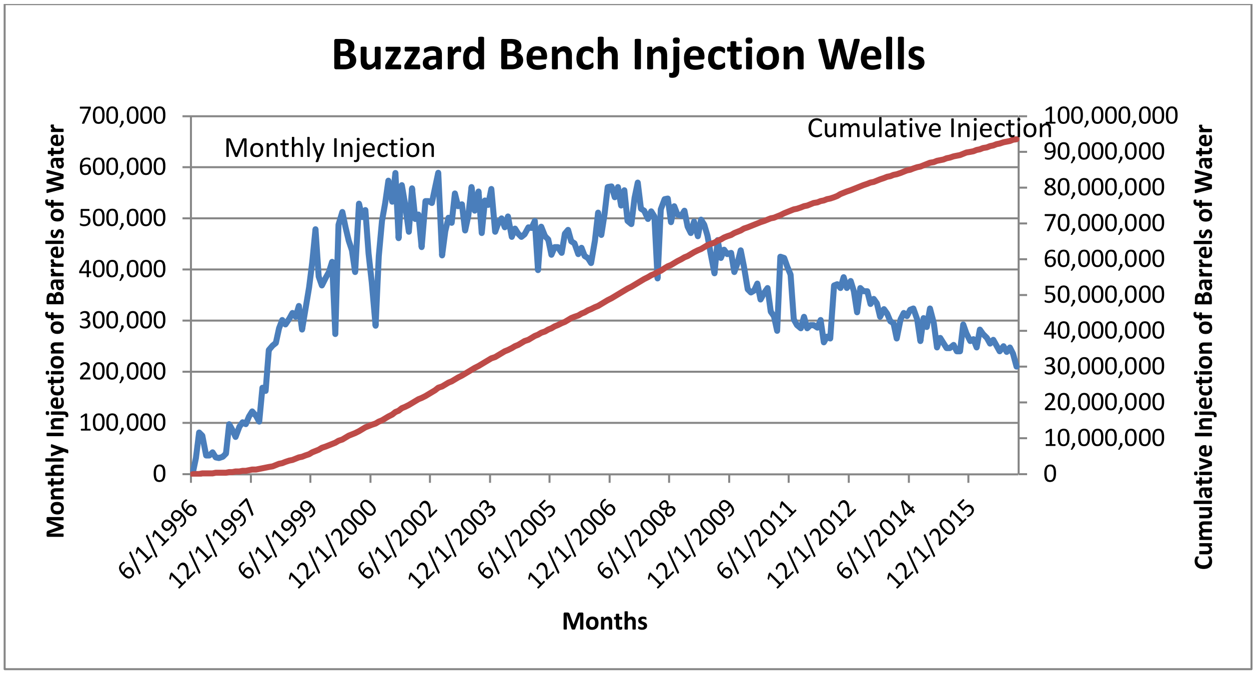

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Table 8-1. List of injection wells and produced water injected (bbls) at Buzzards Bench field which is within the preferred Hunter study site.

Injection Well	Operation Date	Operational Months	Average Injection Rate (bbls/month)	Cumulative Injection Amount (bbls)
SWD No. 1	1996	248	145,957	36,197,231
SWD No. 2	1998	227	117,172	26,598,120
SWD No. 3	1996	176	72,453	7,897,371
SWD No. 4	2002	179	62,097	11,115,390
SWD No. 5	2010	160	25,592	4,094,775
Clawson Spring St SWD 1	2001	192	32,834	6,304,091
PPCO D13	2003	170	8105	1,377,864
TOTAL			**66,316**	**93,584,842**

Rocky Mountain CarbonSAFE Phase I

Appendix I

POTENTIAL FOR SEISMIC ACTIVITY

POTENTIAL FOR SEISMIC ACTIVITY

Emily Kleber and Gordon Douglass,
Utah Geological Survey

INTRODUCTION

The western flank of the San Rafael Swell is on the northwestern boundary of the Colorado Plateau. The western boundary of the Colorado Plateau is a region of increased seismicity called the Intermountain Seismic Belt (ISB). ISB seismicity is associated with tectonic extension in the Basin and Range physiographic province to the west. Seismicity is relatively low on the Colorado Plateau, with the exception of seismicity concentrated in a transition zone between extension of the Basin and Range province and the thick continental crust of the Colorado Plateau (figure 9-1). A few notable earthquakes could have been felt within the Hunter and Drunkards Wash study areas west-northwest of the San Rafael Swell (figure 1-2).

QUATERNARY-ACTIVE FAULTS

There are no mapped Quaternary-active faults within the San Rafael Swell or on its western axis according to the Utah Quaternary Fault and Fold Database (2018). Non-Quaternary faults in the San Rafael Swell include the northwest-southeast Paradox Basin and Uncompahgre uplift trend, an east-west trend, and north-south Basin and Range extensional trend.

The closest Quaternary-active faults to the study sites in the Castle Valley area are those in the southern extent of the Joes Valley fault zone (~30 km to the west) and the Price River area faults (~30 km to the northeast) (figure 9-2). The Joes Valley fault zone is a normal-fault-bounded graben with north-south-trending, locally overlapping fault traces, and is divided into southern and northern segments. The southern segment, which is closest to the study areas, is thought to be less active than the northern segment due to a decrease in fault throw and relatively few scarps cutting Quaternary deposits (Black and others, 2006). The Price River area faults are thought to be related to the salt-cored anticlines associated with the Paradox Basin (Hecker, 1993).

SEISMICITY

Historical Seismicity

Historical seismicity has occurred on the western flank of the San Rafael Swell, including the 1988 M_L 5.3 San Rafael Swell earthquake. At 13:03 MST on August 14, 1988, a local magnitude (M_L) 5.3 earthquake occurred that had an epicenter proximal to the study sites (Pechmann and others, 2011). The earthquake had a Modified Mercalli Intensity (MMI) magnitude of VI with a felt area of ~110,000 square kilometers over areas of Utah and Colorado. The earthquake epicenter was about 18 km northwest of Castle Dale, Utah (figure 9-2).

Hypocenters of the mainshock and aftershock sequence occurred at 11 to 18 km depth in a 5-km-long zone having a dip of 60° ± 5° east-southeast. The depth of the earthquake sequence is deeper than typical ISB or Basin and Range earthquakes. Earthquakes associated with this sequence showed left-lateral oblique-normal faulting down to the east-southeast. The earthquake occurred outside of any known areas of historical seismicity, such as the ISB or transition zone (figure 9-1). The San Rafael earthquake has no surface fault associated with its location (Pechmann and others, 1992). The earthquake shaking triggered numerous rockfalls (figure 9-3) occurring within 40 km of the epicenter during the main shock (Case, 1988). In addition to numerous accounts of seismically triggered rockfalls, field investigation at Fuller Bottom along the San Rafael River noted cracking due to liquefaction and sand boils in saturated sediments 1.9 km from the epicenter (Case, 1988).

Induced Seismicity

North and east of the study sites is a region of induced seismicity associated with coal seam exploration and extraction in the Wasatch Plateau and Book Cliffs mining districts (figure 9-1). These earthquakes are typically small (magnitude ≤ 4.2) and result from coal mining down to ~0.75 km depth. The seismicity of coal mining earthquakes in Utah are characterized by the University of Utah Seismograph Stations (http://quake.utah.edu/) and have been studied previously in detail to conduct earthquake research and address mine safety (Arabasz and Pechmann, 2001).

SUMMARY

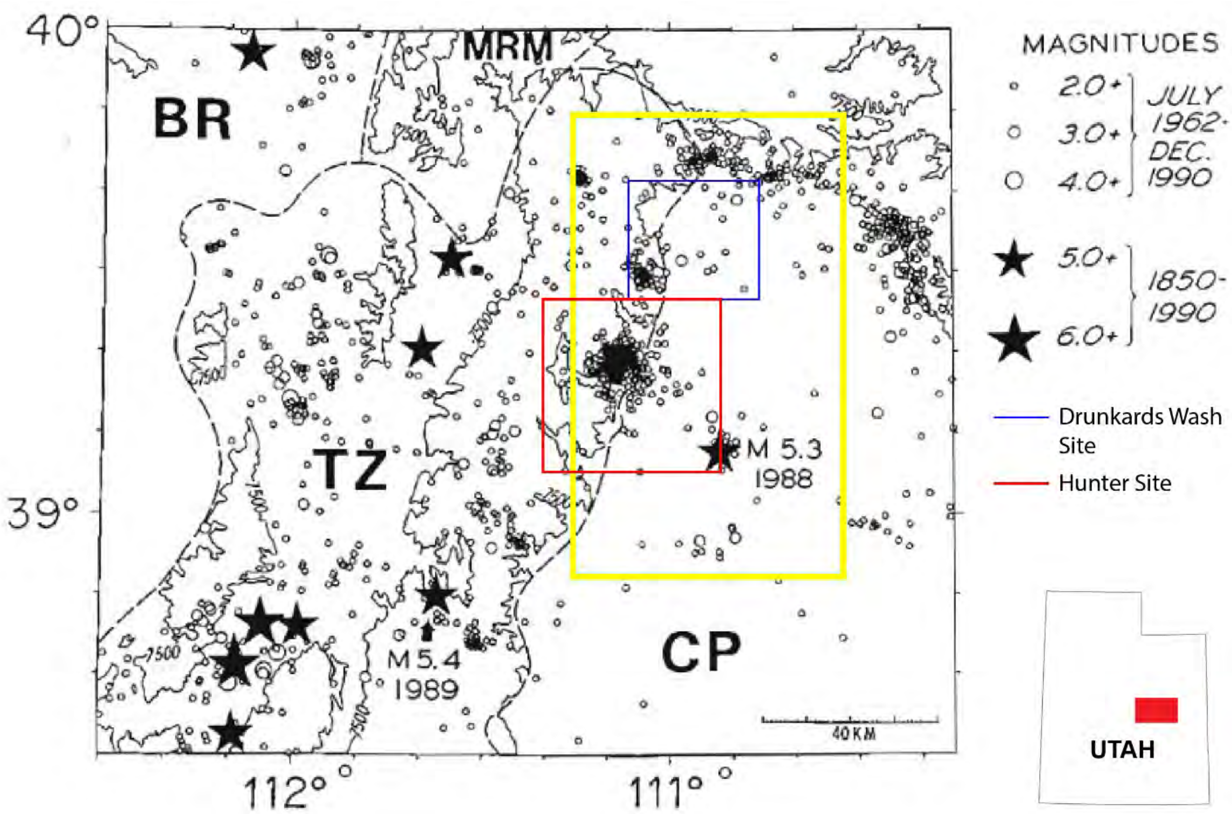
Seismicity is relatively low in the Colorado Plateau, with the exception of seismicity concentrated in a transition zone from the Basin and Range physiographic province west of the study sites in Castle Valley. There are no mapped Quaternary-active faults within the San Rafael Swell or in Castle Valley. A few notable earthquakes have occurred in the region. Although historical seismicity has occurred on the western flank of the San Rafael Swell, including the 1988 M_L 5.3 San Rafael Swell earthquake, we conclude that the potential for significant seismic activity in and around the study areas is low. A region of induced seismicity associated with coal mining in the Wasatch Plateau and Book Cliffs is north and east of the study sites and would not affect CCS in the study sites.

CHAPTER 9 FIGURE CAPTIONS

Figure 9-1. Historical regional earthquake epicenters in the San Rafael Swell area from 1962 – 1990, including the 1988 M 5.3 San Rafael Swell earthquake and the 1989 M 5.4 Wasatch Plateau earthquake. Earthquakes typical of the Basin and Range (BR) and Colorado Plateau (CP) have different seismicity that shifts in the transition zone (TZ). The Middle Rocky Mountains (MRM) is at the northern boundary of the CP. Yellow box indicates approximate area covered in figure 9-2. Modified from Pechmann (1988).

Figure 9-2. Regional Quaternary faults, historical earthquakes, and mining induced earthquakes in the study areas. The cluster of larger earthquakes and aftershocks near the center of the image is the 1988 San Rafael Swell earthquake sequence. Data sources: Quaternary faults from the Utah Geological Survey; epicenters from the University of Utah seismograph stations.

Figure 9-3. Rockfall dust associated with the 1988 San Rafael Swell earthquake taken from the Bureau of Land Management (BLM) Cedar Mountain picnic area, 18 km from the epicenter. The mainshock caused numerous rockfalls that occurred within 40 km of the epicenter. Photo taken by Terry Humphrey of the BLM Price office (1988) and accessed from the Utah Geological Survey Geodata Archive System (2018).



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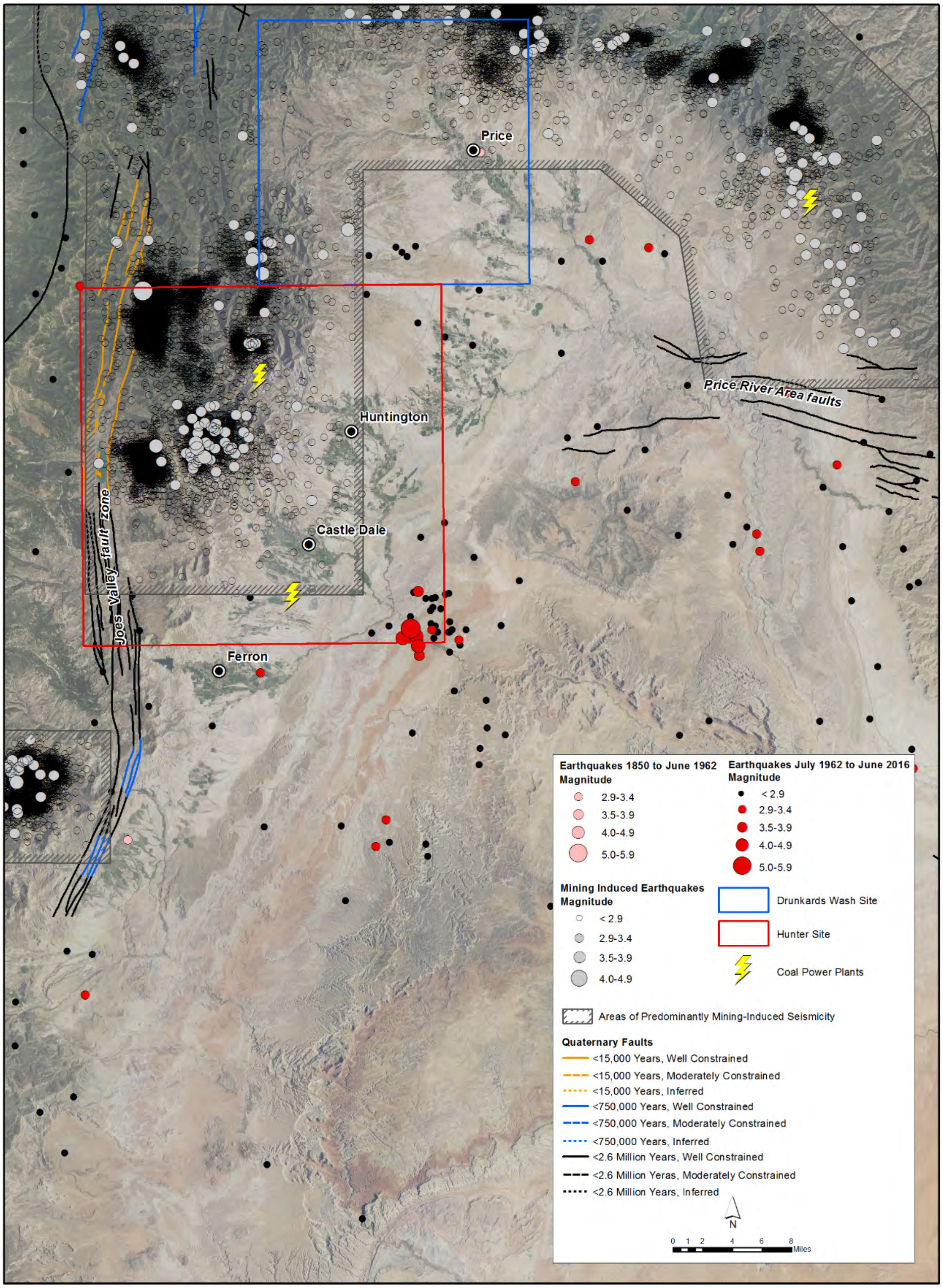

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Rocky Mountain CarbonSAFE Phase I

Appendix J

Risk Registry

QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA)				
CarbonSAFE Rocky Mountains Phase I, CO2-Storage Subsurface, Surface, Technical and Programmatic Risk Areas				
Line #	**Index #**	**Risk Area/FEP**	**Description**	**Relevance**
1	**00.00.00.00.**	**ASSESSMENT BASIS**	This category of FEPs determines the boundary conditions for any assessment, specifying the spatial and temporal domain of the system. The Assessment Basis determines what is being assessed and why, so that those FEPs that need to be considered in the analysis can be defined, and those which can be screened out as being outside the scope of the assessment can be identified.	
2	**00.01.00.00.**	Purpose of the assessment	The purpose of the assessment of geological CO2 sequestration.	The general purpose of an assessment of geological CO2 sequestration is to determine the performance of the sequestration system. In any specific case, however, the purpose of conducting an assessment may vary from simple calculations to test initial ideas for sequestration concepts, to support for an application for regulatory approval requiring detailed, site-specific performance assessment against relevant criteria. The level of complexity and comprehensiveness will vary according to the use to which it will be put. Additionally, the assessment endpoints of interest may not only vary in type, depending on the assessment purpose, but also in the level of rigor required for compliance demonstration.
3	**00.02.00.00.**	Endpoints of interest	The assessment endpoints of interest.	The structure and composition of an assessment will tend to reflect the endpoints that are required to be assessed. These in turn, will reflect the criteria that are adopted to judge the overall performance of the sequestration system. Thus, for example, an assessment may be constrained to considering the degree of containment within a geological feature, alternatively, it may need to address potential near-surface impacts. Invariably, a combination of endpoints will be required.
4	**00.03.00.00.**	Spatial domain of interest	The spatial domain of interest in the assessment.	The spatial domain of interest will be dependent on the site context, which may vary from generic assessments to site specific assessments, the sequestration concept and the endpoints of interest. The spatial domain will contribute to determining the information requirements and modeling capabilities that may be required.
5	**00.04.00.00.**	Timescales of interest	Timescale of interest for the assessment.	Timescales over which the assessment will be performed will constrain processes which must be considered in the assessment. In general terms, there are three timescales of interest for geological storage of carbon dioxide. Firstly, there is the timescale during construction and operation which has a lifetime in years or decades. secondly there is a timescale over which isolation of carbon dioxide from the atmosphere is necessary to mitigate climate change. This timescale is likely to be in the order of a few hundred years at most. The third timescale of interest is potentially much longer and is that pertaining to the assessment of potential hazard to humans and the environment. This timescale could be in the order of thousands to tens of thousands of years.
6	**00.05.00.00.**	Sequestration assumptions	High level assumptions concerning the sequestration system(s) of relevance to the assessment. For example, the quantity and quality of CO2 sequestered, the method of injection and information concerning the assumed performance of the sequestration system.	Provides a background to the sequestration technique adopted. Note that more detailed consideration of the CO2 sequestration system is provided in subsequent FEP categories.

QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA)				
CarbonSAFE Rocky Mountains Phase I, CO2-Storage Subsurface, Surface, Technical and Programmatic Risk Areas				
Line #	**Index #**	**Risk Area/FEP**	**Description**	**Relevance**
7	**00.06.00.00.**	Future human action assumptions	The assumptions made in the assessment concerning general boundary conditions for assessing future human action and exposure.	For example, it can be expected that human technology and society will develop over the timescales of relevance for the assessment of CO2 sequestration systems, however, this development is unpredictable. Therefore it may be necessary to make some assumptions in order to constrain the range of future human actions that are considered, such as assuming that only present-day technologies, or technologies practiced in the past, will be considered.
8	**00.07.00.00.**	Legal and regulatory framework	The legal and regulatory framework within which the assessment takes place.	In undertaking an assessment it is vital to consider the appropriate regulatory framework requirements. At one extreme these may be specific, prescriptive quantitative requirements, at the other they could be non-prescriptive or may not have been fully developed. The legal and regulatory framework can shape various aspects of an assessment, such as the required assessment endpoints, timescales of interest and assumptions concerning future human actions.
9	**00.08.00.00.**	Model and data issues	General methodological issues affecting the assessment modeling process and use of data	Examples of general model and data issues include the treatment of uncertainty; the availability, collection and method for handling site specific data; and the reduction/simplification of models and data.
10	**00.09.00.00.**	Public acceptance and information	The amount and type of information needed for public acceptance and to comply with industry best management practices.	Focus on health, safety and environmental risks as well as economic and lifestyle impact on the public at large.
11	**00.10.00.00**	Financial viability	The minimum return on investment needed to justify the risks involved in undertaking the project.	Higher risks require higher rewards to justify undertaking a project. The risk assessment may give an indication of the minimum rate of return required to attract capital funding for the project.
12	**00.11.00.00**	Adequate risk characterization	The level of detail and depth of risk characterization needed.	Characterization of risks can include identifying potential modes of failure, estimating probability of failure occurring and impact severity of failure and determining potential steps to prevent or mitigate failure.
13	**01.00.00.00.**	**EXTERNAL FACTORS**	This category of FEPs describes natural or human factors that are outside the system domain. These FEPs are most important in determining scenarios for the future evolution of the system, and are often referred to as EFEPs (External FEPs). Three classes of FEPs are considered. Geological Factors and Climatic Factors are concerned with natural processes and events, whilst Future Human Actions is concerned with those human activities that can directly affect the sequestration system.	This category is divided into three classes: 1. Geological factors 2. Climate factors 3. Human action factors
14	**01.01.00.00.**	Geological factors	Natural geological processes and events in the environment outside the system domain that are relevant to the evolution of the sequestration system.	Changes in the geological environment outside the system domain may directly affect the transport of carbon dioxide within the system.
15	**01.01.01.00.**	Neotectonics	Neotectonics is the study of crustal movements that both occurred in the Earths recent past and are continuing at the present day. These movements, which are driven directly or indirectly by global plate motions (tectonics), result in the vertical and horizontal warping, folding or faulting of the Earths surface.	Neotectonic events have the potential to cause sudden changes in the physical properties of rocks due to stress changes and induced hydrogeological changes.
16	**01.01.02.00.**	Volcanic and magmatic activity	Magma is molten, mobile rock material, generated below and within the Earth's crust, which gives rise to igneous rocks when solidified. A volcano is a vent or fissure in the Earth's surface through which molten or part-molten materials (lava) may flow, and ash and hot gases be expelled.	The high temperatures associated with volcanic and magmatic activity may result in permanent changes in the surrounding rocks, either directly, or through circulating high temperature fluids. This FEP is relevant to CO2 disposal in areas of potential magmatic activity, e.g. Japan. Besides bedrock damage, pressure and temperature changes due to heating, stress, or displacement could affect CO2 density and solubility , creating the risk of uncontrolled, rapid migration and escape of stored CO2. CO2STORE page 69)

QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA)				
CarbonSAFE Rocky Mountains Phase I, CO2-Storage Subsurface, Surface, Technical and Programmatic Risk Areas				
Line #	**Index #**	**Risk Area/FEP**	**Description**	**Relevance**
17	**01.01.03.00.**	Seismicity (Natural earthquakes)	Events and processes related to naturally occurring seismic events and also the potential for seismic events. A seismic event is caused by rapid relative movements within the Earth's crust usually along existing faults. The accompanying release of energy may result in rock movement and/or rupture, e.g. earthquakes. Many people are convinced that we want to avoid seismically-active areas for CO2 storage. In reality there are very large natural gas fields associated with some of the planet's major fault zones (Indonesia, Malaysia and California). Earthquakes in these areas have never been associated with sudden emissions of significant quantities of natural gas or oil from deep reservoirs. (CCP 2009) Major earthquakes (magnitude 6 and above) occur primarily in strong, brittle basement rock at depths on the order of 10 km (6 miles) or more. Very small earthquakes occur at depths as shallow as 3 km (2 miles). Micro-seismicity consists of very tiny seismic events often responding to subsurface fluid flow and relative pressure changes. All parts of the Earth's crust are in continuous movement and generate micro-seismic events, and the analysis of micro-seismicity offers unique insights into subsurface properties(CCP 2009). 1. Earthquake induced fractures/faults 2. Natural micro-seismicity	Seismic events may result in changes in the physical properties of rocks due to stress changes and induced hydrogeological changes. Seismic events are most common in tectonically active or volcanically active regions at crustal plate margins. Seismic disturbances might cause caprock failure (Damen 2006). Earthquakes could disrupt drilling, well operation, and monitoring activities, and damage surface facilities including the CO2 source. An earthquake on a fault through the CO2 plume could create or close an open pathway. Earthquakes may cause public concern about the project even if not project related. Micro-seismicity may cause public concern about the project even if not project related, may add noise interfering with micro-seismic monitoring. Earthquake near Nakaoka, Japan CO2 injection site caused significant public concern causing project to be moved off shore, even though earthquake was not directly caused by CO2 injection.
18	**01.01.04.00.**	Hydrothermal activity	Processes associated with high temperature groundwaters, and hydrothermal alteration of minerals in the rocks through which the high temperature groundwater flows. Hydrothermal activity may be directly associated with volcanic and magmatic activity. Hot springs, geysers and submarine hydrothermal vents provide evidence of hydrothermal activity.	Can result in the hydrothermal alteration of rocks or minerals by the reaction of hot water (and other fluids) with pre-existing rocks. Springs, geysers and submarine hydrothermal vents can provide pathways for CO2 to reach the surface.
19	**01.01.05.00.**	Hydrological and hydrogeological response to geological changes	Processes arising from large-scale geological changes and could include changes of fluid boundary conditions due to the effects of changes of fluid properties of geological units due to changes in rock stress or fault movements.	In and below low-permeability geological formations, hydrogeological conditions may evolve very slowly and often reflect past geological conditions, i.e. be in a state of disequilibrium
20	**01.01.06.00.**	Large scale erosion **(See 06.01.03.00)**	Processes related to the large scale (geological) removal of rocks and sediments, with associated changes in topography and geological/hydrogeological conditions of the system.	Potential to modify the geological and hydrogeological environment.
21	**01.01.07.00.**	Bolide impact (meteorite impact)	An extraterrestrial body in the 1-10 km size range, which impacts the earth at high velocity, explodes upon impact, and creates a large crater.	A low probability, high consequence event that has the potential to substantially disrupt the CO2 storage system. Often screened out on the basis that the impact of the bolide will greatly exceed that of the disruption caused to the sequestration system.

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22	**01.02.00.00.**	Climatic factors	Natural processes and events in the atmospheric environment that are relevant to the evolution of the sequestration system.	Changes in climate may directly affect the nature of any impacts that are incurred if carbon dioxide returns to the near-surface environment.
23	**01.02.01.00.**	Global climate change **(See 01.02.02.00.)**	The process of global climate change due to natural and/or anthropogenic causes. The last two million years of the Quaternary have been characterized by glacial/interglacial cycling. According to the Milankovitch Theory, the Quaternary glacial/interglacial cycles are caused by long-term changes in seasonal and latitudinal distribution of incoming solar radiation which are due to the periodic variations of the Earth's orbit about the Sun (Milankovitch cycles). Evidence suggests that the Earth is presently in a period of global warming. The anthropogenic release of gases into the atmosphere may be increasing the rate of global warming by enhancing the natural greenhouse effect, a process by which long wave radiation emitted from the Earth is trapped in the atmosphere by greenhouse gases	Changes in the global climate are likely to impact the CO2 sequestration system in a number of ways. For example, through its affect on sea levels and the local and regional climate. Changes in ecology and human behavior in response to climate change will influence the relevant FEPs to be considered in the surface environment as an assessment extends into the future. Changes in air emission policies in response to global climate change will impact the feasibility of using CCS.
24	**01.02.02.00.**	Regional and local climate change (extreme weather events damaging facilities)	Processes related to the possible future changes, and evidence for past changes, of climate at a storage site. This is likely to occur in response to global climate change, but the changes will be specific to situation, and may include short term fluctuations. Climate is characterized by a range of factors including temperature, precipitation and pressure as well as other components of the climate system such as oceans, ice and snow, biota and the land surface. Climatic changes lasting only a few decades may be referred to as climatic fluctuations. These are unpredictable at the current state of knowledge although historical evidence indicates the degree of past fluctuations. 1. Warm climate effects **(01.02.06.00)** 2. Cold climate effects 3. Wet climate effects 4. Dry climate effects 5. Hydrological and hydrogeological response to climate change **(01.02.07.00)**	Changes in the regional and local climate could affect the CO2 sequestration system in a number of ways. For example, changes in groundwater recharge could affect regional hydrogeology and hence the transport of CO2 dissolved in groundwater. It may also alter the near-surface environment to which some of the disposed CO2 may migrate. Regions with a tropical climate may experience extreme weather patterns (monsoons, hurricanes) that could result in flooding, storm surges, high winds etc. with implications for erosion and hydrogeology. The high temperatures and humidity associated with tropical climates result in rapid biological degradation and soils are generally thin. In arid climates, total rainfall, erosion and recharge may be dominated by infrequent storm events. The hydrology and hydrogeology of a region is closely coupled to climate. Climate controls the amount of precipitation and evaporation, seasonal ice cover, and thus the soil water balance, extent of soil saturation, surface runoff groundwater recharge, sediment load and seasonality. Vegetation and human actions may modify these responses.
25	**01.02.02.01.**	Extreme weather event causing human injury/death	Extreme weather events such as tornadoes or hurricanes may cause human injury/death.	Site may not provide sufficient protection for opertors against extreme weather events such as tornadoes
26	**01.02.03.00.**	Sea level change	Processes related to changes in sea level which may occur as a result of global (eustatic) change and/or regional geological change, e.g. isostatic movements. The component of sea-level change involving the interchange of water between land ice and the sea is referred to as eustatic change. As ice sheets melt so the ocean volume increases and sea levels rise. Sea level at a given location will also be affected by vertical movement of the land mass, e.g. depression and rebound due to glacial loading and unloading, referred to as isostatic change.	Sea level change may affect the sequestration system through its impact on the near surface environment and the regional or local hydrogeological regime.

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27	**01.02.04.00.**	Periglacial effects	Related to the physical processes and associated landforms in cold but ice-sheet-free environments.	An important characteristic of periglacial environments is the seasonal change from winter freezing to summer thaw with large water movements and potential for erosion. Frozen sub-soils are referred to as permafrost. Melt water from seasonal thaw is unable to percolate downwards due to permafrost and saturates the surface materials. Permafrost layers may isolate the deep hydrogeological regime from surface hydrology, or flow may be focused at "taliks" (localized unfrozen zones, e.g. under lakes, large rivers or at regions of groundwater discharge).
28	**01.02.05.00.**	Glacial and ice sheet effects	Processes related to the effects of glaciers and ice sheets within the region of a storage site. This is distinct from the effects of large ice masses on global and regional climate. The ice sheet and the permafrost beneath the ice sheet may constitute a barrier to groundwater flow and to heat loss. If the basal transmissivity of the till and bedrock below the ice is low, water pressures may rise to levels equaling the ice pressure inducing the formation of major conduits in the subglacial material. The central parts of the ice sheet are likely to be warm-based and could permit groundwater recharge to take place. Discharge of groundwater is likely to take place close to and beyond the frontal parts of the ice sheet. Excessive recharge at the margin of the ice sheet could provide direct recharge of oxidizing water to considerable depths in conductive fracture zones. If the permeability at and beyond the rim of the ice is low, the water pressures may again build up resulting in hydrofracturing of the ice or the rock mass. As the ice sheet advances, these induced fractures may increase their aperture and depth due to freezing of subglacial melt water.	Erosional processes (abrasion, over deepening) associated with glacial action, especially advancing glaciers and ice sheets, and with glacial melt waters beneath the ice mass and at the margins, can lead to morphological changes in the environment, e.g. U-shaped valleys, hanging valleys, fjords and drumlins. Depositional features associated with glaciers and ice sheets include moraines and eskers. The pressure of the ice mass on the landscape may result in significant hydrogeological effects and even depression of the regional crustal plate.
29	**01.02.06.00.**	Warm climate effects (**See 01.02.01.00.)**		
30	**01.02.07.00.**	Hydrological and hydrogeological response to climate changes (**See 01.02.01.00.)**		
31	**01.02.08.00.**	Responses to climate change (**See 01.02.01.00.)**		
32	**01.03.00.00.**	Future human actions	Human activities that are relevant to the evolution of the sequestration system.	Human activities may directly interfere with the sequestered fluid resulting in immediate or delayed impacts.
33	**01.03.01.00.**	Human influence on climate (**See 01.02.01.00.)**		
34	**01.03.02.00.**	Motivation and knowledge issues (Future interference with or intrusion into the CO2 reservoir by third parties)	Events and processes related to the degree of knowledge of the existence, location and/or nature of the storage site. Also, reasons for deliberate interference with, or intrusion into, a CO2 storage site after closure with complete or incomplete knowledge. Knowledge of the sequestration site may be regained through post-closure airborne, geophysical or other surface-based non-intrusive investigation of a sequestration site. Such investigations might occur after information of the location of the sequestration system has been lost and therefore excludes monitoring of the disposal system, but includes activities such as prospecting for geological resources. The evidence of the sequestration, such as injection boreholes, may itself prompt investigation. 1. Inadvertent interference with or intrusion into the CO2 reservoir. 2. Deliberate interference with or intrusion into the CO2 reservoir. 3. Malicious intrusion and sabotage.	Some future human actions could directly impact upon performance of the storage system. The following could be distinguished: - inadvertent actions, which are actions taken without knowledge or awareness of the storage site, and - deliberate actions, which are actions that are taken with knowledge of the storage systems existence and location, e.g. deliberate attempts to retrieve any hydrocarbons (e.g., EOR and ECBM) associated with the CO2 - malicious intrusion and sabotage. Intermediate cases, of intrusion with incomplete knowledge, could also occur. Terrorist activities against pipelines and facilities.

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35	**01.03.03.00.**	Social and institutional developments	Events and processes related to changes in social patterns and degree of local government, planning and regulation. Potentially significant social and institutional developments include: 1. Changes in planning controls (zoning) 2. Environmental legislation; 3. Demographic change and urban development; 4. Changes in land use; 5. Loss of archives/records, loss/degradation of societal memory.	Social and institutional developments have the potential to affect motivation and knowledge issues, human use of the surface and sub-surface environments and the type of impacts that may be considered.
36	**01.03.04.00.**	Technological developments	Events and processes related to future developments in human technology and changes in the capacity and motivation to implement technologies. This may include retrograde developments, e.g. loss of capacity to implement a technology. 1. New technology replacing the need for CO2 geologic sequestration 2. New low-cost desalination making saline aquifers more valuable 3. Lack of CO2 capture technology improvements making it too expensive 4. Robotic underground mining making deeper resources	Of interest are those technologies that might change the capacity of humans to intrude deliberately or otherwise into a storage site, to cause changes that would affect the movement of CO2 and associated contaminants, or that may otherwise affect the performance and safety of the sequestration system. Technological developments are likely but may not be predictable especially at longer times into the future.
37	**01.03.05.00.**	Drilling activities (third-party drilling through caprock)	Events related to any type of drilling activity in the vicinity of the CO2 sequestration system. These may be taken with or without knowledge of the disposal and may include activities such as: 1. Exploratory and/or exploitation drilling for natural resources; 2. Attempted recovery of residual hydrocarbon resources (e.g., EOR, ECBM, shale gas); 3. Drilling for water resources; 4. Drilling for site characterization or research; 5. Drilling for liquid waste or other fluids disposal; 6. Drilling for geothermal resources.	Has the potential to disrupt geological features that provide a barrier to CO2 migration and provide a relatively quick migration pathway to the near-surface.
38	**01.03.06.00.**	Mining and other underground activities	Events related to any type of mining or excavation activity carried out in the vicinity of the storage site. These may be taken with or without knowledge of the site. Mining and other excavation activities include: 1. Resource mining or quarrying; 2. Excavation for industry, storage, disposal or military purposes; 3. Scientific or archaeological investigation; 4. Shaft construction, underground construction and tunneling; 5. Underground nuclear testing; 6. Malicious intrusion, sabotage or war;	Mining and other underground activities have the potential to disrupt the geosphere (storage reservoir, surrounding and overlying rock) and near-surface environment. They therefore have the potential to significantly affect the migration and distribution of sequestered CO2.
39	**01.03.07.00.**	Human activities in the surface environment	Events and processes related to any type of human activities that may be carried out in the surface environment that can potentially affect the performance of the storage system, or leakage pathways, excepting those FEPs related to water management which are described elsewhere. Examples include: 1. Residential, industrial, and infrastructure construction; 2. Pollution of surface environment and groundwater. 3. Change in groundwater geochemistry not caused by project. 4. Human activities in the surface environment offsite (farming, harvesting, irrigation maintenance) in low areas with limited air circulation.	Human activities in the surface environment have the potential to affect CO2 release processes, should leakage occur. They may also determine the types of impact to be considered or activities that would increase risk exposures.

Modified from Quintessa's on-line CO2 FEP database, which is freely accessible at www.quintessa.org/co2fepdb

Blue = not applicable or incredible; Yellow/Orange = Headings or non-risk areas

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40	**01.03.08.00.**	Water management	Events and processes related to groundwater and surface water management including water extraction, reservoirs, dams, and river management. Water is a valuable resource and water extraction and management schemes provide increased control over its distribution and availability through construction of dams, barrages, canals, pumping stations and pipelines. Groundwater and surface water may be extracted for human domestic use (e.g. drinking water, washing), agricultural uses (e.g. irrigation, animal consumption) and industrial uses. 1. Water extraction 2. Surface water reservoir construction 3. Dam construction	Extraction and management of water may affect the movement of CO2 or associated contaminants to and in the surface environment.
41	**01.03.09.00.**	CO2 presence influencing future operations	The presence of injected CO2 may hinder future extractive operations by obscuring seismic traces or by making the drilling process more difficult. Conversely, the presence of CO2 locally, might allow for more economic future enhanced oil recovery operations. This FEP assumes that future technical advances might identify useable resources in the vicinity of previous CO2 injection.	Drilling through a formation filled with supercritical CO2 might cause 'blowouts' or loss of CO2 along the wellbore. A CO2 'bubble' will change the velocity of seismic waves, distorting the 'image' of the underlying formations, and reducing confidence in the understanding of this structure.
42	**01.03.10.00.**	Explosions and crashes **(See 16.27.00.)**		
43	**02.00.00.00.**	**CO2 STORAGE**	This category of FEPs specifies details of the sequestration concept under consideration. It is split into two classes for the pre- and post-closure periods.	This category is divided into two classes: 1. Pre-closure 2. Post-closure
44	**02.01.00.00.**	Pre-closure	Details of the sequestration concept, the fluids injected, and factors for the design, construction, operation and decommissioning phases.	The details of the sequestration concept are fundamental to determining which FEPs in other categories need to be considered in a given assessment. Some details of sequestration operations may affect the post-closure performance.
45	**02.01.01.00.**	Storage concept	Features related to the concept of storage, such as whether a closure exists (sequestration in an abandoned oil or gas field or coal seam) or whether isolation of CO2 is dependent upon slow diffusion rates through an extensive open structure (saline aquifer sequestration). 1. Deep saline aquifer CO2 storage - Sealed reservoir - Open reservoir 2. EOR CO2 storage 3. ECBM CO2 storage 4. Temporary CO2 storage and pumping facilities - Above ground - Underground (see Reversibility)	Different processes will be relevant to different storage concepts. For example, the rate of CO2 migration in an open aquifer will be relevant to safety assessment of saline aquifer storage, but less relevant to sequestration in a closed geological structure.

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46	**02.01.02.00.**	CO2 quantities, injection rate	Features related to the amounts of CO2 injected and their rate of injection into the storage aquifer/reservoir.	High rates of CO2 injection could have adverse affects, such as formation fracturing. For fast injection rates, displacement of oil/water will not be efficient during enhanced oil recovery; instead one will recover CO2; premature breakthrough is undesirable from an economic perspective. Larger volumes of injected CO2 are likely to result in more frequent and more intense induced seismicity unless compensated for with simultaneous production of fluids.
47	**02.01.03.00.**	CO2 composition	The composition and physical state (liquid, supercritical fluid etc.) of injected CO2, with contents of impurities etc. Temperature and pressure of injected fluid are also relevant. During CO2 storage operations, the principal injected gas is CO2 captured and concentrated from human activity sources. However, the gas that is injected into a reservoir may not be 100 % CO2, especially if there is some recycling of gas (in the case of enhanced oil recovery). Impurities can include: H2S, CH4, N2, NOx, SO2 and mercaptans. These may be present either intentionally or because it could be particularly difficult or superfluous to separate them from CO2. The CO2 stream may contain such things as: corrosives, noncondensible gases, oxidants, toxic impurities, flammable/combustible/pyrophoric constituents, odorous constituents, organics or particulates.	The presence of even small amounts of other gases has a strong effect on the phase behavior of CO2-dominated gases. High-pressure equations of state for CO2-dominated gas mixtures are required to take into account changes in critical pressures and temperatures caused by the presence of other gases. Impurities will reduce the critical temperature which, in turn, has effects on interfacial tension. Impurities may affect pore water chemistry (pH and redox conditions, for example) depending on the impurities involved. Special care is needed when considering corrosive gases, such as H2S.
48	**02.01.03.01.**	CO2 containing H2S	High concentration of hydrogen sulfide (H2S) in the CO2 makes it a toxic waste which can lead to more stringent permitting and compliance requirements. It also increases the safety risks. The exposure threshold at which H2S is immediately dangerous to life or health, according to the National Institute of Occupational Safety and Health, is 100 ppm, compared to 40,000 ppm for CO2 (IPCC 2005) H2S should be kept below maximum concentration of 10 to 200 ppm in the CO2 for safety reasons.	Sufficient quantities of H2S + H2O in CO2 can cause corrosion or sulfide stress cracking (CCP 2009) and increase safety risks. H2S is strong smelling and requires additional sealing around the wellhead to capture fugitive emissions and minimize odors. On a positive side, H2S in CO2 can decrease minimum miscibility pressure (MMP) for enhanced oil recovery and makes small CO2 leaks easier to detect due to the smell.
49	**02.01.03.02.**	CO2 containing H2O	In order to prevent corrosion in pipeline and wellhead systems, CO2 is normally dehydrated to less than 0.5 g/m^3 (30 lb per MMCF) or less than 20 ppm. (WRI 2008)	If the water vapor is not removed prior to compression, the CO2 product will be very corrosive and the pipeline well head and borehole would have to be built with much more expensive materials than carbon steel.

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50	**02.01.03.03.**	CO2 containing O2	EOR and deep saline applications can tolerate some oxygen (air) in the CO2, but ECBM can't. Oxygen in CO2 will shift the boundary of the two-phase region toward higher pressures and would require a higher operating pressure to avoid two-phase flow. The preferred specification is less than 10 ppm oxygen. Oxygen in the 1-2% range or above could impact mineralogical reactions in the reservoir.	Oxygen in CO2 can cause pipeline corrosion, oxidize oil in EOR or oxidize coal and/or methane in ECBM. High oxygen content (5-10%) will not liquefy or dissolve in downhole storage of CO2, and therefore will result in undesirable back pressure and downhole gas pockets. Oxygen can contaminate or degrade CO2 capture and CO2 dehydration sorbents. Oxygen could cause subsurface microbial growth but is not expected to have a significant impact.
51	**02.01.03.04.**	CO2 containing N2	Nitrogen in CO2 will shift the boundary of the two-phase region toward higher pressures and would require a higher operating pressure to avoid two-phase flow. Nitrogen is normally kept to less than 4% of volume in CO2.	Nitrogen is undesirable for EOR because it raises the minimum miscibility pressure (MMP) of the fluid and makes the injection process less efficient. Nitrogen is not a problem in ECBM as a minor component of CO2. It will lower the partial pressure of methane and allow more methane to be released and recovered. Minor amounts of nitrogen in CO2 can increase compression and transmission energy consumption and can result in two phase operation. Nitrogen (and argon) will not liquefy or dissolve in downhole storage of CO2, and therefore will result in undesirable back pressure and downhole gas pockets.
52	**02.01.03.07.**	CO2 containing CH4 and other hydrocarbons	Total hydrocarbons are normally kept to less than 5% of volume in CO2.	Methane and other hydrocarbons can be a combustion concern in the presence of oxygen. Methane can impact the maximum miscibility pressure (MMP) of CO2 and oil in EOR.
53	**02.01.03.08.**	CO2 containing mercaptans	Mercaptans are organic compounds containing sulfur. Total sulfur in CO2 is normally kept to less than 35 mg/l. Methyl mercaptan is susceptible to photo oxidation in the atmosphere to hydrogen, sulfur dioxide, dimethyl disulfide and other polysulfide's. Therefore it has a relatively low half-life. Methyl mercaptan exhibits a toxicity similar to, but less than that of hydrogen sulfide. The OSHA permissible exposure level (PEL) is 10 mg/l.	Mercaptans and other malodorous sulfur compounds are strong smelling and toxic and require additional sealing around the wellhead to capture fugitive emissions and minimize odors. The strong odor of mercaptans suggests it is unlikely humans would willingly tolerate concentrations much above the odor threshold for any substantial period of time. However humans in occupational settings may rapidly succumb to extremely high levels of methyl mercaptan.
54	**02.01.03.09.**	CO2 containing NOx, SOx	Traces of NOx and SOx may occur when CO2 is captured from a post-combustion operations. Although sulfur is present in most fossil fuels, the amount of SOx in the CO2 stream is expected to be very low because deep sulfur removal is required prior to post-combustion CO2 capture to prevent excessive sorbent degradation/loss. Pre-combustion and post-combustion are likely to produce <0.01 vol % SOx and <0.01 vol % NOx in the CO2 stream (IPCC 2005). Oxyfuel combustion may produce 0.5 vol % SOx and 0.01 vol % NOx in the CO2 stream (IPCC 2005).	NOx and SOx may increase corrosion in pipeline and wellhead systems if H2O is present. NOx and SO2 are polluting gases that are generated by the same power plants that generate massive amounts of CO2 and attract emission taxes in certain countries (e.g. Italy). Their injection, in smaller amounts, with CO2 could therefore help the economics of sequestration. Different sets of geochemical reactions are expected when these trace contaminants are present.
55	**02.01.03.10.**	CO2 containing particulates	CO2 is normally scrubbed clean of particulates prior to input into the pipeline. Particulates could carry over due to upset conditions.	Particulate matter can cause valve and instrumentation plugging or erosion of piping.

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56	**02.01.03.11.**	CO2 containing toxic volatile metals (mercury, lead, or cadmium)	Most CO2 capture systems are likely to include mercury capture either as an upstream unit or an integral part of the CO2 capture system. It is not expected that mercury, lead or cadmium ion complexes will follow the CO2 concentrate stream during regeneration, other than by physical entrainment as aerosols, which can be eliminated by an in-line mist eliminator stage.	Presence of toxic volatile metals in the CO2 stream could classify it as a hazardous waste.
57	**02.01.03.12.**	CO2 containing pyrophoric compounds	Pyrophoric compounds can spontaneously ignite when in contact with air. Iron sulfide is one of the most common pyrophoric compounds associated with the oil and gas industry.	Pyrophoric materials can cause fires or explosions when exposed to air.
58	**02.01.03.13**	CO2 containing organic compounds	Trace amounts of organic compounds (derivatives or fragments of amine sorbents) could be carried over into the concentrated CO2 stream.	Organic compounds could feed microbial growth underground which can lead to plugging of wells and/or decreased permeability.
59	**02.01.03.14**	CO2 containing CO or H2	Traces of CO and H2 may occur when CO2 is captured from a pre-combustion operation such as those involving gasification..	CO and H2 are safety risks due to their combustibility in the presence of oxygen and potential for H2 embrittlement of metal components. CO2 combined with CO is more toxic than when CO2 or CO are separate. (Duncan 2012).
60	**02.01.04.00.**	Microbiological contamination	Microbiological contamination of injected fluid. Contamination of supercritical CO2 is considered unlikely due to its being a very good solvent. However, other fluids (like water) may be injected into the storage site that may be contaminated with microbes. Microbes are known to populate geologic strata to at least 2750 meters below the surface.	The introduction of microbes into the sequestration system may affect both the performance of the storage system and the endpoints considered. Microbial growth can lead to well plugging and/or decreased permeability.
61	**02.01.05.00.**	Schedule and planning **(See 11.03.00.)**		
62	**02.01.06.00.**	Pre-closure administrative control **(See 11.06.00.)**		
63	**02.01.07.00.**	Pre-closure monitoring of storage **(See 23.08.00.)**		
64	**02.01.08.00.**	Quality control **(See 11.08.00.)**		
65	**02.01.09.00.**	Accidents and unplanned events **(See 16.01.00.)**		
66	**02.01.10.00.**	Over pressuring	The CO2 injection process is greatly influenced by the target reservoir formation pore pressure. The formation pressure is considered over pressured if it is above the normal hydrostatic pressure for the given depth. Over pressuring may occur at any depth, naturally or artificially. Man-made overpressure may be accidental or deliberate. An example of deliberate overpressure is injecting gaseous CO2 in an aquifer at a faster rate than water can drain from the reservoir zone. In such a case the overpressure is caused by the injection activity (not natural processes). The maximum tolerable overpressure is calculated as a function of the desired storage volume and of a chosen safety factor below the critical fracturing gradient of the top seal rock. Deliberate overpressure induction is a mechanism for storing energy (associated with the pressure) for later extraction. An example of accidental overpressure is the depressurization of a storage reservoir where the CO2 is in liquid form, below but near the critical phase change pressure. The change of phase to gas creates a gas column that could exercise an unforeseen overpressure at the top of the gas column. 1. Deliberate over pressuring 2. Accidental over pressuring 3. Regional-scale over pressuring	Deliberate or accidental over pressuring during the operational phase will affect the initial geosphere conditions for a post-closure assessment. It has the potential to cause fractures in the sealing formation and hence provide migration pathways for the sequestered CO2. Induced fractures in the caprock can be created by over pressuring the reservoir. Fractures could be sealed in time by precipitation of newly formed minerals, but could also be re-opened as a consequence of new changes in stresses during storage of CO2.

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67	**02.02.00.00.**	Post-closure	Details of post-closure activities associated with sequestration.	Human activities post-closure may affect the likelihood of specific impacts being incurred.
68	**02.02.01.00.**	Post-closure administrative control **(See 11.07.00.)**		
69	**02.02.02.00.**	Post-closure monitoring of storage **(See 23.09.00.)**		
70	**02.02.03.00.**	Records and markers (long-term knowledge retention) **(See 11.04.00.)**		
71	**02.02.04.00.**	Reversibility	The degree to which the sequestered CO2 could be deliberately removed, if required. Either as an extreme remedial action, because the CO2 is required as a resource, or because its presence is impeding access to other geological resources.	The degree to which reversibility is considered in the design of a sequestration system may influence its long-term performance, by leaving viable boreholes in-situ after closure, for example.
72	**02.02.05.00.**	Remedial actions	Events and processes related to actions that might be taken following closure of a storage site to remedy problems that, either, are associated with its not performing to the standards required, result from disruption by some natural event or process, or result from inadvertent or deliberate damage by human actions.	The aim of possible future remedial actions will be to modify the performance and safety of the CO2 sequestration system.
73	**03.00.00.00.**	**CO2 PROPERTIES, INTERACTIONS & TRANSPORTATION**	This category of FEPs is concerned with those Features, Events and Processes that are relevant to the fate of the sequestered fluid. Carbon dioxides properties can vary greatly between conditions at depth and near surface, and a wide range of physical and chemical reactions can be important. The category is divided into three classes for the properties, interactions and transport of carbon dioxide.	This category is divided into three classes: 1. CO2 properties 2. CO2 interactions 3. CO2 transport These properties will have a significant impact on all of the risk calculations.
74	**03.01.00.00.**	CO2 properties	The fundamental physical and chemical properties of carbon dioxide, taking into account impurities. 1. CO2 properties changed by pressure 2. CO2 properties changed by temperature 3. CO2 properties changed by impurities 4. CO2 properties changed by reservoir geochemistry (i.e. CO2 migrating from quartz into calcite cemented sand)	Carbon dioxides properties can vary greatly with pressure, temperature and impurities, and an understanding of these properties is essential before the fate of sequestered fluid can be assessed.
75	**03.01.01.00.**	Physical properties of CO2	Physical properties of CO2 including density, viscosity, interfacial tension and thermal conductivity and their dependence on pressure and temperature. 1. CO2 density 2. CO2 viscosity 3. CO2 interfacial tension 4. CO2 thermal conductivity	The physical properties of CO2 determine the way in which it will behave in the environment once injected. Calculation of overpressure at constant rate injection and of injectivity at constant pressure injection are impacted by the choices of properties.

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76	**03.01.02.00.**	CO2 phase behavior	FEPs related to the phase behavior (gas, liquid, supercritical fluid) of CO2. The presence of contaminants in the injected CO2 (e.g. N2) and gas and hydrocarbons (e.g., in EOR and ECBM operations) in the reservoir will affect the phase behavior and partition of CO2 between different physical states. CO2 mixing with other fluids and gases, leads to modified flow behavior that is not fully understood (CCP 2009)	CO2 phase behavior is a primary consideration for modeling CO2 migration. CO2 is expected to be in the supercritical state under most sequestration scenarios.
77	**03.01.03.00.**	CO2 solubility and aqueous speciation **(See 03.02.13.02. and 03.02.13.06.)**	CO2 solubility is the amount of CO2 that can dissolve for given conditions in water. It can vary as a function of temperature, pressure and precise composition of the fluid (e.g. salinity, dissolved species/complexes, presence of hydrocarbons - e.g., EOR and ECBM). Changing temperature and pressure accompanying migration of CO2 can therefore influence CO2 solubility, potentially leading to gas exsolution. CO2 is present in the aqueous phase as: aqueous CO2; carbonic acid (H_2CO_3); bicarbonate (HCO_3^-); and carbonate (CO_3^{--}). Note that other dissolved ions (Na^+, Mg^{++}, Ca^{++}, etc.) are also involved and provide an array of linked, reversible reactions.	CO2 solubility has an impact on the chemical composition of formation fluids, pressure distribution, 'sorption' processes, mineral-fluid reactions and the overall storage capacity of CO2. Dissolved CO2 may migrate in a different manner to 'free' supercritical CO2. CO2 solubility in water and its partition between aqueous, gaseous, and organic phases controls the efficiency of diffusive transport and successive mineral reactions. The aqueous speciation of dissolved CO2 will impact upon the mobility of sequestered CO2 and associated contaminants.
78	**03.02.00.00.**	CO2 interactions	Potential interactions of carbon dioxide with solid, liquid or gaseous media.	A wide range of physical and chemical reactions can be important, and an understanding of these interactions is essential for the assessment of potential impacts.
79	**03.02.01.00.**	Effects of pressurization of reservoir on caprock **(See 02.01.10.00.)**	A storage reservoir will experience enhanced pressure due to injection of CO2. This may exceed original 'natural' pressurization due to hydrocarbon emplacement (EOR or ECBM, for example), or clay mineral transformations during diagenesis.	Over pressuring of the reservoir may involve leakage of CO2 through the caprock due to fracturing or enhanced interactions with CO2.
80	**03.02.02.00.**	Effects of pressurization on reservoir fluids	Increased pressurization caused by the injection of supercritical CO2 will affect the behavior of other fluids within the reservoir.	The potential importance of increased pressurization to enhanced oil and gas recovery indicates that it can modify the mobility of other fluids in the receiving reservoir.
81	**03.02.03.00.**	Interaction with hydrocarbons **(See 0.3.02.03.01 through 03.02.03.15)**	In EOR or ECBM sites, for example, hydrocarbons could be mobilized by CO2, by miscible displacement and transported to the near-surface. This is of particular relevance if enhanced oil recovery is an additional aim of the sequestration concept. Kolak and Burruss (2003) demonstrate that polyaromatic hydrocarbons (PAHs) can be mobilized by sequestration in deep coal beds. Sequestered CO2 can also precipitate asphaltenes from crude oil under certain conditions of composition, temperature and pressure. Such precipitation in the vicinity of injection wells can lead to loss of injectivity and even plugging of the wells.	Mobilized hydrocarbons may migrate to the near-surface environment. Precipitated asphaltenes can clog pores, reducing permeability and affecting fluid flow paths.

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82	**03.02.03.01.**	EOR attribute range	Technical screening guidelines for CO2 flooding: recommended (current projects range) Crude oil gravity, °API: >22 (27 to 44) Crude oil viscosity, cp: <10 (0.3 to 6) Crude oil composition: High percent of C_5 to C_{12} Reservoir oil saturation: >40% (15 to 70%) Type of formation: Relatively thin sandstone or carbonate unless dipping Permeability: Not critical if sufficient rates can be applied Depth/temperature: For miscible displacement, depth must be great enough to allow injection pressures greater than the minimum miscible pressure (MMP), which increase with temperature and for heavier oils (Meyer 2007). Oil formation volume factor (ratio reservoir barrels/stock tank barrels): 1.2 to 1.4 Reservoir barrels at subsurface conditions (at depth)	Operating outside the EOR attribute range could lead to low oil recovery. This could impact CO2 sequestration economics.
83	**03.02.03.02.**	EOR reservoir depth	Recommended depths of CO2 floods of typical Permian Basin oils CO2 Miscible Gravity, °API Depth >40 > 762 m (2500 ft) 32 to 39.3 > 853 m (2800 ft) 28 to 31.9 > 1006 m (3300 ft) 22 to 27.9 > 1219 m (4000 ft) <22 Fails CO2 screening CO2 Immiscible Gravity, °API Depth 13 to 21.9 > 549 m (1800 ft)	Operating conditions outside miscible range could lead to low oil recovery. This could impact CO2 sequestration economics and result in more CO2 recycling.
84	**03.02.03.03.**	EOR oil recovery	Typical oil recovery by recovery mechanism as a function of Original Oil in Place (OOIP) Primary: 6 to 15% OOIP Secondary: 6 to 30% OOIP Miscible CO2 EOR: 8 to 20% OOIP Remaining: 8 to 35% OOIP (Meyer2007) Miscible CO2 EOR: 7-23% OOIP Immiscible CO2 EOR: 9 to 19% OOIP (Meyer 2007)	Prior oil production and methods could impact CO2 EOR results and amount of CO2 that can be sequestered.
85	**03.02.03.04.**	EOR CO2 utilization	For field scale miscible CO2 EOR floods net (purchased) amount of CO2 required is estimated to be between 60 to 262 m^3 CO2/m^3 oil (2.5 to 11 MCF/STB) of incremental recovery with an average value of 143 to 167 m^3/m^3 (6 to 7 MCF/STB). For immiscible floods, actual incremental oil recovery has been on the order of 119 to 286 m^3/m^3 (5 to 12 MCF/STB) (Meyer 2007).	Increased CO2 demand per barrel of oil produced will impact EOR project economics. This could impact CO2 sequestration economics as well.
86	**03.02.03.05.**	EOR viscosity relations	Because the viscosity of CO2 at reservoir conditions is much lower than that of most oils, viscous instability will limit the sweep efficiency of the displacement and, therefore, oil recovery (Meyer 2007). Crude oil viscosity, cP: <10 (0.3 to 6)	Can lead to adverse hydrodynamic instabilities, such as fingering, which lead to vertical fluid stratification and reduced oil recovery (Meyer 2007). This could also result in more CO2 breakthrough and require more CO2 recycling.

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87	**03.02.03.06.**	EOR oil reservoir heterogeneity	Oil reservoir rock is extremely heterogeneous, exhibiting zones of high permeability in close proximity to those of low permeability. These permeability differences may be innate, that is caused by differences in pore structure at the time of geological deposition, or a product of fractures, natural or man-made (Meyer 2007)	Can decrease efficiency of oil recovery and CO2 sequestration.
88	**03.02.03.07.**	EOR hydrocarbon precipitation	CO2 injection encourages precipitation of asphaltenes or paraffins.	Precipitation of asphaltenes can clog pores, reducing permeability and affecting fluid flow paths. It can also cause plugging of boreholes.
89	**03.02.03.08.**	EOR miscibility	Flooding a reservoir with CO2 can occur either miscibly or immiscibly. Miscible CO2 displacement is only achieved under a specific combination of conditions, which are set by four variables: reservoir temperature, reservoir pressure, injected gas composition, and oil chemical composition (Meyer 2007). Miscible displacement is achieved at pressures above the minimum miscibility pressure (MMP). If the reservoir pressure is below the MMP, CO2 can still be injected, but the efficiency of the enhanced oil recovery process is adversely impacted. Typically this does not occur since, after primary depletion, water flooding operations commence which restore reservoir pressure to values above the MMP(Meyer 2007). 1. Miscible CO2 flooding 2. Immiscible CO2 flooding	Operating under miscible conditions results in significantly higher oil recovery than operating under immiscible conditions. Higher oil recovery improves economics of EOR and CO2 sequestration.
90	**03.02.03.09.**	EOR early CO2 breakthrough	Early breakthrough of CO2 results in production of significant amounts of CO2 and water along with oil. The alternating water and CO2 gas (WAG) approach is typically applied in CO2 EOR to minimize CO2 use (as it is purchased) and to avoid early breakthrough of CO2.	Breakthrough of CO2 increases operating costs due to the need to recycle the CO2 and can also result in lower oil recovery.
91	**03.02.03.10.**	EOR water alternating gas (WAG)	WAG involves alternating injection of water and gas (CO2) to optimize EOR performance. WAG ratios range: 1:1 to 5:1 (0.5:1 to 4:1 per NETL 2009) Slug range: 0.1% to 2% of reservoir hydrocarbon pore volume (NETL 2009) Cumulative CO2 volume: 15 to 30% of hydrocarbon pore volume (NETL 2009)	WAG ratio may have a positive or negative impact on oil recovery.

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92	**03.02.03.11.**	EOR injection water quality / attributes / chemistry	Water quality can impact EOR performance. Injection of low salinity water into an EOR reservoir where the sandstone cement consists of anhydrite could cause the anhydrite to convert to gypsum and its volume would increase up to 1.5 times resulting in decreased pore space and permeability. Injection microbial contaminated water could result in well plugging or decreased permeability due to microbial growth. Injection of corrosive water could result in corrosion of equipment, piping and borehole liners. Injection of hard water could lead to scale buildup.	Lower oil recovery. Corrosion, scale buildup or microbe growth in system equipment. Decreased permeability near injection wells.
93	**03.02.03.12.**	EOR injection water pressure	Water is denser than CO2. When changing from CO2 injection to water injection, a pressure differential needs to be overcome. To do so, the water supply header operates at a pressure in excess of the CO2 supply header pressure. This allows water to be throttled into the well, its pressure declining to the appropriate value once the CO2 is displaced from the wellbores (Meyer 2007).	System should be designed to provide the proper water injection pressure.
94	**03.02.03.13.**	EOR injection and production well pattern and spacing	The pattern is typically a 5-spot (one injection well in center surrounded by four production wells) or inverse 5-spot (one production well in center surrounded by four injection wells), or a variety of other patterns. Typically there are 0.5 to 4.0 production wells for every injection well. The spacing of injection and production wells refers to the area covered by the well pattern. It may be 8, 12, 16 or more hectares (20, 30, 40 or more acres).	Improper injection and production well spacing and pattern can lead to early CO2 breakthrough and/or low oil recovery.
95	**03.02.03.14.**	EOR intermittent CO2 supply	Intermittent CO2 supply can be caused by interruptions at the source, CO2 capture, compression, pipeline or wellhead.	Intermittent CO2 supply can negatively impact sweep efficiency of EOR and therefore make sequestration less attractive.
96	**03.02.03.15.**	EOR flood type	CO2 flooding types include gravity stable and conventional piston flooding. In gravity stable flooding, CO2 is injected in the top of a reservoir (dome) as a supercritical fluid or dense gas and builds an oil bank by mobilizing residual oil downward as the CO2 cap expands. It is important to maintain a relatively uniform front and avoid coning. In the conventional piston flooding, CO2 is injected into an oil reservoir and builds an oil bank by mobilizing residual oil horizontally as the CO2 plume expands. 1. Gravity stable CO2 flooding 2. Piston CO2 flooding	Flooding should be optimized to maintain a relatively uniform front and avoid coning or CO2 early breakthrough (profile control).
97	**03.02.04.00.**	Displacement of saline formation fluids	Injection of CO2 into a geologic formation may result in displacement of saline formation fluids into potable water supplies. Limitations on the pressure in a formation (for seal integrity) will mean that existing fluids are displaced/replaced. Displaced fluids are highly likely to be saline. Because the pressure wave created by injection travels much further than the physical CO2 front, displacement of saline formation fluids can occur at locations outside the CO2 storage area. Inter-connection of aquifer systems may enable saline fluids to enter potable water formations. For significant storage to be possible, it is necessary for a significant amount of the native pore space fluid to be displaced from the reservoir over the injection period. This may occur either by production of fluids (oil or gas), by deliberate production of formation water, and/or by	Displaced saline formation fluids may contaminate near-surface aquifers with subsequent impacts, such as contamination of potable water supplies.

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98	**03.02.05.00.**	Change in mechanical processes and conditions	Features and processes related to the mechanical processes and conditions resulting from the injection of CO2 that affect the rock, boreholes and other engineered features, and the overall mechanical evolution with time. This includes the effects of hydraulic, mechanical and thermal loads imposed on the rock by the injected CO2. Injection of CO2 into a reservoir can cause (directly or indirectly) changes of the geomechanical properties of the reservoir rock. Direct changes can be due to change of reservoir pressure and temperature (PVT system). Indirect changes (of rock properties) might result from geochemical and mineralogical changes after storage of CO2.	Mechanical changes of the reservoir resulting from CO2 injection (such as generation of fractures, reactivation of fractures/faults, changes of bulk elastic properties and effective reservoir) could lead to subsidence/uplift (at surface), induced seismicity, changes in migration pathways, even burst/leakage of the seal. Examples of other relevant processes are: borehole lining collapse; rock volume changes, leading to cracking
99	**03.02.06.00.**	Induced seismicity	Injection of CO2 may cause and trigger seismic events and earthquake hazards through processes such as reducing friction at existing faults. This may occur both in seismically active areas and in areas characterized by a low background seismicity (reactivation of ancient fault planes, changes in the orientation, fluid-pockets occurrence). This FEP includes micro seismicity. Induced macro-seismicity activity is a function of existing regional and local stresses, of porosity structure, and of imposed injection stresses. Induced macro-seismicity is less likely if the injection formation is dominated by intergranular and not fracture porosity. The problem of seismicity might be more serious when CO2 is injected into a reservoir in tectonically active regions with high density of active faults (Damen 2006). 1. Induced macro-seismicity 2. Induced micro-seismicity 3. Seismicity tied to activation of an existing structure (fault/fracture) 4. Seismicity tied to creation of a new structure (fault/fracture)	Seismicity can introduce sudden physical changes to the sequestration system and may expose any local population to earthquake hazards. Potential effects of reservoir-induced seismicity (RIS) are damage to the caprock and wells , which might cause CO2 leakage , and damage to building and infrastructure (Damen 2006). In a reservoir that is under high tectonic stresses, any significant reduction of pressure (pressure acting between individual rock particles) may trigger faults. This may lead to uplifting or down-faulting of the surface (Damen 2006).
100	**03.02.07.00.**	Subsidence or uplift	Injecting the CO2 may cause acidification of formation water, leading to mineral dissolution and subsidence. This is of particular relevance to shallow storage sites. Chemical compaction or dissolution of the reservoir rock will particularly be a matter of concern in carbonate rocks with high porosity (Damen 2006). Injection of large quantities of CO2 into a confined aquifer may increase pore pressure and lift the overlying rocks upwards. It is not envisaged that uplift will take place in a CO2 reservoir as long as the maximum storage pressure is kept below the geostatic pressure (Damen 2006). 1. Subsidence 2. Uplift	Deformation may affect geological processes and may result in impacts of concern at the surface. Dissolution of the reservoir rock (chemical compaction) can lead to the reservoir caving in under the weight of the overburden formation (Damen 2006) Vertical subsidence or uplift above large reservoirs could affect lake levels and shift streams in lowland areas with low topographic relief. Subsidence or uplift could damage buildings or farmland.

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101	**03.02.08.00.**	Thermal effects on the injection point	Temperature of the injected fluid could result in geological modification of the region around the point of injection due to thermal gradients. 1. Cooling due to CO2 changing from supercritical to gas phase. 2. Injected CO2 may be 25 to 50°C cooler than the in-situ temperature.	These thermal effects could influence the mobility of the injected CO2 and impurities.
102	**03.02.09.00.**	Reservoir water chemistry	Water phase geochemistry of sequestered CO_2. This includes the solubility trapping of CO_2 in water (H_2O) to form carbonic acid (H2CO3). Subsequent ionic trapping of carbonic acid with hydroxide ions (OH^-) forms bicarbonate ions (HCO_3^-), which can react in turn with further hydroxide ions to form carbonate (CO_3). 1. Formation of carbonic acid (H_2CO_3) 2. Formation of bicarbonate ions (HCO_3^-) 3. Formation of carbonate (CO_3)	Modification of the water phase geochemistry can disturb the equilibrium between the water and solid phase of the reservoir and result in further geochemical (for example, solid phase geochemistry) and physical changes with resulting implications for the long-term performance of the sequestration system.
103	**03.02.10.00.**	Interaction of CO2 with chemical barriers	Chemical barriers (pH, Eh-pH, ion exchange) may exist in aquifers to retard the migration of CO2 from depth. The precipitation of CO2 bearing solids may result from such interactions. 1. pH barrier 2. Eh-pH barrier 3. Ion exchange barrier	Such barriers will affect the rate of migration of CO2 from depth.
104	**03.02.11.00.**	Sorption and desorption of CO2 (CO2 interaction with coal seams)	The sorption and desorption of CO2 on geological materials. Sorption onto coal and the displacement of methane (CH4) is the primary mechanism behind the enhanced coal bed methane recovery (ECBM) method for geological CO2 sequestration.	The rate of sorption and desorption of CO2 on geological materials affects its mobility and therefore the performance of the storage system.
105	**03.02.11.01.**	ECBM sorption of CO2 on coal and release of methane	Based on the Langmuir isotherm, CO2 has higher affinity to coal and therefore displaces CH4 adsorbed on the coal. 2-3 moles CO2 adsorbed on coal for every mole of CH4 desorbed. CO2 adsorption: up to 41 Nm^3/tonne coal (1400 scf/st coal) CH4 release: up to 13-15 Nm^3/tonne coal (450-500 scf/st coal) at 22°C 72°F) and 0-7 MPa (0-1000 psi)). The CO2/CH4 sorption ratio of coal varies depending on the rank of coal. Typical CO2/CH4 sorption ratios for various coals are as follows: Low volatile bituminous: 1.1 Medium volatile bituminous: 1.5:1 High volatile A bituminous: 3:1 High volatile bituminous: 6:1 Sub bituminous: 10:1	Adsorption of CO2 on coal can have a positive effect on CO2 sequestration.
106	**03.02.11.02.**	ECBM desorption of CO2 from coal or other solids	CO2 desorption can occur with decreased pressure.	Release of CO2 could lead to leakage.
107	**03.02.11.03.**	ECBM coal swelling	The chemical reactions and physical processes that occur during CO2 injection into coal seams and their impact on the integrity of the coal seams are not well understood. One of the reactions is swelling of the coal matrix when injecting CO2. (Damen 2006) When CO2 is injected into a coal seam, the coal matrix swells causing the cleat permeability to decrease.	Coal seam swelling may cause a reduction in permeability and injectivity. Swelling might also induce stresses on the overlying and underlying rock strata in non ideal coal seams (thin, low permeability and highly faulted), that could cause faulting and possible migration pathways out of the coal seam (Damen 2006).
108	**03.02.11.04.**	ECBM release of polyaromatic hydrocarbons (PAH) from coal seams	Polyaromatic hydrocarbons are chemical compounds that consist of aromatic rings. They are found in oil, coal and tar deposits. They tend to be released as a by-product of coal fires.	Toxicity issues and operation issues with decreased permeability.

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109	**03.02.11.05.**	ECBM coal seam dewatering	As a coal seam is dewatered, its pressure decreases. Cleat permeability increases. Coal matrix shrinks, opening up cleat fractures. Assume that the coal cleats are originally 100% saturated with water. Recommendation for ECBM: Coal seams with low water saturation (Bachu 2008)	Coal dewatering produces large quantities of water that must be properly treated and disposed of. In some cases, this may be a limiting factor in obtaining environmental permits and take a significant toll on project economics.
110	**03.02.11.06.**	ECBM original gas in place	Original gas (methane) in place (OGIP) depends on the rank of coal. Free gas occurs within natural fractures. Dissolved gas occurs in water within the natural fractures. Adsorbed gas occurs within the coal matrix Adsorbed gas typically represents over 95% of total. (Mansourine 2003) Coal bed methane may be formed by bacteria (biogenic methane) at depths less than 300 meters, or formed by heat and pressure transformation of coal organic matter (thermogenic methane) at greater depths in higher-rank coals. Thermogenic methane frequently contains trace amounts of H_2O, CO_2, N_2 and H_2S. Existing gas in place = original gas in place - previous gas production. Recommendation for ECBM: Methane-saturated seams should be preferred from a methane production perspective. From a storage perspective, under saturated coal seams can still be effective (Bachu 2008).	OGIP impacts the amount of methane available for ECBM recovery.
111	**03.02.11.07.**	Previous working of the coal seam	Primary CBM takes out 20-60% of the original gas in place (OGIP). CO2 ECBM can recover an additional 30%. Up to 80-90% of OGIP can be recovered with primary CBM plus CO2 ECBM. Production stages of a coal bed methane well 1. Dewatering stage 2. Stable production stage 3. Decline stage (Mansourine 2003) 4. CO2 injection stage	Wells selected for ECBM CO2 injection should be near depletion to optimize CBM and ECBM performance.
112	**03.02.11.08.**	ECBM coal seam pressure	Coal seam hydrostatic pressure increases with depth. CO_2, N_2 and water injection increase hydrostatic pressure. Dewatering and methane production decrease hydrostatic pressure. CO_2, CH_4, N_2 and H_2S adsorption capacity of coal increases with coal seam hydrostatic pressure.	Gas adsorption is pressure dependent. The pressure profile in the reservoir must be understood and the injection operation designed appropriately. Gas adsorption of coal increases with pressure. Gas desorption of coal increases as pressure decreases. As reservoir pressure decreases, the rate at which CH_4 desorbs increases. However, CO_2 adsorption decreases with decreased pressure. At supercritical pressures, CO_2 adsorption may be replaced by absorption as CO_2 diffuses in coal. CO_2 is a coal plasticizer, lowering the temperature required to cause the transition from a glassy, brittle structure to a rubbery, plastic structure. The transition temperature may drop from ~400°C at 3MPa to <30°C at 5.5 MPa. Coal plasticization, or softening, destroys any permeability that would allow CO_2 injection. (Bachu 2006).
113	**03.02.11.09.**	ECBM coal seam temperature	Coal seam temperature increases with depth. CO_2 adsorption is an exothermic reaction and will provide a heat source, at least during the active injection phase of the project. As temperature of the coal seam increases, the adsorption of CO_2 decreases.	Impacts CO_2 adsorption and methane release.

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114	**03.02.11.10.**	ECBM coal seam fluid pH	The pH of aqueous solutions affects t surface of material it is in contact with. In the case of coal, at a high pH value, the carbonaceous surface assumes a net negative charge. At a low pH, the carbonaceous surface assumes a net positive charge. Theoretically, a pH of 9 would favor and a pH of 2 would disfavor the aqueous capture of CO2.	pH of water in the coal seam may impact CO2 adsorption.
115	**03.02.11.12.**	ECBM injection and production well pattern and spacing	The most common drilling pattern is a 5-spot (injection well in the center and production wells in the corners or inverse 5-spot (injection in the corners and production in the center). Drilling on 16, 65 or 233 hectare (40, 160 or 640 acre) spacing. When injecting CO2, it is important to allow sufficient time for displacement of the methane (locating production wells far away enough from the injection wells).	Impacts the sweep efficiency of ECBM and the effective sorption of CO2.
116	**03.02.11.13.**	ECBM injection strategy	Constant injection rate or variable injection rate "huff and puff"(alternating starting and stopping CO2 injection over time.	Impacts the sweep efficiency of ECBM and the effective sorption of CO2.
117	**03.02.11.14.**	ECBM early CO2 breakthrough	Early breakthrough of CO2 can be caused by high permeability areas in the coal seam or improper well pattern/spacing.	Impacts the sweep efficiency of ECBM and increases costs due to the need for excess CO2 recycling.
118	**03.02.11.15.**	ECBM coal seam thickness	For ECBM at least one coal seam should be at least 0. 5 m (1.5 ft) thick. However, the thicker the seam, the more likely it could be mineable. Recommended for ECBM: Concentrated coal deposits (few, thick seams) are generally favored over stratigraphical dispersed beds comprising multiple, thin seams (Bachu 2008).	Seams less than 0.5 m (1.5 ft) thick can limit injectivity.
119	**03.02.11.16.**	ECBM complex structural geology of coal seam	Complex structural geology can make ECBM more difficult to model, less efficient to implement and more susceptible to leakage. Recommendation for ECBM: Simple structure. The reservoir should be minimally faulted and folded . The coal seams should be laterally continuous and vertically isolated from surrounding strata to prevent migration of excess CO2 and CH4 into adjacent aquifers and possibly to the surface (Bachu 2008).	Potential for CO2 leakage and lower methane yields.
120	**03.02.11.17.**	ECBM CO2 injection into mineable coal seams	CO2 ECBM is normally applied to coal seams that are too thin or too deep to be mined.	CO2 ECBM in mineable coal seams will complicate the recovery of those coal reserves. However, removing methane decreases the explosion possibility for future mining.
121	**03.02.11.18.**	ECBM coal seam permeability	The permeability of coal varies in two basic ways: 1. Phase relative permeability effects 2. Change in the effective stress within the seams (Mansourine 2003) Cleat permeability is primarily controlled by the prevailing horizontal stresses. ECBM wells that produce little water or gas may indicate low permeability. Recommended permeability for ECBM: 1 to 5 mD (Bachu 2008). Coal permeability decreases with depth, such that injectivity	Low permeability makes CO2 ECBM more difficult and more expensive.

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122	**03.02.11.19.**	ECBM coal porosity	Micro-porosity: < 2 nm pore diameter impacts sorption Meso-porosity: >2 nm <50 nm pore diameter impacts diffusion Macro-porosity (fracture porosity): > 50 nm impacts Darcy flow Induced fractures: pipe flow (Mansourine 2003) Cleat porosity represents the initial water storage volume in the coal seam.	Coal bed porosity and permeability increases as reservoir pressure is lowered and gas production occurs.
123	**03.02.11.20.**	ECBM coal seam heterogeneity	Permeability can vary by more than an order of magnitude in coal seams.	Heterogeneity in permeability can result in CO2 early breakthrough, limit CO2 storage capacity and limit methane recovery.
124	**03.02.11.21.**	ECBM coal seam vertical and horizontal injectivity	Vertical and horizontal injectivity in coal seams is largely determined by the cleat size and cleat angle.	Vertical and horizontal injectivity may determine whether to use vertical or horizontal type wells for CO2 injection.
125	**03.02.11.22.**	ECBM CO2 storage capacity of coal	Typical sorption of coal can be up to 41 Nm^3/tonne (1400 scf/st) at 22°C and 0- 6.9MPa (0-1000 psi).	Depending on the objective of CO2 ECBM, the CO2 storage capacity can have a positive or negative impact. If the objective is to minimize CO2 consumption/cost it can be a negative. If the objective is to maximize CO2 sequestration, it is a positive.
126	**03.02.11.23.**	ECBM coal bed methane composition	Coal bed methane tends to be sweet (no H2S). It contains small amounts of CO2 and nitrogen.	Impacts gas treatment facilities on surface and value of coal bed methane.
127	**03.02.11.24.**	ECBM induced fracturing of coal	Coal is an extremely stress-sensitive rock	Limits CO2 injection pressure.
128	**03.02.11.25.**	ECBM nitrogen injection into coal seam	Nitrogen has a lower affinity to coal than CH4. Nitrogen injection lowers the partial pressure of CH4 which allows CH4 to diffuse through the coal matrix with greater ease, improving recovery of CBM at a faster rate.	Nitrogen is not a problem in ECBM as a minor component of CO2. It will lower the partial pressure of methane and allow more methane to be released and recovered. Some of the nitrogen injected with CO2 may end up in the coal bed methane, resulting in a lower value product.
129	**03.02.11.26**	ECBM coal fines generation and transport	Induced fracturing of coal seams can lead to fines generation. These fines can be mobilized by injected gases or fluids. Some types of medium- and low-volatile bituminous coals are weaker, and have a greater tendency of generating fines, than other coals.	Coal fines can: 1. Pug and reduce coal seam permeability 2. Plug and reduce fracture conductivity 3. Plug submersible pumps 4. Erode ECBM systems 5. Accumulate in ECBM separators 6. Require disposal (Palmer 2008)

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130	**03.02.11.27**	ECBM coal plasticization	CO2 is a coal plasticizer, lowering the temperature required to cause the transition from a glassy, brittle structure to a rubbery, plastic structure. The transition temperature may drop from ~400°C at 3MPa to <30°C at 5.5 MPa. (Bachu 2006). Recommendation for ECBM: Avoid deep ECBM sites that have CO2 supercritical pressures and temperatures above 30°C (Bachu 2008).	Coal plasticization, or softening, destroys any permeability that would allow CO2 injection. (Bachu 2006).
131	**03.02.12.00.**	Heavy metal release	Heavy metal ions may be dissolved in formation fluids or adsorbed on rock/mineral surfaces. Complexation may occur between CO2 and heavy metals dissolved in formation fluids. The influence of dissolved CO2 on pore water chemistry can also reduce the pH and change the equilibrium between sorption/desorption of metals, thereby resulting in significant release of these metals.	This process has the potential to release heavy metals, which may then migrate to the near-surface environment with resulting impacts of interest. These heavy metals will also change pore water chemistry, which could impact on carbonate complexation.
132	**03.02.13.00.**	Mineral phase **(See 03.02.13.01. through 03.02.13.06.)**	Geochemistry of the mineral phase relevant to sequestered CO2, including ion exchange and mineral dissolution.	Geochemical reactions between sequestered CO2 and the mineral phase of the storage system will affect the evolution of the system and the sorption (and therefore mobility) of the CO2.
133	**03.02.13.01.**	Mineral dissolution and precipitation **(See 03.02.13.02.; 03.02.13.03 and 03.02.13.06.)**	The dissolution of minerals (grains or cement) due to the addition of CO2 (an acid gas) to the geochemistry and precipitation. For example, the dissolution of albite and precipitation of calcite modeled for the Sleipner site by Gaus et al. (2003). 1. Mineral dissolution and precipitation in the reservoir 2. Mineral dissolution and precipitation in or near the borehole 3. Mineral dissolution and precipitation in the caprock 4. Mineral dissolution and precipitation in faults and fractures	CO2 reaction with the host rock will modify: the porosity and permeability of the reservoir; fluid flow (direction or velocity); mechanical properties (e.g. strength); and CO2 storage capacity.
134	**03.02.13.02.**	Precipitation of carbonate minerals (scale buildup)	CO2 reacts with brine to form hard water which can lead to scaling in or near a production well. Calcium carbonate and magnesium carbonate can be formed when HCO_3^- reacts with Ca^{2+} or Mg^{2+}.	Scale buildup can cause reduced porosity and permeability in the reservoir, especially near the borehole.
135	**03.02.13.03.**	Salt precipitation	Dry CO2 can pick up moisture from high salinity brines in the reservoir. This increases the salinity of the brines. (CCP 2009)	Increased salinity of brines can lead to precipitation of salt in pore space, which can decrease reservoir permeability and impair injection rates of CO2. (CCP 2009) "Dry out" and "salt out" may cause reduced porosity and permeability in the reservoir, especially near the borehole.
136	**03.02.13.04.**	Ion exchange (mineral dissolution and precipitation) **(See 03.02.13.02.; 03.02.13.03 and 03.02.13.06.)**	The process of exchanging one ion in the liquid phase for another ion on a charged, solid substrate. Injected CO2 may perturb ion exchange equilibrium between relevant minerals (such as sheet silicates) and the pore fluid. Some cations may be released to the pore fluid and others fixed as a consequence.	Disturbance of the rock-pore fluid equilibrium may affect the capacity of the rock to store CO2.
137	**03.02.13.05.**	Desiccation of clay	CO2 is likely to be dried to prevent corrosion during transport. Injection of dry CO2 will cause it to take up water from the pores of the host formation and overlying rocks. It has the potential to suck water out of an overlying clay. CO2 can also be adsorbed by clay.	If clay dehydrates, it will shrink and crack. This might aid CO2 migration upwards.

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138	**03.02.13.06.**	Mineral dissolution	The dissolution of minerals (grains or cement) due to the addition of CO2 (an acid gas) to the geochemistry. 1. Mineral dissolution in the reservoir 2. Mineral dissolution in or near the borehole 3. Mineral dissolution in the caprock 4. Mineral dissolution in faults and fractures	CO2 reaction with the host rock will increase: the porosity and permeability of the reservoir; increase fluid flow (direction or velocity); decrease mechanical properties (e.g. strength); and increase CO2 storage capacity.
139	**03.02.14.00.**	Gas chemistry (CO2 interacting with gases in the reservoir)	Gases such as CO2, methane and H2S, will occur naturally in the geosphere, either sorbed onto minerals, dissolved in formation fluids or as a free gas phase. Gas solubility will depend upon pressure, temperature and the salinity of the formation fluid. 1. CO2 interacting with free gases in the reservoir 2. CO2 interacting with gases sorbed onto minerals 3. CO2 interacting with gases dissolved in formation fluids 4. CO2 interacting with gaseous hydrocarbons in the reservoir	Gases naturally present in the geosphere could affect the behavior of CO2 injected into a storage reservoir and could accompany CO2 along potential migration paths.
140	**03.02.15.00.**	Gas stripping in overlying formations	CO2 migration through the reservoir and into the overlying barrier sequence could result in the CO2 stripping other gases entrained within the sediments. This could include: 1. Radon stripping 2. Methane (CH4) stripping, and 3. Hydrogen sulfide (H2S) stripping.	The presence of other gases in a leaking CO2 gas stream is important in deciding the level of CO2 leakage that can be tolerated and may constitute an important hazard. H2S acts as an odorant for early detection of CO2 and any stripped gases.
141	**03.02.16.00.**	Gas hydrates	Gas hydrates are ‘ice-like’ solids that form at low temperatures and high pressures. They are formed of ‘cages’ of water molecules surrounding a gas molecule. CO2 can form hydrates in the presence of water. The prevention of hydrate formation in the well during startup will need to be considered. It is likely that methanol spacers will need to be used. (CCP 2009) Hydrate potentially could form in the well when starting back up after a shut down. During the process of shutting down, measures should be taken to mitigate the formation of hydrates when starting back up. Often a methanol "cap" is pumped in the top of the tubulars. (CCP 2009) As a consequence of well control using a brine or similar fluid, there can be intermixing of the CO2 and the well control fluid that could result in hydrate formation or hydrate blocks, Using hydrate inhibited fluids or having operational practices that minimize the amount of CO2 inflow during workovers should be considered. (CCP 2009) There is a lack of experimental data and models for predicting the water solubility of CO2 at temperatures below 10°C. Moreover, there is a need to investigate hydrate formation conditions with CO2 near and below water saturated conditions in the presence of carbon steel surfaces. (DNV CO2PIPETRANS Phase 2) 1. Gas hydrates formed below deep water 2. Gas hydrates formed below permafrost	Cooling of the reservoir (e.g. by injecting cold CO2 or through adiabatic expansion) well below normal in-situ temperatures might stabilize gas hydrates. Their growth might seal fluid flow pathways (at least temporarily). If CO2 is injected below deep water or permafrost, then rising CO2 might hit the hydrate stability zone before escaping to the ocean or air, so hydrates could act as a secondary chemical barrier. Similarly, storage could be focused on actively forming CO2 hydrate as a stable, immobile phase to lock up the CO2 (Koide et al., 1997).

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142	**03.02.17.00.**	Biogeochemistry	Features and processes related to the biological/biochemical processes that affect the CO2, borehole seals and rock/pore fluid, and the overall biological/biochemical evolution with time. This includes the effects of biological/biochemical influences on the CO2 and engineered components by the surrounding geology. Microbes exist in the subsurface and are used in hydrocarbon operations to improve hydrocarbon recovery (e.g., in EOR and ECBM operations). Microbes can also catalyze geochemical reactions, including methanogenesis, but the latter reaction is thermodynamically unfavorable and is unlikely.	Examples of relevant processes are: - microbial growth; - microbial/biological mediated processes; and - microbial/biological effects of evolution of redox (Eh) and acidity/alkalinity (pH) , etc. This FEP has probably low relevance to the safety/fate of CO2. However, CO2 releases may affect/impact microbe populations being used in independent hydrocarbon-recovery enhancement projects.
143	**03.02.18.00.**	Microbial processes	Microbes can metabolize CO2, for example, methanogenic microbes use H2 to reduce CO2 to methane (CH4), a process called methanogenesis. These microbes need anaerobic conditions. Microbes can produce SOx, NOx, and CO under oxic conditions and H2S and CH4 under anoxic conditions.	Methanogenesis, if it occurs, could affect the pressure distribution of CO2. The fate and impact of the CH4 produced may be an endpoint of interest in itself.
144	**03.02.19.00.**	Biomass uptake of CO2	If sequestered CO2 migrates to the biosphere, it can be taken up by microbes, plants and algae (including phytoplankton).	This mechanism may provide a sink for CO2 that has migrated from the sequestration system.
145	**03.02.20.00.**	Mobilization of particulates by CO2	Insoluble particulates could be mobilized by CO2 via chemical hydrodynamic interaction with the reservoir rock.	Particulate mobilization could increase permeability at the point of mobilization, but it could also decrease permeability in reservoir locations where particulates are deposited or trapped.
146	**03.03.00.00.**	CO2 transport	Transport processes that may affect sequestered carbon dioxide and associated impurities.	An understanding of those processes that could transport carbon dioxide, and associated impurities, within the geosphere, near-surface and surface environments is fundamental to the assessment of long-term performance and safety.
147	**03.03.01.00.**	Advection of free CO2	Advection of free CO2 occurs in response to differences in pressure. The pressure difference may be due to differences in the pressure of injected CO2 and formation pressures. The rate and direction of advection is affected by the physical properties of the rock, such as porosity and permeability. Advection may also occur though fractures. Fracture flow will be episodic with high transport efficiencies. Resealing of fractures (for example by cementation) will reduce and ultimately block fluid flow. 1. Advection causing change in CO2 migration direction 2. Hydrodynamic gradients	Advective flow is a key transport process for migrating CO2, and associated contaminants, in the geosphere (reservoir, surrounding and overlying rock), near-surface and surface environments.

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148	**03.03.01.01.**	Fault valving and reactivation	Fault valving is a process resulting from gradual build up of pore pressure due to fluid generation, causing the subsequent opening of a fault along with fluid escape towards surface. This mechanism has been recognized as causing earthquakes in many parts of the world, as a result of hydrocarbon generation (e.g., in EOR or ECBM operations) or infiltration of other fluids. 1. CO2 leakage through an existing open fault 2. CO2 leakage through a reactivated fault	Large releases of pore fluids may occur during fault valving episodes.
149	**03.03.02.00.**	Buoyancy-driven flow	Different relative densities of fluids in a geological system will result in buoyancy-driven flows as less dense fluids will have a tendency to flow upwards. The density of fluids will depend on its temperature and pressure. If a stream of CO2 begins to move upward, expansion of the volume and decrease in the density provides increasing energy to drive flow upward, which can result in gas lift, a strong process for moving fluid upward (NETL 2010). 1. CO2 exceeding reservoir spill point 2. Lateral CO2 flow across top of reservoir 3. CO2 buoyancy putting pressure on caprock	Carbon dioxide can be less dense than water, which may cause injected CO2 to flow upwards and accumulate above the water phase below the caprock of a reservoir. Water with dissolved CO2 is more dense than water, which can result in stratification of water bodies into which CO2 may leak, if conditions are suitable.
150	**03.03.03.00.**	Displacement of formation fluids	This depends on interfacial tension and capillary pressure. Capillary pressure is the pressure difference existing across the interface separating two immiscible fluids due to interfacial tension. The interfacial tension itself is caused by the imbalance in the molecular forces of attraction experienced by the molecules at the surface and is a function of temperature and pressure. At a given pressure, increased interfacial tension values between water and CO2 will make larger pores accessible to CO2 (this is only valid for water-wet systems). The change from a water-wet system to a CO2-wet system has an effect on capillary forces (i.e. displacement of water by enhanced pressure versus CO2 injection with less capillary pressure) and the displacement capacity (i.e. as a non-wetting fluid, CO2 will have less displacement capacity). If the injection velocity is high, effects of capillary forces are small.	Interfacial tension and capillary pressure determine the location of CO2 within the pore spaces of the reservoir and the displacement capacity of the reservoir.
151	**03.03.04.00.**	CO2 dissolution in formation fluids	The process of dissolution of CO2 in formation fluids. The rate of dissolution depends on factors such as the interfacial area between the CO2 and the formation fluids and temperature.	Dissolution in formation fluids can be an important positive process in decreasing the free CO2 remaining in the reservoir.

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152	**03.03.04.01.**	CO2 exsolution from formation fluids	Long-term risks might result from the gravitational sinking of dense CO2 saturated brines; if they come into contact with salt formations this could lead to a degassing of the formation water and the ascent of CO2 outside of the original closed storage structure. (CO2STORE, page 68) Exsolution can also occur under significant (large) changes in pressure or temperature. The risk of major changes in pressure or temperature in a deep reservoir is very low.	Displaced brine containing dissolved CO2 flows to the surface and releases CO2 to the atmosphere or ocean.
153	**03.03.05.00.**	Water mediated transport	Processes related to the transport of CO2, and associated contaminants, in groundwater and surface water, including advection, dispersion and molecular diffusion. Advection is the process by which contaminants are transported by the bulk movement of the water in which they are dissolved. Advective groundwater flow can occur along connected porous regions, such as fractures and faults. Dispersion is the collective name for the consequences of a number of processes that cause 'spreading-out' of CO2, and associated contaminants, dissolved in water in all directions, superimposed on the bulk movement predicted by a simple advection model. It results in a spatially distributed contaminant plume. Diffusion is the process whereby chemical species move under the influence of a chemical potential gradient (usually a concentration gradient).	The transport of CO2, and associated contaminants, within groundwater is likely to be a key migration process and therefore an important consideration in determining performance and safety. CO2 dissolves in brine at CO2/brine interface and brine transports CO2 out of closure.
154	**03.03.06.00.**	CO2 release processes	Processes by which CO2 is lost from the sequestration system. Once in the near-surface, changes in pressure and temperature result in the potential for phase changes and degassing, with resulting changes in the transport properties of sequestered CO2. Examples of CO2 release processes include: 1. Surface blowouts (rapid release of CO2) 2. Undersea blowouts (rapid release of CO2) 3. CO2 geysers (such as Crystal Geyser in Utah) 4. Submarine gas release (Slow or moderate release of CO2) 5. Diffusion through soil (slow release of CO2) 6. CO2 released through mud volcano or mud flow. In fine-clastic unconsolidated rocks, suspensions could form and cause mud-volcanism and mud flows. (CO2STORE p.68)	The potential for CO2 to be lost from a sequestration system will determine the performance of that system. Rapid release of CO2 will tend to shoot CO2 into the atmosphere where it will quickly mix with air and diffuse. Slow release of CO2 will diffuse into soil gas. Moderate release of CO2 will tend to blanket the ground unless there is sufficient air circulation (wind). Thus moderate release of CO2 can be a greater safety risk than rapid or slow release.
155	**03.03.06.01.**	Limnic eruption	The rapid turnover and degassing of CO2 from a surface water body. Due to the high solubility of CO2 in water, a lake can dissolve a volume of CO2 that, in gaseous form, is more than five times its volume. CO2 rich water is denser that pure water which can result in an unstable stratification. A drop in temperature will reduce the solubility of CO2 in water. If the water reaches its solubility limit as a result, bubbles will nucleate. As the bubbles rise and grow, a chain reaction occurs where a sudden ex-solution of CO2 can result in a rapid degassing of the water body with an eruption of rising, expanding bubbles. Limnic eruptions can be triggered by events such as landslides that disturb the unstable stratification.	Limnic eruption provides a release mechanism for CO2, migrating from a storage system to the atmosphere. Natural limnic eruption events can be catastrophic. On the 29th of August 1986, a massive limnic eruption from Lake Nyos in Cameroon resulted in 1800 deaths as the CO2 smothered local villages. The CO2, which is volcanic in origin, seeps through the lake bed sediments and builds up in the lower strata of the water column. The Lake Nyos sudden release involved an estimated 240,000 tonnes of CO2 (Damen 2006).

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156	**03.03.07.00.**	Co-migration of other gases	Surface seepages of CO2 may contain significant amounts of other gases due to co-migration, such as hydrogen sulfide (H2S). This is especially the case where the CO2 reservoir is a reducing chemical environment. H2S is derived from the hydration of sulfide minerals (e.g. FeS2) or from the chemical reduction of aqueous sulfate species. H2S is highly toxic and therefore potentially harmful to the biosphere. Even in low concentrations it is deleterious to long-term health (human/animal), in addition to being extremely unpleasant.	The co-migration of other gases to the surface environment may cause areas of leakage to become uninhabitable – at least temporarily. The detection of H2S provides a quick (non-analytical/aesthetic) test for CO2 escape and thus can be used as a "marker" gas.
157	**03.03.08.00.**	Diffusion of CO2	Diffusion is the net movement of a constituent in response to a concentration gradient. Diffusion always results in mass transfer from the region of high concentration to regions of low concentration. Diffusion will occur in conjunction with flow, but it will also occur in the absence of flow, and it is the primary transport mechanism in the absence of flow (as through a highly impermeable rock).	Diffusion is a transport process by which CO2 can access portions of the reservoir that are not directly exposed to advective flow. It can also be a primary transport mechanism in highly impermeable rocks such as caprock.
158	**04.00.00.00.**	**GEOSPHERE**	This category of FEPs is concerned with the geology, hydrogeology and geochemistry of the geosphere. The category covers the reservoir, overburden and surrounding rock up to the near-surface which is considered in a separate FEP category. Taken together, the FEPs in this category describe what is known about the natural system prior to sequestration operations commencing. The category is divided into three classes: Geology, Fluids, and Geochemistry.	This category is divided into three classes: 1. Geology 2. Fluids 3. Geochemistry
159	**04.01.00.00.**	Geology	Geological features of the geosphere, which comprises of the reservoir, overburden and surrounding rock prior to injection of CO2.	An understanding of the natural system into which the carbon dioxide is injected is essential for the assessment of long-term performance and safety.
160	**04.01.01.00.**	Geographical location	The geographic location of a CO2 storage reservoir will influence the type of impacts to consider, e.g. continental or sub-marine, in the vicinity of a volcano, or tectonic activity, etc. In addition, proximity to human populations will increase importance of any release to the surface. 1. Onshore reservoir 2. Offshore reservoir 3. Near volcanic or tectonic activity 4. In densely populated areas	Proximity to natural hazards will increase their importance in being considered in the assessment. Proximity to human populations place more emphasis on the significance of near-surface releases. The potential impact on human beings of a sudden release of CO2 from an onshore reservoir will be higher than from an onshore reservoir (Damen 2006) The potential impact on human beings of a sudden release of CO2 from an offshore reservoir will be lower than from an onshore reservoir (Damen 2006). However CO2 storage costs are likely to be higher for offshore reservoirs.

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161	**04.01.02.00.**	Natural resources	Natural resources within the geosphere including: solid mineralogical resources, such as coal or minerals, fluid and gaseous resources, such as hydrocarbons (EOR and ECBM) or water, and other resources such as geothermal or microbial resources. Deep aquifers with high porosity suitable for CO2 storage would also be potentially suitable for geothermal energy production. (CO2STORE, page 70) Rights to pore space normally stay with the owner of the surface land. However, this may vary from state to state. Although saline water has few uses currently, these resources are protected by mining law in some EU states. And in some countries and states, brines legally are classified as groundwater and protected by law, (CO2STORE page 70). Depths for known natural major CO2 fields range from 200 to 5,000 m (656 to 16404 ft). (CCP 2009) 1. Mineral resources 2. Coal seams 3. Oil resources 4. Natural gas resources 5. Underground drinking water sources	The presence of natural resources may mean that future human exploitation of the system cannot be ignored in assessing long-term performance since they may increase the possibility of future human intrusion. Owners of mineral rights could claim primacy over CO2 injection. Unmineable coal seams could become mineable with robotic mining systems. There may be adjacent oil properties owned by third-parties that could be contaminated by CO2 injection. Natural gas could be released when drilling and injecting CO2. CO2 mixed with natural gas would need to be captured and reinjected. Underground drinking water could be contaminated by CO2 or displaced brine. CO2 combined with water could lead to corrosion of geothermal systems. CO2 from adjacent injection projects could infringe the project's pore space.
162	**04.01.03.00.**	Reservoir type	The generic type of reservoir being considered for storage of CO2. Brownfield developments, for example in mature oil and gas fields, will offer the benefit of beginning with a well-characterized system and a significant amount of infrastructure. However, field redevelopments for CO2 storage will require a significant amount of work to assess the integrity and re-usability of existing well, flow lines and facilities. (CCP 2009) Greenfield developments, such as deep saline aquifers, require significant new infrastructure and additional initial characterization work and are associated with greater uncertainty. A steeper learning curve is to be expected and modifications to an initial development plan may occur as additional knowledge is gained during early development work. (CCP 2009) 1. Oil reservoir - EOR (such as the Weyburn project); 2. Gas reservoir (such as the Coal-Seq project); 3. Deep saline aquifer (such as at Sleipner); and 4. Coal seams - ECBM (such as the Coal-Seq and RECOPOL projects).	The generic reservoir type will provide a high-level indication of the geological characteristics of the storage location. It will also contribute towards the extent and type of historical exploitation of any geological resources. Development of brownfield sites can expect to include a significant number of well re-completions, abandonments and possibly re-abandonment of old wells, new drilling and upgrades to surface infrastructure. (CCP 2009) Greenfield sites require more time and money to develop sufficient site characterization data but are less likely to have leakage through existing wells due to the lack of existing wells.
163	**04.01.04.00.**	Reservoir geometry	Geometry of the CO2 storage reservoir including the spatial distribution, depth and the topography of the top.	The geometry of the storage reservoir helps to determine the capacity of the geosphere. The geometry of the top is particularly important because supercritical CO2 is buoyant and will therefore migrate to the top of a reservoir. Once at the top of the reservoir, it will migrate according to the precise topography of the top. Local “highs” could produce small-scale traps within the overall aquifer; bigger structures would produce bigger traps. Spill points are determined by the lowest point that can retain the sequestered CO2.

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164	**04.01.04.01.**	Reservoir depth (Reservoir hydrostatic pressure)	The hydrostatic pressure varies with depth. It is desirable to store CO2 at depths greater than approximately 800-1000 m where the hydrostatic pressure will maintain CO2 in a supercritical (dense) phase. (CCP 2009). Excessive depth will result in excessive hydrostatic pressure, which will require higher CO2 injection pressure. 1. Insufficient reservoir depth 2. Insufficient hydrostatic pressure 3. Excessive reservoir depth 4. Excessive hydrostatic pressure	Insufficient reservoir depth may result in pressures that are too low for keeping CO2 in a supercritical state. Excessive depth will require higher CO2 injection pressure and increase cost of CO2 injection..
165	**04.01.04.02.**	Reservoir thickness	Normally, a formation thickness of around 20 m (66 ft) would be considered as a minimum requirement, but this varies with injection volume requirements. 1. Insufficient reservoir thickness	Insufficient reservoir thickness will result in an extended CO2 plume and limit the storage capacity of the reservoir
166	**04.01.04.03.**	Reservoir lateral continuity (spatial distribution)	Lateral flow barriers can include unconformities or pinch-outs that erode the porous and permeable material and provide direct contact to a low permeability seal, faults and naturally over pressured zones. 1. Insufficient reservoir lateral continuity	Insufficient lateral continuity (or spatial distribution) of a reservoir will limit its CO2 storage capacity
167	**04.01.04.04.**	Reservoir top topography	Reservoirs with dipping top topography (monocline) are susceptible to buoyancy-driven up dip CO2 migration. The migration up dip may enhance CO2/brine contact and CO2 dissolution in the brine. The preferred top topography is an anticline or dome structure to restrict the flow of injected CO2 on multiple sides. Spill point is the lowest point that can retain sequestered CO2. 1. Flat 2. Monocline 3. Dome	Flat top topography of the reservoir may make it difficult to contain the CO2 plume Dipping top topography of the reservoir may make it difficult to trap buoyant CO2. Injected CO2 migrates up dip out of closure. Shallow spill point in a dome structure may limit the amount of CO2 that can be locally contained in a reservoir
168	**04.01.04.05.**	Reservoir buffer zone for CO2 plume	The buffer zone represents additional land owned or leased beyond the ultimate extent of the CO2 plume. 1.Insufficient buffer zone for CO2 plume	Insufficient buffer zone may result in CO2 plume infringing on third-party pore space.
169	**04.01.04.06.**	Reservoir CO2 storage capacity	Reservoir CO2 storage capacity is primarily determined by pore volume. 1. Insufficient reservoir storage capacity.	Insufficient reservoir storage capacity will require alternative storage site(s). Increased storage costs.
170	**04.01.04.07.**	Reservoir lateral sealing	Lateral flow barriers can include unconformities or pinch-outs that erode the porous and permeable material and provide direct contact to a low permeability seal, faults and naturally over pressured zones. 1. Open reservoir (lack of lateral sealing of reservoir) 2. Closed reservoir 3. Semi-closed reservoir	Potential for CO2 plume to infringe on third-party pore space or escape if lateral seal is lacking.
171	**04.01.04.08.**	Reservoir and caprock structural geology complexity	In tectonically complex areas, there are too many small structures to be identified, delineated and investigated individually. 1. Reservoir and caprock structural geology too complex	Complex structural geology may result in greater difficulty in modeling, monitoring and controlling CO2 storage.

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172	**04.01.04.09.**	Reservoir compartmentalization	A once continuous reservoir can become compartmentalized. CO2 migration restricted to an isolated part of the formation. Unexpected bottom hole pressure increase. Pressure transient analysis suggests hydraulically isolated wells.	Greater difficulty in modeling, monitoring and controlling CO2 storage.
173	**04.01.04.10.**	Reservoir temperature **(See 04.01.13.00.)**		
174	**04.01.04.11**	Reservoir rock thermal properties	Rock thermal properties included: 1. Thermal conductivity 2. Heat capacity 3. Thermal expansion coefficient	These properties will dictate how fast the rock will change temperature in response to injected CO2 that is warmer or cooler than the reservoir, and they will also dictate whether fracture or pore permeability will increase or decrease as a result of temperature changes in the rock mass.
175	**04.01.05.00.**	Reservoir exploitation	Degree to which geological resources (such as oil and gas) have been exploited prior to the injection of CO2. 1. Existing boreholes 2. Oil previously removed 3. Gas previously removed 4. Existing mine workings (for ECBM) 5. In-situ gasification (for ECBM) 6. Natural gas storage 7. Compressed air storage 8. Radioactive waste storage 9. Hazardous waste disposal (Class 1 wells) 10. Water extracted	The extent of previous exploitation will help to determine the initial state of a storage reservoir. For example: - the existence and nature of boreholes; and - the presence of geological resources, such as oil and gas. Previous exploitation of the storage reservoir area will improve the amount of historical information available concerning the reservoir characteristics.
176	**04.01.06.00.**	Caprock or sealing formation	The nature of the relatively impermeable layer of rock overlying the storage reservoir that forms a barrier to the upward migration of buoyant fluids, such as sequestered CO2.	The caprock or sealing formation plays a key roll in preventing the sequestered CO2 from migrating to the surface environment.
177	**04.01.06.01.**	Caprock geometry	Geometry of the caprock including the spatial distribution, depth and the topography of the bottom.	CO2 migration diverges from expected path. Significant CO2 volumes migrate off structure. Insufficient capacity for planned injection volume of CO2. Unexpected pressure increase during injection.

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178	**04.01.06.02.**	Caprock thickness	Greater thickness improves the strength and sealing capacity of the caprock. Preferred caprock thickness:> 100m Minimum caprock thickness: >20m	Insufficient caprock thickness could lead to caprock failure and/or release of CO2 from the reservoir.
179	**04.01.06.03.**	Caprock discontinuous	Caprock discontinuities can be caused by unconformities or pinchouts.	CO2 escapes through gap in caprock into higher formation or aquifer
180	**04.01.06.04.**	Caprock geochemical properties	CO2 chemical reaction with caprock can weaken the physical strength of the caprock. High permeability zones might exist or be formed by reaction of CO2 with the caprock, causing the caprock to dissolve. CO2 can dehydrate clay shales in the caprock, thereby increasing its permeability. (Damen 2006)	Unintended migration of CO2 by chemical reaction induced breaching of the caprock.
181	**04.01.06.05.**	Caprock geomechanical properties	Low fracturing pressure	Could limit CO2 injection rate. Increased CO2 injection cost. In general, the mechanical behavior of shale will show more elastic change and is more resistant to elevated pressure than other brittle hard rock.
182	**04.01.06.06.**	Caprock permeability	The permeability of a caprock capable of retaining fluids through geologic time is approximately 0.001 to 0.00001 milli-darcies (mD). Mudstone caprock permeability is typically less than 0.001 mD.	Permeable zones in the caprock could form CO2 pathways of escape.
183	**04.01.06.07.**	Caprock capillary entry pressure	No rocks have zero porosity, but the sealing layer provides a seal because the pore throats are too small to permit CO2 to enter the water-filled pores. (CCP 2009)	If the CO2 injection pressure exceeds the capillary pressure of the caprock, CO2 can penetrate or pass through the caprock
184	**04.01.06.08.**	Caprock fracture pressure	The critical pressure to avoid exceeding is the fracture pressure of the confining interval (caprock) above the reservoir, which is normally higher than the fracture pressure in the injection interval. (CCP 2009) Maximum injection pressure is typically at least 0.34 MPa (50 psi) below fracture pressure. EPA UIC Class VI regulations limit CO2 injection pressure to 90 percent of facture pressure.	If the CO2 injection pressure exceeds the fracture pressure of the caprock, the caprock could fracture and allow CO2 to pass through the caprock.
185	**04.01.07.00.**	Additional seals and sinks (secondary seals)	This concerns the concept of successive lithological, hydraulic and/or chemical barriers acting successively to prevent fluid escape to surface environments. From a geological point of view the permeability barrier is probably the most important, in comparison with other types of traps. However, it may be necessary to consider a sequence of traps in CO2 migration models in addition to the conventional low permeability barriers. For example, within the Weyburn sequestration project, the primary caprock is the Watrous formation, however, low permeability formations at higher stratigraphical layers provide potential additional seals, preventing upward migration of sequestered CO2. Stacked reservoirs consist of multiple alternating seals and reservoirs above the primary reservoir. The additional reservoirs can provide a back up for CO2 containment if the primary seal is broken. 1. Multiple stacked seals	Without multiple stacked seals and sinks there is no fallback position if CO2 escapes through the primary seal.

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186	**04.01.08.00.**	Lithology	The systematic description of rocks in terms of their mineral assemblage and texture. The lithology of the geosphere (including both the reservoir and the caprock) determines the reservoir physical and transport properties (including porosity and permeability). It concerns the mineralogical composition, texture (grain size, sorting) and fabric (sedimentary structures, vertical and horizontal heterogeneities). Potential reservoir lithologies include sandstones and limestones. 1. Caprock lithology 2. Reservoir lithology	The physical and chemical and mineralogical properties of the reservoir rocks affect: the capacity to store CO2; fluid flow and CO2 migration; determine which water-rock reactions can take place; and influence the rock strength and elastic properties (such as compressibility, shear strength, Poisson's ratio etc).
187	**04.01.08.01.**	Lithification / diagenesis	The slow physical, chemical and/or biological processes by which unconsolidated sediments become sedimentary rock. These processes can result in changes to the original mineralogy.	The state of lithification/diagenesis contributes to determining the physical and chemical characteristics of sedimentary rock. For example, porosity usually decreases during diagenesis, except in rare cases such as dissolution of minerals and dolomitization. It is very unlikely that deep subsurface geologic formations are unconsolidated. Unconsolidated formations are young in geologic time and located at shallow depths.
188	**04.01.08.02.**	Pore architecture **(See 04.01.08.03. and 04.01.08.04.)**	Structure and density of discrete voids within the rock (pores). 1. Reduced pore volume or distribution limiting CO2 injection	The pore architecture determines the porosity and permeability of the rock, which are key features when considering the mobility of fluids and gases within the rock. Rate of long-term pressure build-up greater than expected. Increases CO2 injection cost. Need for additional wells. In EOR, pore architecture impacts sweep efficiency and oil recovery.
189	**04.01.08.03.**	Reservoir porosity	Porosity values greater than 10% in carbonate formations or 15% in clastic formations are generally desirable. (CCP 2009). It is important to distinguish between total porosity and effective (flowing) porosity. Flowing porosity is what can be readily displaced by CO2 invasion. Total porosity minus flowing porosity is pore space that will likely remain occupied by residual pore fluids after CO2 invasion, although CO2 can diffuse into this pore space. 1. Total porosity 2. Effective (flowing) porosity	Low porosity makes CO2 injection more difficult and can limit the rate of injection into a reservoir. In EOR, porosity impacts oil in place and oil recovery.

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190	**04.01.08.04.**	Reservoir permeability and injectivity	Permeability measures the ability of fluids to flow through a formation. High values indicate a well-connected pore space while low values indicate convoluted conduits that disconnect the pores. Porous rocks have a wide range in permeability between around 0.1 milli-Darcy (mD) for very tight rocks, to several darcies for very permeable formations. (CCP 2009) In general, the better the porosity, the better the permeability (and thus injectivity) - however, large variations in permeability mean the porosity and permeability variations need to be mapped in detail (CCP 2009) Ideally, CO2 storage requires high permeability (>100 mD) to ensure near well bore injectivities for quick access to pore space. However, this is not always possible and near wellbore permeabilities may need to be enhanced by artificially stimulating the wells to allow for improved injectivity. (CCP 2009) Injectivity is impacted by porosity and permeability. Low injectivity can be partially compensated for by greater injection pressure and/or more wells. Decreasing injectivity can result when initial injection rate	Low permeability makes CO2 injection more difficult and can limit the rate of injection into a reservoir. While high permeabilities are generally desirable, very high permeability pathways or conduits can enhance CO2 migration along concentrated pathways reducing the effective storage within the target formation. (CCP 2009) In moderate to low permeability, or poorly connected reservoirs, a higher well density will be needed to limit pressure evolution and allow for efficient injection. (CCP 2009) Uncertainty in permeability could lead to high numbers of wells needed. Low reservoir injectivity will limit the rate of CO2 injection and require increased bottom hole pressure and/or more injection wells. In EOR, permeability impacts sweep efficiency and oil recovery.
191	**04.01.09.00.**	Unconformities	Geological surfaces separating older from younger rocks and representing a gap in the geologic record. Such a surface might result from a hiatus in deposition of sediments, possibly in combination with erosion, or deformation such as faulting. An angular unconformity separates younger strata from eroded, dipping older strata. A disconformity represents a time of no deposition, possibly combined with erosion, and can be difficult to distinguish within a series of parallel strata. A nonconformity separates overlying strata from eroded, older igneous or metamorphic rocks. 1. Unconformities 2. Disconformities 3. Nonconformities	Unconformities can act both as potential seals or lateral migration pathways for fluids. For example, the impermeable barrier resulting from the widespread development of diagenic anhydritized carbonate associated with the unconformity between the Mississippian beds and overlying Triassic Watrous Formation in the vicinity of the Weyburn pool.
192	**04.01.10.00.**	Heterogeneities **(See 03.02.03.06.)**	Heterogeneities are variations in the rock properties of a geological formation. 1. Reservoir heterogeneity 2. High permeability layers in reservoir 3. Interstitial layers of shale or baffles in reservoir 4. Caprock heterogeneity (high permeability zones) 5. Heterogeneity of overlying aquifers (more difficult to monitor for CO2) 6. Heterogeneity of porosity 7> Heterogeneity of mineralogy 8. Heterogeneity of degree of fracturing 9. Heterogeneity of geochemistry	Heterogeneities can result in directional variations in permeability, which affects the mobility of fluids and gases in the rock. For example, experience from the Saline Aquifer CO2 Storage project (SACS) has shown that both stratigraphical and structural local permeability heterogeneities have the potential to profoundly affect CO2 distribution and migration (Chadwick et al., 2003). The image below shows seismic sections through the Sleipner injection site from Zweigel et al. (2001). The strong amplitudes are taken to be CO2 accumulations.

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193	**04.01.11.00.**	Fractures and faults (CO2 leakage through new or existing fractures or faults)	Fractures are cracks or breaks in rock. Fractures along which displacement has occurred are called faults. Fractures and faults can occur over a wide range of scales. The presence of a fault does not imply a leakage problem. Most rocks are faulted and fractured in some way over geological time. The critical question for CO2 storage is whether there are any faults or fractures that could provide leakage pathways under present day geological conditions. In addition to the basic geometry of connected rocks and flow paths, this involves the study of geomechanics, stress fields and fracture behavior. Simply put many "faults: do not leak at all and many huge oil and gas fields that include faults prove the point. (CCP 2009)	Fractures can enhance conductivity, for example, by a conductive fracture connecting permeable regions together. They can also act as seals, by bringing a relatively permeable region into contact with low conductivity rock, for example. Movement on a fault that transverses a wellbore could damage or sever casing or tubing. CO2 might leak through open (no-sealing) faults, which extend into the caprock. CO2 might leak through natural fractures in the caprock.
194	**04.01.12.00.**	Undetected features	Natural or man-made features within the geological environment that may not be detected during site investigations. Examples of possible undetected features are fracture/fault zones, the presence of brines or old mine workings. Some physical features of the storage environment may remain undetected during site surveys and even during preliminary borehole drilling. The nature of the geological environment will indicate the likelihood that certain types of undetected features may be present and the site investigation may be able to place bounds on the maximum size or minimum proximity to such features. 1. Existing fracture/fault zones 2. Underground cavities/karsts (natural or man made) 3. Existing boreholes 4. Subsurface infrastructure (piping, underground utilities) 4. Gas chimneys 5. Shallow gas/drift gas (above bedrock) 6. Clustered small gas-related amplitude anomalies along fault planes	Undetected features could significantly affect the performance of a sequestration system. For example, local permeability heterogeneities with the potential to profoundly affect the distribution and migration of CO2 at Sleipner (within the Saline Aquifer CO2 Storage project, SACS) were only discovered after effectively being illuminated by the sequestered CO2 (Chadwick et al., 2003). Shallow gas (above bedrock) can cause drilling problems and impede monitoring.
195	**04.01.13.00.**	Vertical geothermal gradient **04.01.04.10.**	Temperature profile in the geosphere prior to the injection of CO2. Temperature generally increases with depth, but the rate of increase varies significantly depending on the geothermal gradient. The critical temperature for CO2 is 31.1°C. The average geothermal gradient is approximately 25°C per km. If the surface temperature is 10°C, the critical temperature will be reached at a depth of 840 m. However, a considerable variation in geothermal gradients and sub-surface temperatures can be expected at a depth of 1000 m. For example, in Europe temperatures at 1000 m range from 20 to 75°C, with local temperatures of more than 200°C in volcanic areas.	Relevant to temperature dependent physical/chemical/biological/hydraulic processes, such as CO2 phase behavior. Temperature, coupled with pressure, will affect the phase behavior of CO2 as well as the solubility of many other constituents present in the reservoir (including gases, liquids and solids.)

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196	**04.01.14.00.**	Formation pressure	The pressure of fluids within the pores of a formation, normally hydrostatic pressure, or the pressure exerted by a column of water from the formations depth to the sea level prior to the injection of CO2. The critical pressure of CO2 is 7.38 MPa. The average underground hydrostatic pressure increases with depth by approximately 10.5 MPa per km for aquifers that are in open communication with surface water. Applying this average gradient, the critical pressure of CO2 will be reached at a depth of around 690 m. However, aquifers or hydrocarbon reservoirs (e.g., EOR and ECBM) that are sealed off from the rest of the sub-surface may be under- or over pressured. 1. Hydrostatic pressure 2. Fracture pressure 3. Lithostatic pressure	Contributes towards determining the mobility of sequestered CO2.
197	**04.01.15.00.**	Initial stress and mechanical properties	The stress condition and mechanical properties of the geosphere prior to injection of CO2.	The initial stress state and mechanical properties are a baseline from which the potential effect of injecting supercritical CO2 can be assessed.
198	**04.01.16.00.**	Petrophysical properties **(See 03.02.03.01.; 04.01.08.03. and 04.01.08.04.)**	Petrophysical properties of the geosphere prior to the injection of CO2. This includes features such as permeability, porosity, residual saturation, capillary pressure and wettability.	Petrophysical properties influence how injected CO2 will migrate in the geosphere. For example, permeability influences the direction and rate of CO2 movement, and porosity and residual saturation influence the dimensions of the CO2 plume.
199	**04.02.00.00.**	Fluids	Details of fluids in the geosphere, which comprises of the reservoir, overburden and surrounding rock prior to the injection of CO2. Water will generally be present, but other fluids, particularly hydrocarbons (e.g., EOR and ECBM), may be important, dependent on the sequestration concept.	Water and other fluids in the sequestration system will affect the transport and interactions of injected carbon dioxide.
200	**04.02.01.00.**	Fluid properties **(See 03.02.13.03)**	Properties of the geosphere fluids prior to injection of CO2, including composition and geochemistry. The high salinity of deep aquifers is, generally, an indication of very low or insignificant throughput of meteoric waters. 1. Fluid chemical composition and geochemistry 2. High salinity fluid 3. Fluid density	The fluid properties and geochemistry of the geosphere will contribute towards determining how injected CO2 will behave in the geosphere. Very high salinity can lead to deposition of halite in pore spaces and cause decreased permeability and injectivity.
201	**04.02.02.00.**	Hydrogeology	Natural formation water flow pathways (directions, velocities) in the geosphere will be important in determining the long-term migration paths for CO2. This depends on factors including: hydraulic heads, permeability and porosity distribution, the existence of fracture networks, connection between aquifers, position of the recharge and discharge areas. 1. Natural fluid flow pathways 2. Position of aquifer recharge and discharge areas 3. Connection between deep saline aquifer and shallow drinking water aquifer	This will affect the migration of dissolved CO2 in the reservoir and the geosphere (direction, timing), the position of the interface between supercritical CO2 and aquifer water (inclined interface). There may also be a possible effect on overlying aquifers used for drinking water.

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202	**04.02.03.00.**	Hydrocarbons	The presence and distribution of hydrocarbons, such as oil and/or gas (e.g., EOR and ECBM), within the storage system.	Hydrocarbons have potentially important implications for a storage system, by both influencing the likelihood of previous geological exploitation of the area, and by being an important component of the system with which sequestered CO2 can interact.
203	**05.00.00.00.**	**BOREHOLES**	This category of FEPs is concerned with the way that activity by humans alters the natural system. Both boreholes used in the sequestration operations and those drilled for other purposes are relevant to the long-term performance of the system. The category is divided into two classes for the drilling process, and sealing and abandonment.	This category is divided into two classes: 1. Drilling and completion 2. Sealing and abandonment
204	**05.01.00.00.**	Drilling and completion	FEPs relevant to the operation of boreholes drilled within the system domain.	Boreholes can potentially provide short circuits for carbon dioxide transport.
205	**05.01.01.00.**	Formation damage (CO2 leakage through damaged caprock near borehole)	Alteration of the far-field or virgin characteristics of a formation, usually by exposure to drilling fluids. Fracturing associated with formation damage can increase porosity, whereas the water or solid particles in the drilling fluids, or both, can decrease the pore volume and effective permeability of the formation in the near-wellbore region. Some boreholes in the early 20th century may have been explosive fractured with nitroglycerin. Later boreholes may have been hydrofractured. 1. Explosive fracturing 2. Hydrofracturing A number of mechanisms can result in a decrease in porosity, including: 3. Solid particles from the drilling fluid physically plug or bridge across flow paths in the porous formation 4. Water from drilling causing clay minerals in the formation to swells 5. Chemical reactions between drilling fluid and the	Formation damage has a number of potential implications for assessing CO2 sequestration: - it can make information from affected boreholes non-representative of the true characteristics of the damaged formations; and - damaged regions themselves may provide flow paths for CO2 migration, particularly if damage results in fracturing. - decrease in near borehole porosity can result in unexpected increase in bottom hole pressure
206	**05.01.02.00.**	Well lining and completion	At the time of drilling, boreholes are lined with a metal casing. Cement is pumped downhole inside the casing string, and it is pushed upward under and outside the casing lower end, between the casing and the rock wall. In multi-stage cement jobs, cement is squeezed between the casing and the rock wall though purpose made perforations. The cement could be pushed behind casing from the bottom hole to the surface, or to a predetermined depth. Curing of cement is the process of maintaining the proper temperature and moisture conditions to promote optimum cement hydration immediately after placement. Proper moisture conditions are critical because water is necessary for the hydration of cementitious materials. As cement hydrates, strength increases and permeability decreases. When hydration stops, strength gain ceases. Therefore, proper hydration of the cement is important in the fabrication of strong, durable concrete. Alteration of borehole linings will occur with time, depending on the natural fluid composition of the deep reservoir and the input of high concentrations of CO2 carrying natural H2S, which may accelerate corrosion.	Borehole lining and completion will contribute to determining the performance of a borehole both during its operational and post-closure phases. This is important from the perspective of CO2 sequestration, since boreholes may provide preferential short circuits to the surface with potential release of CO2 and contamination of upper aquifers.

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207	**05.01.03.00.**	Workover	The process of performing major maintenance or remedial treatments on a borehole often associated with the re-use of existing boreholes. Workover techniques include flushing of the formation and the removal and replacement of the borehole lining. Well control procedures during workovers must provide for unique phase behavior of any CO2 being circulated out. (CCP 2009) EOR operations often re-complete old wells. Proper re-completion includes: Examining cement bond logs to evaluate bonding between the casing and adjoining formation. Use of squeeze cement if insufficient or inadequate bonding was detected. Wellbore drilling of plugged and abandoned wells to bottom of target formation. Run a casing mechanical integrity test. If pressure fall off was observed, the leaking section of casing should be identified and resealed by squeeze cementing or, in extreme cases, install a liner over the leaking section.	Workover will result in modified borehole properties that may need consideration within an assessment.
208	**05.01.04.00.**	Number and location of monitoring wells	Often, monitoring wells (observation wells or verification wells) are needed to monitor the physical conditions (pressure, temperature, etc.) of the storage reservoir, both inside and/or outside the area immediately affected by the storage operations, or above the storage reservoir. Monitoring wells could be “adopted”, by using existing wells to host the appropriate instrumentation (piezometers, pressure gauges, thermometers, etc.), or they could be purpose drilled anew. Direct monitoring techniques usually require access from wellbores that penetrate the containment system into the storage reservoir (CCP 2009) Direct measurements can also be obtained from observation wells at shallower horizons above the expected seal. Wells of this type might provide direct and early indication of unexpected movement. (CCP 2009) General the concept is to minimize monitoring wells that penetrate the seal because they are, by default, potential leakage pathways. (CCP 2009) 1. Lack of or insufficient number of monitoring wells 2. Too many monitoring wells 3. Improperly located monitoring wells.	Observation or monitoring wells may provide an accidental leakage route for the stored CO2, particularly wells drilled inside the area of storage. There are unique tradeoffs associated with the number and location of monitoring wells.
209	**05.01.05.00.**	Well records	The drilling of boreholes for site investigation, resource exploitation and/or CO2 injection will result in many documents being generated in paper or digital form. Typical well records include location co-ordinates, depth, electric logs, mud logs, drilling parameter logs, composite log, testing reports (if applicable), coring report (if applicable), and a final report. Physical records from cutting samples, cores and fluid samples will also be documented. The principal tool to gain knowledge about the sequence of drilled rock formations is Borehole Logging. Common measures include hole diameter, natural gamma ray response, spontaneous electrical potential, rock resistivity, velocity of acoustic waves through rock, neutron susceptibility, etc. The documents originating at the time of drilling are often the most accurate records of the succession of events associated with the drilling of the well. The curation of such unique records is an invaluable tool to pass knowledge to future generations. 1. Lack of or incomplete records for existing wells 2. Retention/management of well records and data	Well records provide a key source of baseline information regarding the sequestration site. They provide information concerning the nature of the rocks drilled by the well and their petrophysical characteristics in terms of sealing potential and reservoir potential. Additionally, records from wells drilled over a period of time can give a picture of how the system is evolving either naturally, or as a result of the exploitation of geological resources. This baseline information is an important input both into the initial conditions relevant to the system to be assessed, as well as providing an indication of the likely importance of other FEPs. Incomplete well records equate to a potential gap in understanding of the storage system and may result in potentially important features being overlooked in the assessment process. Large amounts of data will be generated by the project. Data could be poorly communicated between groups, or be badly managed to the point that important data is lost, or used incorrectly.

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210	**05.02.00.00.**	Borehole seals and abandonment	FEPs relevant to the closure of boreholes drilled within the system domain.	The way that boreholes are closed and sealed is directly relevant to the likelihood that they could act as short circuits for carbon dioxide transport.
211	**05.02.01.00.**	Closure and sealing of boreholes	Features related to the cessation of CO_2 injection operations at a site and the sealing of injection and monitoring wells. When a borehole is drilled to the potential storage reservoir, it creates communication with possible overlying reservoirs and with the surface. Cementing and abandonment procedures are designed to permanently plug such communication channel. The cement plugs are commonly located across potential problem spots, to minimize leaking risks. Particular attention should be paid to the quality of the original cement job behind the casing string. If uncemented space is detected, known or suspected behind casing, depending on the lithology across such interval, it may be important to squeeze extra cement between the rock face and the casing to complement the final abandonment plugs inside the casing. Individual boreholes may be closed in sequence, but closure refers to final closure of the whole system, and may include removal of surface installations. The schedule and procedure for sealing and closure may need to be considered in the assessment. A typical well abandonment may include the following: - Remove tubing and packer - Permanently seal the formation with a fluid that reduces permeability	The intention of borehole sealing is to prevent human access to the sequestered CO_2 and to prevent the borehole from providing a migration pathway for the CO_2. Correct cementing and abandonment operations are essential to achieve restoration of pristine sealing above the designed storage reservoir formation.
212	**05.02.02.00.**	Seal failure	Degradation of borehole linings (metal and cement) will occur with time, depending on the natural fluid composition of the deep reservoir and the input of high concentrations of CO_2. Any H_2S present may accelerate corrosion of metal linings. Cement will be attacked by high partial pressures of CO_2, low pH and appreciable concentrations of sulfate, chloride, and magnesium ions in the formation fluids. Seal failure will occur once liners have degraded and corroded. Portland cement blended with 50% fly ash had a 30 year life in a field that produced 96% CO_2 with water saturation of approximately 20%. (CCP 2009). Conventional Portland cement-fly ash systems can inhibit CO_2 migration even after carbonation of the cement because permeability remains relatively low and capillary resistance is relatively high. (CCP 2009). The Basis of Design for new wells should emphasize barrier performance using fundamentals of wellbore preparation, mud removal and cement placement to provide tight interfaces that inhibit fluid migration. Material selection of cement and metallurgy are important, but should be considered secondary to the process of cement placement. (CCP 2009). The cement interfaces between the boreholes and the casing through the caprock are the key to well integrity and seal integrity. Good isolation requires tight cement interfaces with the formation and casing. (CCP 2009)	Seal failure may provide preferential short circuits to the surface with potential release of CO_2 and associated contaminants to the surface or near-surface environment. The failure may provide a preferential pathway either through the borehole annulus or around the outside of the casing. Cement interfaces, not cement matrix are the most likely path for migration. (CCP 2009). 1. CO_2 leakage at cement-casing interface 2. CO_2 leakage through the cement matrix 3. CO_2 leakage through pathways created by chemical dissolution of cement 4. CO_2 leakage through fractures in cement 5. CO_2 leakage through an open annular region due to inadequate cement placement 6. CO_2 leakage at cement caprock interface 7. CO_2 leakage through corroded or cracked casing 8. CO_2 leakage through packer

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213	**05.02.03.00.**	Blowouts	Uncontrolled flow (CO2, brine, oil, gas or mixture of these) from depth leading to gas and/or fluid erupting from a well or borehole to either the terrestrial or aquatic environments. Blowout is an ordinary drilling hazard, well understood and controlled by current technology. Assuming that ordinary blow-out risk controls are present, particular risks might include: (1) A monitoring or verification well drilled into a porous formation that has elevated pressure due to CO2, or (2) A drilled formation with significant unexpected H2S (MCSG 2009). The greatest danger for loss of well control is during workover operations. Estimates based on both oil and gas wells give a frequency of $3x10^{-4}$ blowouts per well per year (IEA GHG, 2003) (Damen 2006). 1. Blowout due to equipment failure (packer, blowout preventer, valve failure) 2. Blowout due to accident (truck backing over injection well) 3. Blowout due to human error (valve left open) 4. Blowout of CO2 injection well 5. Blow out of production well	A surface or undersea blowout would provide a rapid pathway for CO2 to reach the surface. Apart from the CO2 release, the potential consequences are casualties among operators and economic damage caused by explosion or fire when upcoming hydrocarbons are ignited or by parts of the well, which can be launched by the pressure release.(Damen 2006)
214	**05.02.04.00.**	Orphan wells	CO2 storage projects may be part of an Enhanced Oil Recovery (EOR) project or stand-alone deep saline aquifer projects. Either way, it is likely that the target geological structure has been the object of past exploration efforts, possibly involving drilling wells. The existence of old wells could be obvious if the wells are still active, but could be overlooked if the old (orphan) wells have been long cemented and abandoned. Technical details of such abandoned vintage wells may in fact not be readily available, or altogether lost. In such a case, the old cementing (sealing) job could be substandard. Some coal bed methane operations used open completion wells (no casing). It is possible to stabilize a hole without casing with gravel packing or sorted liners 1. Failure to identify and locate existing wells - active wells, abandoned wells, shallow wells that don't penetrate the caprock, deep wells that penetrate the caprock 2. Failure to test wells for mechanical integrity 3. Failure to remediate old wells 3. Failure of old well due to poor cementing, sealing, closing 4. Improper workover/recompletion of old well 5. Leakage of CO2 or brine through old well to overlying formations, underground aquifers or surface. 6. Collapse of open borehole (non-cased, open-completion holes often used in CBM)	Old substandard plugged well could provide a potential CO2 leakage route to the surface or to possible reservoirs above the designed CO2 storage reservoir. There is little chance of detecting a substandard well abandonment before the beginning of CO2 injection to the designed reservoir, particularly if the existence of an old well has been overlooked. If old abandoned wells are known in the area of the CO2 injection operations, the risk is minimized by carefully check any potential CO2 leak to the surface at the old well head location. If old wells are unknown and not suspected, it is good practice to run a baseline soil gas survey (if applicable) and successive soil gas surveys at intervals after the beginning of CO2 injection. Open completion wells are more likely to leak than other wells and subject to collapsing.
215	**05.02.05.00.**	Soil creep around boreholes	The slow downward gravitational movement of soil around boreholes.	This process results in changing properties of the soil around borehole casings after abandonment. It may either increase or decrease the degree of sealing and therefore the potential for the region immediately around the borehole to act as a migration pathway for CO2 and/or associated contaminants.

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216	**05.02.07.00.**	Borehole sand control (sand blocking)	Applies to unconsolidated reservoirs. Sand control may be necessary to maintain the structure of the reservoir around the wellbore. Migration of sand and fines into the near wellbore area may severely restrict production/injection. Sand blocking is a problem when the reservoir is unconsolidated and the wellbore is shut in for maintenance or upsets. (CCP 2009) Dehydration and deposition of gravel pack contents that cannot be displaced or removed from the well (CCP 2009) 1. Sand blocking 2. Dissolution of sand control resins 3. Dehydration and deposition of gravel pack contents	Operation delays. Maintenance costs.
217	**05.02.08.00.**	Wellbore fluids (causing corrosion or scale buildup)	Once the well is completed, impairment implications of the fluids or non-fluids left in the wellbore during startup will need to be considered. (CCP 2009) It is important to consider the displacement of any fluids into the reservoir during start up and the effect of injectivity resulting from the introduction of the fluids. (CCP 2009) Stimulation fluids should be carefully selected in terms of compatibility with the well materials, workover materials and reservoir. (CCP 2009) 1. Wellbore fluids 2. Startup fluids 3. Stimulation fluids	Fluids left in the wellbore for extended amounts of time could potentially corrode the tubulars, drop out precipitants, or cause bacterial growth. (CCP 2009) Startup fluids may impact injectivity due to precipitation of solids. Stimulation fluids may cause corrosion or precipitation of solids.
218	**06.00.00.00.**	**NEAR-SURFACE ENVIRONMENT**	This category of FEPs is concerned with factors that can be important if sequestered carbon dioxide returns to the accessible environment. The environment could be terrestrial or aquatic, and human behavior in that environment needs to be described. The category is divided into three classes: Terrestrial Environment; Aquatic Environment; and Human Behavior.	This category is divided into three classes: 1. Terrestrial environment 2. Aquatic environment 3. Human behavior
219	**06.01.00.00.**	Terrestrial environment	This class of FEPs is concerned with factors that can be important if sequestered carbon dioxide returns to the accessible terrestrial environment.	The near-surface environment is where most potential impacts would be incurred. The FEPs in this class are relevant if that environment is terrestrial.
220	**06.01.01.00.**	Topography and morphology	Features related to the relief and shape of the surface environment and its evolution. 1. Low surface areas (valleys, gullies, ditches) 2. Rugged terrain 3. Confined spaces (caves, canyons)	This FEP refers to local land form and land form changes with implications for the surface environment, e.g. plains, hills, valleys, and effects of river and glacial erosion thereon. In the long term, such changes may occur as a response to other geological changes. Leaked CO2 can accumulate in low surface areas and confined spaces. Rugged terrain may make it difficult to access the site, difficult to lay pipeline and difficult to monitor or conduct seismic studies.

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221	**06.01.02.00.**	Soils and sediments impact on project	Features related to the physical and chemical characteristics of the soils and sediments and their evolution. Different soil and sediment types, e.g. characterized by mineralogy, particle-size distribution and organic content, will have different properties with respect to erosion/deposition, sorption etc.	Soil and sediment characteristics will influence the type of vegetation and land use. They will also determine relevant processes to consider should CO2 and/or associated contaminants migrate to the terrestrial surface environment.
222	**06.01.03.00.**	Erosion and deposition	FEPs related to all the erosional and depositional processes that operate in the surface environment, and their evolution with time. Relevant processes may include fluvial and glacial erosion and deposition, denudation, Aeolian erosion and deposition. These processes will be controlled by factors such as the climate, vegetation, topography and geomorphology.	Erosional and depositional processes will influence the way in which the surface environment has evolved and will evolve over the time-scale of interest.
223	**06.01.04.00.**	Atmosphere and meteorology **(See 10.01.01)**	FEPs related to the characteristics of the atmosphere, weather and climate, and their evolution with time. In case of CO2 leakage to the surface, the weather is a relevant factor determining the dispersion or the displacement of the gas: currents, evolution of the concentration of the gas, gas accumulations. Atmospheric characteristics include physical transport of gas, aerosols and dust in the atmosphere and chemical and photochemical reactions. Meteorology is characterized by atmospheric precipitation, temperature, pressure, wind speed and direction. The variability in meteorology should be included so that extremes such as drought, flooding, storms and snow melt are identified.	This information will determine the behavior of CO2 should it reach the atmosphere and is therefore an important factor when considering exposure of the local population and of the local environment. Meteorological characteristics also influence the near-surface hydrological regime with its subsequent consequences for CO2 migration.
224	**06.01.05.00.**	Hydrological regime and water balance	Processes related to near-surface hydrology at a catchment scale and also soil water balance, and their evolution with time. The hydrological regime is a description of the movement of water through the surface and near-surface environment. It includes the movement of materials associated with the water such as gas or particulates and extremes such as drought, flooding, storms and snow melt. 1. CO2 and associated contaminants leakage affecting the hydrological regime and water balance. 2. Displaced brine affecting the hydrological regime and water balance 3. Groundwater withdrawal causing change in CO2 or brine migration 4. ECBM water extraction impacting water level in shallow	The hydrological regime and water balance will influence the way in which CO2 migrates should it reach the near-surface environment.
225	**06.01.06.00.**	Near-surface aquifers and surface water bodies	Features related to the physical and chemical characteristics of aquifers and water-bearing features and their evolution.	**Shallow Aquifers** Aquifers may yield significant amounts of water to wells or surface springs and may thus be a flow path for CO2 to the surface environment. The presence of aquifers and other water-bearing features will be determined by the geological, hydrological and climatic factors. Shallow aquifers will be able to dissolve CO2, reducing further upward migration. The amount of CO2 that can dissolve will depend on factors such as the location of the water table, the chemical composition of pore waters, CO2 flux rates, and hydrogeology. **Surface Water Bodies** Streams, rivers and lakes often act as boundaries of hydrogeological systems. They may represent a

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226	**06.01.07.00.**	Terrestrial flora and fauna	Features and processes related to the characteristics of terrestrial and freshwater flora and fauna, and their evolution. Includes plants, animals, fungi, algae and microbes. Plants usually have a higher resistance against CO2 than mammals, but persistent leaks could suppress respiration in the root zone. Tree kills associated with soil gas concentrations in the range of 20-30% have been observed at Mammoth Mountain, California, where volcanic out gassing of CO2 (0.13-0.44 Mt/yr) has been occurring since at least 1990. The leakage rate (flux) varies between 25 and 7000 g CO2/day/m2. (Damen 2006). 1. Natural flora and fauna 2. Agricultural flora and fauna	Flora and fauna may be affected by concentrations of CO2 in the near-surface environment and may be indicators of CO2 leakage.
227	**06.01.08.00.**	Terrestrial ecological systems **(See 06.01.07.00)**	Features and processes related to interactions between terrestrial and freshwater populations of animals, plants, algae, fungi, microbes and their evolution. Characteristics of the ecological system include the vegetation regime, and natural cycles such as forest fires or flash floods that influence the development of the ecology. The plant, animal, algal, fungal and microbial populations occupying the surface environment are an intrinsic component of its ecology. Their behavior and population dynamics are regulated by the wide range of processes that define the ecological system. Human activities have significantly altered the natural ecology of most environments.	The ecology of the terrestrial near-surface environment determines the types of organisms present and their inter-dependencies. These can influence the types of impact of interest and can provide a mechanism for monitoring CO2 leakage.
228	**06.02.00.00.**	Aquatic environment	This class of FEPs is concerned with factors that can be important if sequestered carbon dioxide returns to the accessible aquatic environment (seas, lakes, rivers).	The near-surface environment is where most potential impacts would be incurred. The FEPs in this class are relevant if that environment is aquatic.
229	**06.02.01.00.**	Coastal features	Features and processes related to the characteristics of coasts and the near shore, and their evolution. Coastal features include headlands, bays, beaches, spits, cliffs and estuaries.	The processes operating on these features, e.g. active erosion, deposition, longshore transport, may affect mechanisms for the migration of CO2, and associated contaminants, entering the surface environment.
230	**06.02.02.00.**	Local oceanography	Features and processes related to the characteristics of seas and oceans and their evolution. This includes the topography and morphology of the seabed; thermal stratification and salinity gradients; and marine currents.	The local oceanographic features and processes determine the potential for dilution or accumulation of CO2, or associated contaminants in the marine environment.
231	**06.02.03.00.**	Aquatic sediments	Features and processes associated with sediments in the aquatic environment. This includes both the physical and chemical characteristics of the sediments, along with sedimentation and resuspension processes.	Aquatic bed sediment characteristics will influence the ecology of the aquatic environment. They will also determine relevant processes to consider should CO2 and/or associated contaminants migrate to the aquatic environment.
232	**06.02.04.00.**	Aquatic flora and fauna	Features and processes related to the characteristics of aquatic flora and fauna, and their evolution. Includes plants, animals, fungi, algae and microbes.	Flora and fauna may be affected by concentrations of CO2 in the aquatic environment and may be indicators of CO2 leakage.
233	**06.02.05.00.**	Aquatic ecological systems	Features and processes related to interactions between populations of algae, animals, microbes and their evolution. Characteristics of the ecological system. The algal, animal and microbial populations occupying the aquatic environment are an intrinsic component of its ecology. Their behavior and population dynamics are regulated by the wide range of processes that define the ecological system.	The ecology of the aquatic environment determines the types of organisms present and their inter-dependencies. These can influence the types of impact of interest and can provide a mechanism for monitoring CO2 leakage.

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234	**06.03.00.00.**	Human behavior	Details of the human behavior in the near-surface environment where impacts may be incurred.	Human behavior will affect the nature and magnitude of potential impacts to human beings.
235	**06.03.01.00.**	Human characteristics	Features and processes related to characteristics, e.g. physiology, metabolism, of individual humans. This includes considerations of variability, in individual humans, of physiology and metabolism due to age and other variations. Physiology refers to body and organ form and function. Metabolism refers to the chemical and biochemical reactions which occur within an organism, or part of an organism, in connection with the production and use of energy. Children and infants, although similar to adults, often have characteristic differences, e.g. metabolism and respiratory rates, which may lead to different characteristics of exposure to CO2 or contaminants.	Human physiology and metabolism determine the effect of exposure to CO2 and associated contaminants.
236	**06.03.02.00.**	Diet and food processing	Features related to intake of food and water by individual humans and the compositions and origin of intake. This includes considerations of how diets, of individual humans, may vary with age and other variations (ingestion of soil by infants, for example). This FEP also includes processes related to the treatment of foodstuffs and water between origin and consumption. For example, once a crop is harvested it may be subject to a variety of storage, processing and preoperational activities prior to human or livestock consumption. Water sources may be treated prior to human or livestock consumption, e.g. chemical treatment and/or filtration.	The human diet provides a potentially important exposure pathway to contaminants released into the food chain as a result of the CO2 sequestration system. Food preparation processes may change the distribution and content of CO2 and/or associated contaminants in the product.
237	**06.03.03.00.**	Lifestyles	Features related to non-diet related behavior of individual humans, including time spent in various environments, pursuit of activities and uses of materials. This includes consideration of variability of the habits of individuals due to age and other factors. The human habits refer to the time spent in different environments in pursuit of different activities and other uses of materials. The diet and habits will be influenced by agricultural practices and human factors such as culture, religion, economics and technology.	Human habits will determine the exposure pathways of interest in an assessment. Camping, plowing, fishing, and swimming are examples of behavior that might give rise to extended close proximity exposure to CO2 and/or contaminants mobilized in an area of CO2 sequestration.
238	**06.03.04.00.**	Land and water use	FEPs related to land and water use by humans in the near-surface environment and the resulting implications for CO2 leakage and contaminant transport and exposure pathways. This includes consideration of: - the use of natural or semi-natural tracts of land and water such as forest, brush, rivers, lakes and the sea; - rural and agricultural land and water use (including freshwater and marine fisheries); - urban and industrial land and water use related to developments, including transport, and their effects on hydrology; and - leisure and other uses of environment.	These FEPs can influence the potential transport and exposure pathways for CO2 and its associated contaminants as well as the potential evolution of the system during the timescales of interest. Particular considerations are relevant for each type of land use addressed, for example: - special foodstuffs and resources may be gathered from natural land and water which may lead to significant modes of exposure to CO2 or contaminants; - an important set of processes are those related to agricultural practices, their effects on land form, hydrology and natural ecology, and also their impact in determining contaminant uptake through food chains and other exposure paths; - human populations are concentrated in urban areas in modern societies. Significant areas of land may be devoted to industrial activities. Water resources may be diverted over considerable distances to serve urban and/or industrial requirements; - significant areas of land, water, and coastal areas may be devoted to leisure activities. e.g. water bodies for recreational uses, mountains/wilderness areas for hiking and camping activities.

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239	**06.03.05.00.**	Community characteristics	Features related to characteristics, behavior and lifestyle of groups of humans that might be considered as target groups in an assessment. Relevant characteristics might be the size of a group and degree of self-sufficiency in food stuffs/diet. Associated with this is a consideration of the amount of resources required to meet the needs of the community.	This FEP involves a consideration of aggregated human behavior in order to consider their dependency on and interactions with their environment. It therefore provides input to a consideration of potential human interference with the CO2 storage system as well as input to considering potential exposure pathways.
240	**06.03.06.00.**	Buildings	Features related to houses, or other structures or shelters, in which humans spend time. 1. Basements/cellars 2. Subterranean pathways	The structure or materials used in building construction be significant factors for determining potential exposure pathways to CO2 or contaminants. For example, given that CO2 is denser than air, it may accumulate in the basements/cellars of dwellings.
241	**07.00.00.00.**	**IMPACTS**	This category of FEPs is concerned with any endpoint that could be of interest in an assessment of performance and safety. The classes of impact considered are: Impacts to Humans; Impacts to Flora and Fauna; and Impacts to the Physical Environment. Note that: - financial impacts are assumed to be implicitly considered within each of the impact FEPs; and - unless stated, the FEPs refer to both CO2 and mobilized contaminants (minerals, heavy metals, hydrocarbons (e.g., EOR and ECBM), gases).	This category is divided into four classes: 1. System performance 2. Impacts on the physical environment 3. Impacts on flora and fauna 4. Impacts on humans
242	**07.01.00.00.**	System performance	Performance of the sequestration system from the perspective of its success at preventing sequestered CO2 from reaching the atmosphere.	The fate of sequestered CO2 is a fundamental endpoint for an assessment.
243	**07.01.01.00.**	Loss of containment	Loss of sequestered CO2 from the intended storage reservoir. Loss includes both consideration of loss to other parts of the geosphere and to the near-surface and surface environments, such as loss to marine water and surface water bodies, where CO2 may result in stratification or pooling.	Loss of containment may be an endpoint of interest to the assessment. For example, the assessment context may dictate that near-surface or surface processes are outside the scope of the assessment.
244	**07.02.00.00.**	Impacts on the physical environment	FEPs relevant to adverse impacts on the physical environment. Note that these may be endpoints of interest in themselves, but may also cause other impacts of interest.	Adverse impacts on the environment can be postulated as a result of sequestration operations, even if there are no associated impacts to humans or on flora and fauna.
245	**07.02.01.00.**	Contamination of groundwater (and/or surface water)	The existence of water aquifers may be important if they are subject to CO2-induced chemical changes or CO2-induced saline intrusion. The migration of CO2 into an aquifer will result in the acidification of the water. Depending on the mineralogical composition of the aquifer and the chemical composition of the water, chemical reactions may occur which release heavy metals from the solid phase. The mechanisms which may cause this release include dissolution of metal oxides or oxyhydroxides, the reaction/diagenesis of clay minerals, and the desorption of metals that are adsorbed on clay surfaces or organic complexes. 1. CO2 contamination of underground drinking water sources 2. CO2 contamination of surface waters 3. Displaced brine contamination of groundwater. 4, EOR oil spill (see **16.22.00**)	Contamination of groundwater resources may result in impacts on flora, fauna and/or humans if the water is abstracted or flows to the surface environment. These potential impacts are considered in the subsequent FEP classes, however, contamination of groundwater may be an endpoint of interest in itself. An increase in CO2 concentration might cause a decrease in pH to a level of 4-5, which might cause calcium dissolution, increase in the hardness of water and alteration of minerals from minerals from rocks and soils that could release elements such as heavy metals into the water supply. Foundations of buildings could be damaged by seepage of groundwater containing CO2 in shallow unconsolidated sediments and soils. This could be a problems if CO2 were to be stored (and leak) underneath, for example, historical city centers, other heritage objects, or archeological sites (CO2STORE) Surface water could be contaminated by CO2 leakage, which could affect aquatic ecosystems by decreasing pH, especially in stagnant or stratified waters (Damen 2006) Displaced brine may cause undesirable effects such as a rise of the water table (which could have negative impact on land quality and use) and an increase in salinity of sweet water reservoirs used for drinking

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246	**07.02.02.00.**	Impacts on soils and sediments	Soils and sediments may have elevated concentrations of CO2, should it leak from the storage system, and/or other contaminants, such as heavy metals, hydrocarbons (e.g., EOR and ECBM) or even increased salinity resulting from CO2 sequestration. For example, natural CO2 leaking from a trapped reservoir near Mammoth Mountain, in California, has resulted in soil gas concentrations of 20 to 90%. 1. Contamination of soil 2. Contamination of sediments	Increased CO2 concentrations and/or contamination of soils and sediments with associated substances may be sufficient to modify the ecology and/or use of the impacted area by humans.
247	**07.02.03.00.**	CO2 release to the atmosphere	Release of CO2 (or other contaminants, such as radon or methane, mobilized as a result of the sequestration) to the atmosphere from the storage system .	Release of sequestered CO2 or mobilized methane to the atmosphere will reduce the effectiveness of the storage system at preventing greenhouse gases from being emitted to the atmosphere. Atmospheric contamination could also lead to health impacts on humans and wildlife. Rapid release likely to effectively disperse the CO2 higher in the atmosphere. Moderate release likely to concentrated CO2 near the ground, representing the highest risk. Slow release likely to disperse CO2 in the soil and atmosphere.
248	**07.02.04.00.**	Impacts on exploitation of natural resources	The impact of CO2 sequestration on the exploitation of natural resources such as oil and gas. Enhanced oil recovery (EOR) and enhanced coal bed methane (ECBM) recovery projects involving the injection of CO2 are based on improved recovery of oil and methane respectively resulting from CO2 sequestration. However, CO2 sequestration may result in the contamination of geological resources (such as hydrocarbons and minerals) or inhibit their recovery or future exploitation. Note that the potential impact on groundwater resources is considered in Impacts on groundwater. 1. Contamination of mineral resources 2. Contamination of mineable coal seams 3. Contamination of oil resources 4. Contamination of natural gas resources 5. Contamination of geothermal resources 6. Contamination of pore space owned by others.	Impacts on the exploitation of natural resources can be positive (such as EOR and ECBM) and/or negative (such as inhibited recovery). These may result in other (for example, financial) impacts, or may be endpoints of interest in themselves.
249	**07.02.05.00.**	Modified hydrology and hydrogeology	The injection of CO2 may result in modifications to both the deep hydrogeology and near-surface hydrology.	Changes in the deep hydrogeology or near-surface hydrology may affect aquifer abstraction or even surface hydrology for groundwater driven features. These impacts may be either positive or negative.
250	**07.02.06.00.**	Modified geochemistry	The injection of CO2 will modify the geochemistry of the sequestration system. This may be confined to the immediate vicinity of the storage location, or, through leakage from the reservoir, may affect other locations.	The extent of geochemical modifications may be an endpoint of interest, due to resulting changes to geological processes. For example, the acidification of the geochemical regime may cause minerals to be dissolved, with potential implications for the porosity and stability of the geological formations.
251	**07.02.07.00. (See 03.02.06.00)**	Modified seismicity	Injection of supercritical CO2 into a geological formation may induce seismic events and processes.	Induced seismicity may be an endpoint of interest in itself, or it can result in other impacts, such as physical disruption of the surface environment.

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252	**07.02.08.00.**	Modified surface topography	The gradual or sudden sinking (subsidence) or elevation (uplift) of the topography of the terrestrial surface or marine sea-bed.	Deformation of the terrestrial surface or sea-bed may be an endpoint of interest in itself, or may result in other impacts, such as damage to property.
253	**07.02.08.01.**	Sinkhole formation	Addition of CO2 in a limestone or carbonate-rich aquifer could result in dissolution of the rock matrix and the enlargement of voids. If this process takes place at relatively shallow depth collapse may result in subsidence at the surface and sinkhole formation. For example, CO2 leakage around a borehole drilled to extract natural CO2 from a reservoir in Florina, Greece, resulted in subsidence around the borehole that filled up with water.	Large scale collapse structures may cause significant change to surface topography and possible CO2 migration paths. Sinkholes can provide locations where leaking CO2 can accumulate.
254	**07.03.00.00.**	Impacts on flora and fauna	FEPs relevant to impacts on flora and fauna. 1. Natural flora and fauna 2. Agricultural flora and fauna	Impacts on flora and fauna can be postulated as a result of sequestration operations, even if there are no associated impacts to humans.
255	**07.03.01.00.**	Asphyxiation effects	Asphyxiation effects of CO2 on terrestrial and aquatic fauna. Oxygen is an essential requirement for respiration in animals and is therefore needed to sustain life. High concentrations of CO2 in air or water will lead to suffocation of terrestrial and aquatic animals due to a lack of oxygen reaching the blood stream. If meteorological conditions do not disperse CO2 released to the atmosphere, it can gather close to the surface and remain in depressions, such as natural hollows. This property allows CO2 to reach high concentrations if released in sufficient quantities under particular atmospheric conditions. The 1986 Lake Nyos disaster in Cameroon provides a graphic example of the potential effects of high atmospheric concentrations of CO2. A large limnic eruption resulted in the death of wildlife and approximately 1800 people in the surrounding area and up to 27 km away. In a similar way to gaseous CO2 being denser than air, water containing high concentrations of dissolved CO2 is denser than pure water, a factor that contributes to the limnic eruption phenomenon observed at Lake Nyos. In addition to the possibility of dissolved CO2 causing asphyxiation in aquatic organisms, if gaseous CO2 forms a layer at the surface of water bodies, it can prevent the oxygenation of the water and lead to a reduction of the O2 concentration thereby contributing to asphyxiation of aquatic	Levels of CO2 from a sequestration project sufficient to cause asphyxiation of fauna would be an endpoint of concern in assessing the geological sequestration of CO2.
256	**07.03.02.00.**	Effects of CO2 on plants, algae, fungi and microorganisms	Plants, algae, fungi and microorganisms (in both terrestrial and aquatic environments) use energy in sunlight to photosynthesize carbohydrates from CO2 and water (H2O). Increasing concentrations of CO2 around the photosynthetic tissues, increases the rate of photosynthesis and therefore growth and productivity in terrestrial and aquatic plants and algae. However, the roots of most plants need oxygen to breakdown carbohydrates to provide energy for root growth and healthy metabolism, a process called aerobic respiration. High concentrations of CO2 in the soil reduces the availability of O2 and can cause roots and therefore plants to die. At Mammoth Mountain, in California, CO2 has accounted for up to 95% of the gas concentration in soil at the edge of Horseshoe Lake due to release from natural geological CO2 reservoirs caused by volcanic activity. These high soil concentrations have resulted in areas of forest being killed.	Concentrations of CO2 in the soil, atmosphere and/or water sufficient to impact on the growth of plants and algae would be an endpoint of interest in assessing the geological sequestration of CO2.

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257	**07.03.03.00.**	Ecotoxicology of contaminants	Ecotoxicology deals with the toxic effects of contaminants on the biosphere. Contaminants other than CO2 may be introduced to the biosphere as a result of geological CO2 sequestration due to: - impurities associated with the sequestration fluid, such as hydrogen sulfide (H2S), methane (CH4), nitrogen oxides (NOx) and mercaptans; - the mobilization of substances in the geological environment due to the sequestration of CO2, such as hydrocarbons (e.g., EOR and ECBM), brine, CH4 and heavy metals. These substances may have a toxic effect on organisms in the biosphere, including plants, animals, algae and fungi.	The potential for contaminants associated with and/or mobilized by CO2 sequestration to have a toxic effect on organisms should they migrate to the biosphere will be of interest in an assessment of the geological sequestration of CO2. Methane leakage may affect shallow water quality and pose a lethal threat when accumulating in confined spaces such as basements/cellars. The global warming potential of methane is circa 23 times that of CO2 (Damen 2006)
258	**07.03.04.00.**	Ecological effects	Geological sequestration of CO2 may have an impact on the biosphere at a community, population and/or ecological level, with subsequent implications for biodiversity. The potential impact of releases of CO2 and associated or mobilized contaminants into the biosphere may disrupt biological interactions sufficiently to modify the terrestrial or aquatic ecosystems affected. For example, the sudden release of natural CO2 due to the limnic eruption at Lake Nyos, Cameroon, resulted in the sudden death of wildlife, but was unlikely to affect the ecology in the longer term. However, the continued gradual release of natural CO2 into soil near Mammoth Mountain, California, has been sufficient to kill trees and damage the local ecosystem since 1996 until the present day.	The degree of potential ecological disruption resulting from geological CO2 sequestration may be an endpoint of interest, especially if the ecosystem affected is considered valuable and/or sensitive to perturbations.
259	**07.03.05.00.**	Modification of microbiological systems	Microbes will be present in the geosphere as well as in the terrestrial and/or marine environments above the CO2 storage reservoir. CO2 sequestration may disrupt microbial aerobic respiration but may enhance anaerobic respiration, with subsequent implications for the processes in which the microbes are involved. Microbes play an important roll in all terrestrial and aquatic ecosystems, including those associated with extreme environments, such as deep sea hydrothermal vents.	The potential impact of CO2 sequestration on aerobic and anaerobic microbial respiration in the geosphere, terrestrial and aquatic biosphere may be an endpoint of interest.
260	**07.04.00.00.**	Impacts on humans	FEPs relevant to adverse impacts on people.	A range of possible impacts to human beings can be postulated as a result of sequestration operations.

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261	**07.04.01.00.**	Health effects of CO2	Elevated atmospheric concentrations of CO2 can result in both acute and chronic health effects in humans. If meteorological conditions do not disperse CO2 released to the atmosphere, it can gather close to the surface and remain in depressions, such as the basement of buildings or at the surface of lakes. This property allows CO2 to reach high concentrations if released in sufficient quantities under particular atmospheric conditions. The primary health effect of concern is asphyxiation. High concentrations of CO2 in air will lead to suffocation of humans due to a lack of oxygen reaching the blood stream. Asphyxiation can occur once atmospheric concentrations reach approximately 10% CO2. Other health effects include those directly associated with elevated concentrations of CO2 in the blood stream, such as acidosis and physiological responses to the elevated blood CO2. The 1986 Lake Nyos disaster in Cameroon provides a graphic example of the potential effects of high atmospheric concentrations of CO2. A large limnic eruption resulted in the death of approximately 1800 people in the surrounding area and up to 27 km away. (Note that this event resulted from natural volcanic activity rather than CO2 storage). Asphyxiation requires high CO2 concentration in occupied (usually confined) space, plus either poor ventilation or high release rate	The potential for CO2 to be released to the atmosphere in sufficient quantities to cause health effects in humans will be an endpoint of interest in assessing the geological sequestration of CO2. CO2 combined with CO is more toxic than when CO2 or CO exist separately (Duncan 2012).
262	**07.04.01.01.**	Elevated CO2 in air	CO2 = 5000 ppm (0.5%): OSHA permissible exposure limit: Time weighted average concentration for 8-hour work day. American Conference of Governmental Industrial Hygienists (ACGIH) threshold limit value: Time weighted average concentration for normal 8-hour work day or 40-hour work week. CO2 = 30,000 ppm (3%): Breathing increases to twice normal rate and a person would experience impaired hearing, headache, and increased blood pressure (Shell). Occupational Safety & Health Administration (OSHA) short-term exposure level: Maximum concentration for 15-minute period (maximum of 4 periods per day with at least 60 minutes between exposure periods). CO2 = 40,000 ppm (4%): National Institute for Occupational Safety and Health (NIOSH) immediate danger to life and health: The maximum level to which a healthy individual can be exposed to a chemical for 30 minutes and escape without suffering irreversible health effects or impairing symptoms. CO2 = 50,000 ppm (5%): Breathing increases to approximately 4 times normal rate, symptoms of intoxication become evident and slight choking may be felt (Shell). CO2 = 75,000 ppm (7.5%): A sharp odor is noticeable. At this level a person would experience very labored breathing, headache, visual impairment, and ringing in the ears. Judgment may be impaired, followed within minutes by loss	CO2 combined with CO is more toxic than when CO2 or CO exist separately (Duncan 2012).
263	**07.04.02.00.**	Toxicity of contaminants	Contaminants other than CO2 may be introduced to the biosphere as a result of geological CO2 sequestration due to: - impurities associated with the sequestration fluid, such as hydrogen sulfide (H2S), methane (CH4), nitrogen oxides (NOx) and mercaptans; - the mobilization of substances in the geological environment due to the sequestration of CO2, such as hydrocarbons (e.g., EOR and ECBM), CH4 and heavy metals. Such contaminants may be toxic to humans and could cause harm if exposure pathways exist. The toxicity will depend on: the form of exposure, e.g. ingestion or inhalation, leading to internal exposure or	The potential for contaminants associated with an/or mobilized by CO2 sequestration to cause harm to humans is an endpoint of interest when assessing the geological sequestration of CO2. CO2 combined with CO is more toxic than when CO2 or CO exist separately (Duncan 2012).

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264	**07.04.03.00.**	Impacts from physical disruption	Impacts on humans due to physical disruption of the environment caused by geological CO2 sequestration. For example, damage to buildings due to induced seismicity, damage to farmland due to subsidence or uplift.	Physical disruption of the environment caused by CO2 sequestration may have a detrimental impact on humans.
265	**07.04.04.00.**	Impacts from ecological modification **(See 06.01.08.00)**	Impacts on humans due to ecological modification. These may be negative (for example, reduced timber yields due to damage caused to trees by CO2 in the soil) or positive (for example, increased crop yields due to higher atmospheric CO2).	Ecological modification caused by CO2 sequestration may have a positive or negative impact on humans.
266	**08.00.00**	**ECONOMIC RISKS**		
267	**08.01.00.**	Cost escalation / inflation	Cost escalation/inflation may be higher than budgeted. Cost escalations are of particular concern because field-service costs (drilling, geophysics, etc.) and equipment may continue to increase as the price of oil stays high. Key cost items that may be effected by escalation/inflation include: 1. Steel cost 2. Other material cost 3. Equipment cost 4. Labor cost 5. Imported goods cost (due to currency exchange) 6. Financing/risk transfer costs 7. Assessment and permitting costs 8. Mitigation and closure costs	The risk of cost escalations is significant; cost increases may force a change in scope-of-work.
268	**08.02.00.**	CO2 value/cost	Incentives for CO2 capture and storage are particularly important for CO2 sequestration in deep saline aquifers. In this case, the value or cost of CO2 may be determined by cap-and-trade, carbon tax or emission credits. In EOR and ECBM the value of CO2 may be tied to the price of oil or natural gas. However, the cost of CO2 capture and transport may be higher or lower than the assigned value. Value of emission credits provide incentive for CO2 sequestration, particularly in deep saline aquifers (DSA). CO2 purchase cost higher than budgeted. CO2 has traditionally been purchased for EOR and ECBM use. Economic arrangements among project participants could have negative project impacts under changed or unanticipated conditions. 1. Value of CO2 emissions credits lower than budgeted 2. CO2 purchase cost higher than budgeted	A low value for emission credits may be insufficient to cover the cost of CO2 capture and sequestration in deep saline aquifers.

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269	**08.03.00.**	Price of oil (or other related commodities)	The prices of related commodities can impact the value and/or availability of CO2. 1. Oil price - impacts EOR economics 2. Natural gas price - impacts ECBM economics 3. Fertilizer price - impacts CO2 supply from fertilizer plants 4. Ethanol price - impacts CO2 supply from ethanol plants 5. Cement price - impacts CO2 supply from cement plants	Low commodity prices can impact the viability of a CO2 capture and storage project. An economic downturn can cause capital constrains and significant energy price volatility leading to: 1 Business failures of vendors, suppliers or customers. 2. Failure of hedging counterparties to fulfill delivery or purchase obligations 3. Decreased consumption of commodities 4. Increased cost of capital and increased difficulty accessing capital.
270	**08.04.00.**	Project development costs	Project development costs that could be higher than expected or budgeted include: 1. Surface land and/or pore space access costs -purchase or lease 2. Water rights costs 3. Mineral rights costs - needed for EOR or ECBM 4. Pipeline right-of-way (ROW) costs 5. Site characterization costs 6. Permitting costs 7. Technology licensing costs 8. Engineering, procurement and construction (EPC) costs 9. Insurance costs 10. Project financing costs 11. Legal costs 12.Closure and post-closure costs	High project development costs can make the project economically infeasible. Project may be halted if some of the necessary requirements are unobtainable.
271	**08.05.00.**	Project capital costs	Project capital costs that could be higher than budgeted include: 1. CO2 capture system 2. CO2 dehydration 3. CO2 compression 4. CO2 pipeline 5. Well head system 6. CO2 recycle system - for EOR 7. Oil tankage - for EOR 8. Natural gas processing system - for ECBM 9. Water tankage - for EOR or ECBM 10. Water treatment system - for EOR or ECBM 11. New well drilling and completion 12. Old well remediation/replugging 13. Old well workover 14. Site preparation 15. Access roads 16. Power supply system 17. Water supply system 18. Communications system 19. Monitoring system costs	High project capital costs can make the project economically infeasible. Accidental loss can result in Business Interruption / Advanced Loss of Profit type exposure, or even result in the project becoming uneconomic to continue.

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272	**08.06.00.**	Operating and maintenance costs	Project operating and maintenance costs that could be higher than budgeted include: 1. CO2 capture operating costs 2. CO2 dehydration/compression operating costs 3. CO2 pipeline operating costs 4. Injection operating costs 5. Monitoring costs 6. Simulation modeling costs 7. Maintenance costs 8. Lease operating expenses 9. Management fees 10. Working capital 11. Severance and ad valorem tax 12. Investor reporting costs 13. Power cost 14. Make-up water cost 15. Water treatment/disposal cost 16. Labor cost 17. Security costs 18. Site close costs 19. Verification costs 20. Regulatory compliance costs 21. Insurance costs 22. Cost for loses 23. Post-closure costs for DSA	High operating and maintenance costs can impair project economic viability. Accidental loss can result in Business Interruption / Advanced Loss of Profit type exposure, or even result in the project becoming uneconomic to continue.
273	**08.07.00.**	Project Financing	Factors which could impact project financing include: 1. Government project funding withdrawn for technical reasons. 2. Government project funding withdrawn for political reasons 3. Change in equity project funding 4. National/global economic downturn impact on project financing 5. Lack of economic incentives for CCS impact on project financing 6. Private financing	Lack of or loss of project financing could halt the project or delay expansions. High level of indebtedness can lead to: 1. Restrictions on business operation due to terms of the debt agreements 2. Use of substantial portion of cash flow to pay interest on outstanding debt 3. Competitive disadvantage compared to competitors with proportionally less debt 4. Impairment of additional financing for working capital, capital expenditures, debt servicing, restructuring, acquisitions, or general corporate purposes 5. Limited flexibility in planning for, or reacting to, changes in the business and industry 6. Vulnerability to economic downturns and adverse business developments 7. Vulnerability to interest rate increases.
274	**08.08.00**	Hedging or derivative positions	Hedging or derivative positions may be used as a risk management tool to control the adverse impact of fluctuating commodity prices.	Hedging arrangements are used to reduce exposure to fluctuations in commodity prices (i.e., CO2, oil, natural gas). Hedging can create financial risks when: 1. Production is less than hedged amount. 2. The counterparty to the hedging contract defaults on its contract obligations 3. Change in the expected differential between the underlying price in the hedging agreement and the actual price received 4. Limitation of the benefit when commodity prices increase Under certain circumstances, or if hedges are deemed ineffective, discontinued, or terminated for any reason, substantial financial losses may be incurred in closing out a company's position.
275	**09.00.00.**	**PERMITTING RISKS**		

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276	**09.01.00.**	Permit compliance - obtain or maintain permits	Permitting and NEPA compliance are lengthy processes, and are subject to even more delays because of uncertainty associated with permitting sequestration (a relatively new issue for federal, state and local regulatory agencies).The procedures for permit compliance could cause delays. Potential permits required for a CCS project include: 1. National Environmental Policy Act (NEPA) - Environmental Assessment (EA) - Environmental Impact Statement (EIS) 2. Underground Injection Control (UIC) permit 3. CO2 storage permit 4. Drilling permit 5. Water discharge/disposal permit 6. Crossing permits for wetlands, federal land, tribal land, railroads, highways, roads 7. Construction general permit 8. Storm water discharge permit 9. Air quality construction permit 10. Seismic permit 11. Storage tank permit 12.Closure financial assurance 13. Post-closure financial assurance	Lack of permit could halt or restrict construction or operation; permit delay could have other impacts including increased costs.
277	**09.02.00.**	Public outreach and education	Public acceptance support and trust is critical to obtaining environmental permits. Public outreach and education can be more difficult than expected. 1. Lack of public acceptance that CO2 emissions contribute to global warming 2. Lack of public acceptance that global warming is an eminent danger to society 3. Lack of public that carbon capture and storage (CCS) is safe 4. Poor public perception of CCS projects 5. Local community actions and reactions 6. Special interest groups or non-governmental organizations actions and reactions 7. Lack of political support for the project 8. Risk off-sets	Failure to get public acceptance for a project can lead to significant delays in, and costs for, permitting An unexpected situation arises that is not technically impacting but the appearance of unpreparedness spurs public concern.
278	**09.03.00.**	Saline water extraction, treatment and disposal	Large amounts of saline water are pumped out of the ground for EOR and ECBM. EOR water production increases over time. In high water cut cases, water may represent 99% of the production volume and oil only 1% of the volume. ECBM employs water production to lower the over pressure in the coal seam, decrease swelling and increase permeability. Water may be extracted in a DSA operation to make room for injected CO2 and manage pressure. Extracted water is increasingly becoming a prominent issue, particularly deliberately extracting water to manage CO2 plume (e.g. extracting water to encourage plume migration and reinjecting the extracted water into a different part of the reservoir so that it is not extracted again). Some researchers believe CO2 can be injected into reservoirs without extracting water. This may be true in an open storage reservoir. But in a closed reservoir, injecting CO2 without extracting water will build up pressure in the reservoir and severely restrict the CO2 storage capacity. CO2 changes water composition and makes water more acidic (pH 4-5). Therefore EOR and ECBM production water may require more treatment before it can be disposed of.	Saline water disposed could be one of the most critical issues in permitting. Treating the water will concentrate brine that will need to be reinjected.

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279	**09.04.00**	Natural resources nearby	1. Mineral resources 2. Mineable coal seams 3. Oil reservoirs 4. Natural gas reservoirs 5. Underground drinking water sources 6. Surface waters - lakes, rivers, streams 7. Geothermal resources 8. Pores space owned by others 9. Deep saline aquifers 10. Microbial resources 11. Soil - farmland 12. Flora and fauna - endangered species and critical habitats	CO2 or brine fluid migration could contaminate others' natural resources and lead to permitting delays due to legal contest.
280	**09.05.00.**	Dense population nearby	Present and future urban sprawl. 1. Sensitive receptors (schools, hospitals, care centers, churches, prisons) in or near injection site 2. Dense population located downhill or downwind of injection site 3. Populated subsurface structures located nearby	Additional safety precaution measures are required to protect against CO2 leakage in dense population areas..
281	**09.06.00.**	Conflicts with use of surface	1. Agriculture 2. Fishing 3. National parks/monuments 4. Wetlands 5. Timberland 6. Recreational areas 7. Military areas 8. Heavy industry sites 9. Urban areas 10. Archeological sites 11. Tribal sacred ground 12. Endangered species critical habitats 13. Bird sanctuaries 14. Historical sites 15. Groundwater protection zones. 17. Change in land use (zoning change)	Some land uses may impact site selection and permitting. Others may require additional monitoring and modeling to provide added protection from CO2 leakage. Nearby heavy industry can interfere with seismic readings. Land use changes could restrict access to and use of land for CO2 sequestration
282	**09.07.00.**	Conflicts with use of subsurface	Conflicts with use of the subsurface may include: 1. Natural gas storage 2. Compressed air storage 3. Geothermal plants 4. Radioactive waste disposal 5. Petroleum production 6. Coal mining 7 Health spas	Could impact site selection and permitting.
283	**09.08.00.**	Permit denied or modified by government agency	A permit may be modified by government agency to require increase data access and approval by NGOs and/or public 1. Permit denied because the project is considered high risk to public 2. Permit denied because there is uncertainty over the safety of the project 3. Permit revoked due to owner failing to comply with regulations (action or inaction) 4. Permit delayed due to owner action or inaction	Causes delays leading to price escalation. Could halt the project.

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284	**09.09.00.**	Pre-existing contaminated site	Site may have already been contaminated by non-CO2 storage related activities.	Pre-existing contamination of groundwater, surface water, and/or soil. Requires assessment to determine if proposed project would be impacted by or exacerbate existing condition. Or assume responsibility for remediation of pre-existing conditions.
285	**10.00.00.**	**EXTERNAL RISKS**		
286	**10.01.00.**	Natural disaster risks (01.02.02.00.)	1. Fire -wildfires, industrial fires 2. Flood - flood plain, dry wash areas, flash floods, tsunami, debris flows 3. Earthquake - natural seismic activity, rock slides, mud slides 4. Winter storms - blizzards, ice storms, arctic cold 5. Hail storm 6. High winds - tornadoes, hurricanes, typhoons, cyclones 7. Heat wave 8. Drought 9. Heavy rain - monsoons, tropical storms, thunder storms 10. Lightning 11. Sand/dust storms 12. Avalanche 13. Electromagnetic disturbances - sunspots 14. Volcano 15. Corrosive atmospheres - high humidity, coastal sea breeze, industrial plant acid gas emissions	Natural disasters can delay, impair or shutdown a project.
287	**10.02.00.**	Security risks	1. Theft 2. Vandalism - onsite equipment or offsite monitoring equipment 3. Employee sabotage 4. Civil unrest - riots, civil war, rebellion, insurrection, military or usurped power or confiscation 5. Terrorist activities 6. War - invasion, acts of foreign enemies, hostilities 7. Nationalization 8. Government sanctions, blockade, embargo 9. Labor disputes - strike, lockout 10. Damage to surface facilities by human activity 11. Hunting season - stray bullets	Risks to employees, public and equipment.
288	**10.03.00.**	Competition	Other projects in the area may compete for the same CO2, labor, infrastructure, land, pore space, funding 1. Interaction with adjacent CO2 sequestration sites 2. Infringement of project's pore space by third-party injection of CO2, water or waste disposal	Could halt the project or increase costs. Potential decreased storage capacity.

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289	**10.04.00.**	CO2 supply	Changes in the operation of the CO2 source plant may impact CO2 properties and/or flow rate. Unanticipated change in demand for injected CO2 (flow rate, pressure, water content, etc.) due to either uncontrollable physical changes or operating decisions, will affect operations of the CO2 source facility and potentially impose stresses upon surface and down hole equipment and borehole. Changes may be gradual or sudden. Also includes changes arising from characterization data, e.g., limits placed by reservoir on injectivity, capacity, etc. CO2 sources and sinks need to coordinate supply and demand and scheduled outages to avoid constraint startup/shutdown of compression facilities and maintain consistent pipeline pressure. This is normally done through a nomination process at least one week in advance. Operators of CO2 storage projects may incorporate excess injection capacity (i.e. spare wells) to permit continued injection during planned or unplanned well downtime. (CCP 2009)	Interruption of CO2 supply could result in a Business Interruption / Advanced Loss of profit type exposure, or even result in the project becoming uneconomic to continue. Lack of adequate CO2 supply could halt or limit injection. Intermittent injection schedule could increase stress on surface and down hole mechanical elements, could affect EOR/ECBM sweep efficiency, and could increase concentrations of various contaminants in the injected gas. The timing of CO2 availability may not match up with the time when CO2 is needed for EOR or ECBM. 1. CO2 outside of design specification - flow rate, composition, pressure, temperature 2. Change in CO2 supply conditions 3. Change in CO2 demand conditions 4. CO2 supply interruptions due to source plant outage/failure 5. CO2 supply interruptions due to CO2 capture outage/failure 6. CO2 supply interruptions due to compressor outage/failure 7. CO2 supply interruptions due to pipeline outage 8. Disparity in timing CO2 supply/demand 9. CO2 interruption due to accident at the CO2 supplier
290	**10.05.00.**	Water supply	1. Water supply design specifications - Flow rates - Composition - Pressure - Temperature 2. Water supply interruptions	Could impact water and gas (WAG) flooding
291	**10.06.00.**	Power supply	1. Power surges 2. Power brown outs 3. Power interruptions (black outs)	Could shut operations down.
292	**10.07.00.**	Communication system	Communications could be interrupted. The SCADA system may be dependent on one or more of the following communications systems: 1. Phone line 2. Fiber optics 3. Satellite 4. Internet	Loss of communication system could impair operations especially if the SCADA link is disconnected.
293	**10.08.00.**	Road access	Road to injection site could be blocked by snow, accident, washout, wildfire, flooding	Lack of road access to sites could impair operations
294	**11.00.00.**	**PROJECT MANAGEMENT RISKS**		
295	**11.01.00.**	Management team	The project may include some unfamiliar activities and workflows, may acquire and respond to a wide range of newly acquired data, and may experience changes in objectives. Operational conflicts, anticipated or not, could impact project values. Inexperienced managers tend to be over optimistic in taking risks and taking short cuts. for example: failing to avoid high risk sites. 1. Inexperienced management team 2. Inability to execute contracts among project partners in a timely manner 3. Lack of stakeholder coordination	An inexperienced management team has a higher potential for mistakes and poor judgment Inefficient interface management can result in delays and failure to achieve project goals.
296	**11.02.00.**	Operator training	1. Under qualified operators 2. Untrained operators 3. Operator error	Inadequate operator training can result in low labor productivity and greater potential for human error.

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297	**11.03.00.**	Execution strategy	Poor execution strategy can result from: 1. Insufficient funding 2. Insufficient resources 3. Unrealistic schedule 4. Schedule and planning conflicts (02.01.05.00) 5. Poor timing 6. Lack of risk management plan Scheduling and planning covers the sequence of events and activities occurring during all phases of the project.	Poor execution strategy can result in project delays and increased project costs. Project development decisions generally are based on subjective judgments and assumptions that, while they may be reasonable, are by their nature speculative. It is impossible to predict with certainty the production potential of a particular property or well. Furthermore, the successful completion of a well does not ensure a profitable return on investment.
298	**11.04.00.**	Record keeping **(See 02.02.03.00.)**	Large amounts of data will be generated by the project. Data could be poorly communicated between groups, or be badly managed to the point that important data is lost, or used incorrectly. Features related to the retention of records of the content and nature of a CO2 storage site after closure and also the placing of permanent markers at or near the site. 1. Poor data management 2. Loss of archives/records 3. Unable to accurately verify the amount of CO2 retained in storage	It is expected that records will be kept to allow future generations to recall the existence and nature of the storage reservoir/aquifer following closure. Insufficient record keeping could lead to noncompliance with regulations and failure to achieve project goals.
299	**11.05.00.**	Multi-party project	CCS projects may involve multiple participants for CO2 supply, CO2 transportation, EPC (engineering, procurement and construction), CO2 storage, computer simulation, MVA (monitoring, verification and accounting), carbon trading. and risk management. There are challenges and risks in coordinating the responsibilities and liabilities among multiple organizations involved in a project. In case of too deep involvement of partners in day to day operations, shareholders may assume joint and several liability for actions of the partnership. Disagreement among partners may lead to deadlock in unanimous decision making.	Lack of communication, coordination and cooperation among project participants can lead to project delays and failure to achieve project objectives.
300	**11.06.00**	Pre-closure administrative control (02.01.06.00.)	Features related to measures to control events at or around the sequestration site during the design, construction, operation and decommissioning phases. The type of administrative control may vary depending on the stage in the storage system lifetime. (02.01.06.00.)	The pre-closure administrative control will influence the quantity and quality of information about the sequestration project that is available post-closure, therefore helping to determine societal memory. The better the amount and quality of information available, the lower the possibility of inadvertent intrusion.
301	**11.07.00**	Post-closure administrative control (02.02.01.00.)	Administrative control of the sequestration site after closure of the project. The administrative control of the post-closure site may differ from that of the pre-closure site with subsequent implications for the resources available for administrative control, the degree of access and availability of information etc.	There may be potential for loss of information in any transfer of administrative control. A lack of awareness about the details of a CO2 sequestration project could result in inadvertent disruption in the future.

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302	**11.08.00**	Quality Control **(See 02.01.08.00.)**	Features related to quality control procedures and tests during the design, and operation of the storage system. It could be expected that a range of quality control measures would be applied during operation of the storage system and supply of CO2 to be sequestered. There may be specific regulations governing quality control procedures, objectives and criteria.	The degree of quality control during the design, construction, operation and decommissioning of a sequestration system can affect the post-closure performance by influencing the integrity of the engineered parts of the system (borehole seals, for example) and by influencing the quantity, quality and accuracy of records. Quality of equipment could have a big impact on the project.
303	**11.09.00**	Monitoring	There are many market and business conditions that should be monitored by management in order to make informed business decisions. These may include: 1. Environmental conditions 2. Public health 3. Public opinion 4. Legislation and regulations 5. Economic conditions 6. Operations 7. Natural resources 8. Water supply 9. Transportation logistics 10. Construction schedule 11. Climate change and weather conditions 12. Security 13. Pipeline 14. CO2/brine movement 15. Operating permit requirements.	Effective decision making requires timely knowledge and understanding of all factors that may influence or be influenced by the decision.
304	**12.00.00.**	**ENGINEERING RISKS**		
305	**12.01.00.**	Technical design	Technical design errors can be cause by: 1. Insufficient data 2. Lack of data - typical of greenfield sites 3. Inaccurate data 4. Misinterpretation of data 5. Use of wrong standards - unit conversion 6. Specification errors 7. Undefined specifications 8. Ignoring data 9. Calculation and modeling errors 10. Failure to design for full range of operating conditions and climate conditions. 11. Failure to design for high operating availability 12. Failure to design for failsafe protection for compression	Technical design errors can lead to poor performance or failure of equipment/systems and possible CO2 release.
306	**12.02.00.**	Modeling and simulation	Use of multiple static and dynamic models that are populated and run by different people using different assumptions and methods can result in errors.	Modeling and simulation errors can result in uncertainties, interpretive disagreements and poor operational choices.
307	**12.03.00.**	Baseline studies	Baseline surveys are important for determining ambient or background conditions prior to CO2 injection. They include: 1. Soil baseline 2. Water (surface and groundwater) baseline 3. Atmosphere baseline 4. Seismic baseline 5. Aquatic environment baseline 6. Fauna baseline 7.Flora baseline 8.Land use 9. Natural resources 10. Population 11. Local/regional economic baseline 12. Formation chemical baseline 13. Injection site contamination 14. Coastal features 15. Local oceanography 16. Aquatic sediments 17. Location and condition of existing wells 18. Formation geophysical baseline	Without baseline surveys the project will be unable to quantify what impact the project has had on the environment.
308	**13.00.00.**	**PROCUREMENT RISKS**		

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309	**13.01.00.**	Procurement delays	Procurement delays may threaten project goals. Infrastructure components may include power block, compressors, gas processing equipment, pumps, valving, metering and monitoring equipment. 1. Procurement delays - equipment and infrastructure 2. Procurement delays - drilling services 3. Vendor supply chain disruptions 4. Material supply shortages 5. Changes in materials and equipment costs	Could delay completion of construction
310	**13.02.00.**	Vendor errors	1. Vendor engineering errors 2. Defective manufacturing	Potential poor performance or failure of equipment/systems. Potential CO2 leakage.
311	**13.03.00.**	Contracting	The ability of project partners to formulate and execute contracts with third parties (non-partners) in a timely manner (not causing delays) apart from their specific contents. 1. EPC contract omissions 2. EPC contract insufficient detail 3. EPC contract change orders	The principal risk is delay and its impact upon achieving goals including cost.
312	**13.04.00.**	Transportation logistics	Project-related traffic in and out of site; its effects upon both injection well, monitoring and CO2 supply operations. 1. Site traffic impact on injection and monitoring 2. Limitations on size/height/weight shipments to site	Could cause interruptions and delays.
313	**14.00.00.**	**CONSTRUCTION RISKS**		
314	**14.01.00.**	Cost overruns	Construction cost overruns can be due to 1. Change orders 2. Cost escalation 3. Unexpected problems 4. Rework 5. Poor management.	Increased costs
315	**14.02.00.**	Schedule delays	Construction schedule delays can be due to 1. Permitting delays 2. Bad weather 3. Labor issues 4. Procurement delays 5. Accidents 6. Poor planning/management 7. Funding delays	Startup delay and increased costs.
316	**14.03.00.**	Construction defects	Construction defects may be identified during or after construction. They may include 1. Improper installation 2. Wrong installation 3. Damage during installation 4. Defective welding 5. Omissions	Increased costs, project delays due to need for rework, and potential human injury and equipment/systems damage
317	**15.00.00.**	**COMMISSIONING AND STARTUP RISKS**		
318	**15.01.00.**	Major rework	Major rework may be required to correct poor performance or failure of equipment/systems due to improper design, manufacturing, construction or operation.	Project delays and added costs.
319	**15.02.00.**	Unable to achieve design capacity	Operating capacity may be limited due to improper design, manufacturing, construction or operation.	Loss of revenues and increased costs.
320	**15.03.00.**	Operator error or over confidence during commissioning and startup	Incorrect operation due to lack of operator training	Potential human injury, equipment damage, project delays, added costs.
321	**15.04.00.**	Startup pressure	Facilities sometimes do not have sufficient pressures to re-start injection. In these cases, injection tubing should be loaded with sufficient fluids to allow for a re-start. (CCP 2009)	Insufficient startup pressure can result in operating delays.
322	**16.00.00.**	**FIELD SAFETY RISKS**		

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323	**16.01.00.**	Accidents and unplanned events **(02.01.09.00.)**	Events related to accidents and unplanned events during site investigation, CO2 emplacement and closure which might have an impact on long-term performance or safety. Accidents are events that are outside the range of normal operations although the possibility that certain types of accident may occur should be anticipated in operational planning. Unplanned events include accidents but could also include deliberate deviations from operational plans, e.g. in response to an accident, unexpected geological events or unexpected aspects of CO2 quality and injection arising during operations. Project related accidents can be caused by human error or equipment/system failure/malfunction. Accidents may occur during construction, commissioning, operation, maintenance or closure. Non-project related accidents may include: rupture of train or truck transport vessel, train derailment, site or water supply contamination. 1. Project related accidents 2. Non-project related accidents	Potential for human injury and/or equipment damage Accidental loss can result in Business Interruption / Advanced Loss of Profit type exposure, or even result in the project becoming uneconomic to continue. Accidents and unplanned events may affect the post-closure performance of the sequestration system. One example may be the incomplete sealing of an injection borehole that may subsequently provide a pathway for CO2 migration.
324	**16.02.00.**	Moving equipment	Moving equipment risks may include: 1. Hitting other equipment 2. Hitting personnel 3. Hitting power lines	Potential for human injury and/or equipment damage
325	**16.03.00.**	Excavation/drilling	The one-call system should be used to locate underground utilities and pipelines before excavating or drilling. Excavation/drilling could hit other subsurface hazards such as gas pockets or underground storage tanks.	Potential for equipment damage, release of gases or liquids, fire, explosion, and/or human injury.
326	**16.04.00.**	Defective equipment	Equipment should be properly maintained and regularly inspected. Equipment defects may include: 1. Exposed electric wiring 2. Leaky hoses 3. Loose connections 4. Frayed cables	Higher risk for equipment failure and human injury

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327	**16.05.00.**	Use of power tools	Operators should be properly trained in the use of power tools.	Potential for human injury and/or equipment damage
328	**16.06.00.**	Contact with rotating equipment	Proper safeguards should be used to prevent contact with rotating equipment	Higher risk for being injured
329	**16.07.00.**	Working near pinch points	Proper safeguards should be used to prevent contact with pinch points	Higher risk for being pinched
330	**16.08.00.**	Working in confined areas	Working in confined areas can represent high risk especially where CO2 is involved.	Higher risk of asphyxiation or being crushed.
331	**16.09.00.**	Working in high places	Working in high places is a common industrial occurrence	Higher risk of injury due to falling
332	**16.10.00.**	Working in trench/ditch	Pipeline construction involves trenching which is subject to cave-ins. Sufficient shielding or cave-in protection devices should be used if people go into a trench	High risk of being crushed and/or asphyxiated

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333	**16.11.00.**	Working under a lifted load	Working under a lifted load should be avoided	Higher risk for being crushed
334	**16.12.00.**	Contact with venomous snakes or insects	Field operations and data collection can be in close proximity to venomous snakes and insects in some parts of the country.	Potential for human injury.
335	**16.13.00.**	Contact with poisonous plants	Field operations and data collection can be in close proximity to poisonous plants such as poison ivy or poison oak in some parts of the country.	Potential of human rash/irritation
336	**16.14.00.**	Contact with hot surface, or exposure to heat or flame	Overheated equipment, welding areas, heaters and open flames are present at industrial sites.	Contact with hot surface or flame can cause burn injuries. Exposure to prolonged high temperatures can cause heat exhaustion or dehydration.
337	**16.15.00.**	Exposure to noise	Operation of heavy equipment, pumps and compressors can generate loud noise.	Prolonged exposure to loud noise can cause hearing damage.
338	**16.16.00.**	Exposure to dust	Dust is generated in pipeline construction and field operations.	Prolonged exposure to dust can cause respiratory health problems.
339	**16.17.00.**	Exposure to hazardous materials	Fluids, fuels and chemicals used in field operations may be classified as hazardous materials.	Prolonged exposure to hazardous materials are known to cause health problems.

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340	**16.18.00.**	Struck by object or flying debris	Drilling can often generate flying debris	Flying debris can cause human injury and/or equipment damage.
341	**16.19.00.**	Release of compressed gases or liquids	Compressed CO2 pipelines, pressurized water lines, compressed air tanks are at risk for rupture.	Release of compressed gases or liquids can cause human injury and/or equipment damage.
342	**16.20.00.**	Ignition of flammable gases or liquids	Acetylene tanks, natural gas lines, liquid fuel lines could be ignited.	Ignition of flammable gases or liquids can cause explosions, severe injuries and property damage.
343	**16.21.00.**	Trips, slips and falls	Trips, slips and falls are common at industrial sites.	Potential for human injury
344	**16.22.00.**	Leaks and spills (related to oil spills rather than CO2, H2S and CH4)	Leaks and spills of lubricants, fuels, chemicals or hazardous materials are common at industrial sites. If they are not promptly taken care of they can lead to more serious problems.	Potential for human injury, equipment damage, fire or environmental damage.
345	**16.23.00.**	Head bumping	Industrial sites are prone to have low hanging or falling objects that could injury unprotected heads	Potential for human head injury
346	**16.24.00.**	Overexertion from manual heavy lifting, pulling, or pushing	Improper lifting of pipes, ducts, bars, boxes, bags, machine parts. Pulling/pushing wrenches, hoses, machine parts or heavy loads.	Potential for human back injury. Overexertion represented 11.3% of injuries requiring days away from work in drilling oil and gas wells in 2007. The injury rate was 2E-03 per worker per year.

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347	**16.25.00.**	On-road driving	Vehicle travel to and from the site is typically among the highest risks in similar projects.	Potential for human injury and/or equipment damage
348	**16.26.00.**	Off-road driving	Field data collection often requires off-road driving, sometimes in rocky, muddy, or steep terrain. Some personnel may lack experience with safe driving under challenging conditions.	Potential for human injury and/or equipment damage
349	**16.27.00**	Explosions and crashes **(01.03.10.00.)**	Events related to deliberate or accidental explosions and crashes such as might have some impact on a closed storage site, e.g. underground nuclear testing, an aircraft crash on the site, acts of war, marine collisions or trawler damage to exposed sea-bed structures. 1. Accidental explosions and crashes 2. Deliberate explosions and crashes 3. Project related 4. Non-project related	Explosions and crashes are likely to be low probability events that could have a significant impact on the performance of the sequestration system by disrupting the expected evolution of the system. Likely to have greater impact on surface facilities rather than subsurface systems.
350	**16.28.00**	Electric shock	Contact with electric current associated with electric machines, tools, appliances, light fixtures, overhead power lines, underground cables, transformers, wiring, and lightning.	Potential for human injury
351	**17.00.00.**	**LEGAL, LEGISLATION & REGULATION RISKS**		

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352	**17.01.00.**	CO2 legislation	Some outstanding CO2 legislation issue are as follows: 1. Cap and Trade or Carbon tax incentives for CCS 2. Certification process for tradable carbon credits 3. Pore space access and ownership 4. Certification for transfer of long-term stewardship/liability for closed CO2 sites from operator to competent legal authority 5. Eminent domain authority 6. Forced unitization for EOR or ECBM 7. Priority of mineral rights over pore space rights 8. Value of escaped CO2 9. Elimination of current tax deductions for oil and gas	Legislation can have a significant impact on CCS project economics. Lack of, or gaps in, CO2 legislation can create uncertainty for the project and make it more difficult to permit and finance the project. Concerns that enacted CO2 legislation could be repealed or changed also contribute to uncertainty for the project and make it more difficult to finance. Elimination of certain oil and gas tax deductions could make it more costly to develop EOR and ECBM projects and negatively affect the financial conditions and results of operations.
353	**17.02.00.**	CO2 regulations	Some outstanding CO2 regulation issues are as follows: 1. CO2 storage permitting and compliance requirements 2. Permitting and compliance for Class VI wells 3. Permitting and compliance for hybrid Class II and VI wells (wells used for both EOR and DSA) 4. Post-injection site care (monitoring) period - EPA proposing 50 years with some flexibility 5. Safety guidelines - DOE best practices guidelines 6. Monitoring and operational reporting requirements 7. Verification and accounting procedures 8. Classification of CO2 as a pollutant rather than a commodity 9. CO2 emission controls and reporting 10. CO2 site straddling two states having to deal with differing regulations 11. Land use restrictions 12. Drilling bonds and other financial responsibility requirements 13. Spacing of wells 14. Reporting on emissions of greenhouse gases 15. Permitting of emissions of greenhouse gases and other regulated air pollutants 16. Utilization and pooling of properties 17. Well stimulation processes 18. Produced water disposal 19. Taxation	Regulations can have a significant impact on CCS project economics. Lack of, or gaps in, CO2 regulations can create uncertainty for the project and make it more difficult to permit and finance the project.
354	**17.03.00.**	CO2 liabilities	Responsibility for the injected CO2 and any associated liability, during and after active project phase, is currently an unresolved legal issue. Project participants could reduce their involvement if this issue remains unresolved, or is resolved in a manner that unacceptably increases their exposure. 1. CO2 ownership and custody 2. Tort-injury to a third-party (person or property) 3. Property-rights dispute 4. Trespass - contamination of third-party natural resources 5. Trespass - infringement on third-party pore space 6. Breach of duty - leakage sufficient to undermine the value of carbon credits 7. Frivolous lawsuits private or organizational based legal challenges 8. Surface ownership and associated liability 9. Assigning liability responsibility in a multi-party project	Liability for potential damages associated with sequestration or operational aspects could preclude the project from moving forward. Property-right disputes over surface rights, mineral rights or pore space could halt or restrict construction, CO2 injection or monitoring operations for CCS projects. Under environmental, health and safety laws and regulations the owner/operator could be liable for: 1. Personal injuries 2. Property and natural resource damages 3. Oil spills and releases or discharges of hazardous materials 4. Well reclamation costs 5. Remediation and clean-up costs and other government sanctions and fines. 6. Other environmental damages 7. Additional reporting permitting or other issues arising from emissions of greenhouse gases and other regulated air pollutants.

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355	**17.03.01.**	Insurance	There are many kinds of insurance coverage. Some of those that pertain to CCS include: 1. Physical damage 2. Machinery breakdown 3. Business interruption (advanced loss of profit) 4. Environmental 5. Third-party liability 6.Worker's compensation 7. Transportation 8.Closure and post-closure financial assurance 9. Operator's extra expense (OEE)	Insurance coverage may not be available for CCS projects until there is a sufficient track record of performance (or failure) to determine the probability of failure occurring.
356	**17.03.02**	Transfer of long-term liability stewardship	Public companies cannot take on long-term liability for 50 years or more. There is no guarantee companies will stay in business that long. Therefore, it is up to a government entity to take on responsibility. The federal government would be preferred because it would level the playing field among states and spread the risks over more projects. A sinking fund could be used to cover the costs of such a program.	Companies are unlikely to invest in deep saline aquifer (DSA) sequestration projects without some assurance that the long-term liability is transferable or manageable.
357	**18.00.00.**	**CO2 CAPTURE RISKS**		
358	**18.01.00.**	CO2 capture system performance	Performance risks for CO2 capture systems could include: 1. Production below design capacity 2. Unable to meet product specification 3. Low CO2 recovery 4. Low thermal efficiency - greater heat losses than expected, low heat recovery 5. Excess solvent or sorbent consumption 6. Excess power consumption 7. Excess steam consumption 8. Excess cooling water circulation required 9. Excess maintenance 10. Low process availability 11. Low mechanical availability	Poor performance of the CO2 capture system can result in higher operating and maintenance costs, interruption of CO2 supply, and/or off spec CO2.

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359	**18.02.00.**	CO2 capture system design	Design deficiencies for CO2 capture systems could include: 1. Scale-up errors 2. Equipment undersized/oversized for proper residence time 3. Equipment undersized/oversized for proper surface area 4. Excess velocities 5. Inadequate expansion joints 6. System bottlenecks 7. Inadequate instrumentation 8. Inadequate process controls and alarms 9. Inadequate computer simulation models 10. Wrong sorption model for the contacting devise 11. Insufficient winterization 12. Wrong materials of construction 13. Lack of emergency flare/vent 14. Lack of surge capacity 15. Lack of redundancy -backup systems	Design deficiencies can result in poor performance, higher operating and maintenance costs, interruption of CO2 supply, and/or off-spec CO2..
360	**18.03.00.**	CO2 capture system scale up limitations	The limits on scale up of the CO2 capture system could include: 1. Equipment size limits - manufacturing, transport, or structural load limits 2. Heat transfer limits 3. Mass transfer limits 4. Diffusion limits 5. Surface area limits 6. Reaction kinetics limits	Limits in scale up of the CO2 capture system can lead to higher capital cost and higher operating costs.
361	**18.04.00.**	CO2 capture system operations	System operating risks for CO2 capture systems could include: 1. Non-equilibrium or non-steady-state conditions 2. Exothermic reactions overheating the process 3. Endothermic reactions overcooling the process 4. Pressure/stress buildup 5. Non-uniform mass distribution/dispersion/mixing – dead zones, stratification 6. Non-uniform temperature distribution – hot/cold spots, stratification 7. Mass and energy imbalance 8. System imbalance 9. Pressure or temperature cycling 10. System upset – unexpected high flow rate/temperature, carryover of upstream contaminants 11. Off-spec or inconsistent feed and/or product 12. Abrasion/erosion 13. Corrosion 14. Fouling 15. Contactor plugging 16. CO2 escape/leakage to the atmosphere 17. Scale build up causing heat exchanger failure 18. Air leakage - nitrogen dilution 19. Equipment failure due to defects, plugging, wear 20. Control system failure	Operation and maintenance problems can result in higher operating and maintenance costs, CO2 supply interruptions and off-spec CO2.

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362	**18.05.00.**	CO2 capture solvent or sorbent	Solvent or sorbent risks for CO2 capture could include: 1. Off-spec or inconsistent solvent or sorbent 2. Unexpected contamination (SOx, NOx, Cl, H2O, hydrocarbons, trace metals, chemical slip, particulate matter) 3. Gradual buildup of contaminants in circulating loads 4. Foaming 5. Chemical reactions with contaminants - precipitation of solids 6. Excess viscosities 7. Chemical degradation of solvent or sorbent 8. Thermal degradation of solvent or sorbent 10. Aging (deactivation) of solvent or sorbent 11. Hazardous material handling	Off spec or degraded solvent or sorbent can result in poor CO2 capture, higher operating costs, CO2 supply interruptions, and off-spec CO2.
363	**19.00.00.**	**CO2 DEHYDRATION RISKS**		
364	**19.01.00.**	CO2 dehydration system performance	Performance risks for CO2 dehydration systems could include: 1. Production below design capacity 2. Unable to meet product specification 3. Excess glycol consumption 4. Carryover of glycol into downstream systems 5. Excess utility consumption 6. Excess maintenance 7. Low plant process and/or mechanical availability	Poor performance of the CO2 dehydration system can result in higher operating and maintenance costs, interruption of CO2 supply, off spec CO2, and corrosion of downstream systems.
365	**19.02.00.**	CO2 dehydration system operation	Operating risks for CO2 dehydration systems could include: 1. Upset conditions 2. Foaming in the contactor 3. Fouling 4. Buildup of liquid contaminants in recycled glycol 5. Buildup of solid contaminants in recycled glycol 6. Contactor plugging due to fouling 7. Reboiler tube failure due to fouling 8. Heat exchanger failure due to fouling 9. Pump seal failure due to fouling 10. Corrosion - wrong materials of construction 11. Oxidation degradation of glycol 12. Thermal degradation of glycol Dehydration units are normally fairly reliable as long as they are maintained properly avoid process upsets and/or contamination.	Operating problems in the CO2 dehydration system can result in higher operating and maintenance costs, interruption of CO2 supply, off spec CO2, and corrosion of downstream systems.
366	**20.00.00.**	**CO2 COMPRESSION RISKS**		
367	**20.01.00.**	CO2 compression system performance	Performance risks for CO2 compression systems could include: 1. Output below design capacity 2. Unable to meet pressure specification 3. Excess power consumption 4. Excess maintenance 5. Low mechanical availability	CO2 operating performance is critical to success of a CCS project.
368	**20.02.00.**	CO2 compression system EPC	Engineering, procurement and construction (EPC) risks for compression systems could include: 1. Procurement delays - Compressors are typically one of the longest lead items for equipment 2. High capital cost - compression systems are one of the major capital costs for CCS projects 3. Improper specification 4. Metallurgical defect	Delays in project startup. Increased capital cost. Operating problems resulting from improper specification or installation.
369	**20.03.00.**	Compressor type	1. Reciprocating compressors - lower capital, higher maintenance, may require spare capacity 2. Centrifugal compressors - higher capital, lower maintenance 3. Screw compressors (dry type)	Type of compressors selected can impact capital costs, operating costs and operating availability.

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370	**20.04.00.**	Compression system operation	Operating risks for CO2 compression systems: 1. Improper operation - Intermittent operation of the compressor - Operating above/below recommended limits - Upset conditions - Operating compressor with control valve closed - Fouling by dust or liquid droplets - Plugging relief valves during depressurization - Corrosion - due to water in CO2 stream 2. Improper maintenance - Vibration - Noise - Overheating - Leakage 3. Wear and failure - Rod drop due to ring wear on recip. comp. - Rod run out or rod deflection on recip. comp. - Valve failure on recip. comp. - Bearing wear/failure - Tip wear on cent. comp	Downtime, loss of revenue, increased maintenance costs.
371	**21.00.00.**	**CO2 PIPELINE RISKS**		
372	**21.01.00.**	**Pipeline routing risks**		
373	**21.01.01.**	New versus existing right-of-way (ROW)	ROW issues include: 1. Single or multiple pipeline rights 2. Width of ROW 3. Rights for above ground facilities 4. Access to site for repair/modification and inspections 5. Payment for original and continued use of ROW 6. Damage awards for the property owner 7. Requirement for pipeline removal upon abandonment of the pipeline. 8. Eminent domain - used as a last resort to gain access to ROW	Developing a new ROW is significantly more riskier than using an existing utility ROW.
374	**21.01.02.**	Climate conditions	Weather conditions can impact pipeline surface facilities 1. Severe high or low temperatures 2. Significant winds (tornadoes) 3. Lightning - common cause of pipeline damage 4. Heavy rain fall - flooding 5. Severe winter storms	Delays in construction and damage to surface facilities.
375	**21.01.03.**	Soil and terrain conditions	1. Thin soil - insufficient to bury pipeline to depth 2. Corrosive soil - high moisture, high electrical conductivity, high acidity, and high dissolved salts 3. Rocky soil - special care needed in backfilling to protect pipeline 4. Unstable land - subsidence - uplift - landslides - earthquake area - active fault zone - high erosion areas - flood plains, dry wash - permafrost - frost heaves - high water table (marshes, swamps, peat bogs) - moving sand dunes - underground mine/coal mine areas - steep slopes >18% (landslides or erosion) 5. Rugged terrain/topography - mountains, hills, canyons, gorges 6. Significant elevation increase or variation over length of pipeline 7. Low lying areas 8. Exposed granite bedrock	1. Need to add soil to achieve 1.2 -1.8 m (4-6ft) burial depth 2. Accelerated external corrosion 3. Need fine backfill to protect pipeline 4. Can lead to unintended movement or abnormal loading of a pipeline resulting in mechanical damage, leakage or rupture. 5. Significantly higher installation cost 6. Increased compression or pumping costs due to higher pressure drop across pipeline 7. Potential for leaked CO2 to accumulate in low lying areas if there is insufficient escape velocity or wind to disperse the leaked CO2 to the atmosphere. 8. Very high costs for blasting a pipeline trench

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376	**21.01.04.**	Populated areas	A high population area means an urbanized area, as defined by the Census Bureau, that contains 50,000 or more people and has a population density of at least 1000 people per square mile. This is designated a high consequence area. (49 CFR Part 195.450) Other populated areas are also designated as high consequence areas. Non rural areas categorized as high risk. Rural areas categorized as low risk. (49 CFR Part 195 Appendix B) Pipeline right-of-way must be selected to avoid, as far as practicable, areas containing private dwellings, industrial buildings, and places of public assembly. No pipeline may be located within 15 m (50 feet) of any private dwelling, or any industrial building or place of public assembly in which persons work, congregate or assemble, unless it is provided with at least 0.3 m (12 inches) of cover in addition to that prescribed in Section 195.238 (49 CFR Part 195.210). CO2-CRC recommends a 30 m (100 ft) wide easement restricting access to the buried pipeline, a distance of 100 m (330 ft) minimum distance from residential buildings and a 1,000 m (3,300 ft) consultation zone on either side of the pipeline for emergency notification. 1. High population density nearby 2. Sensitive receptors (schools, hospitals, nursing homes, prisons) nearby 3. Business/industry/mining nearby	The greater the number of people, the greater the risk of exposure to CO2.
377	**21.01.05.**	Land crossings	1. Navigable water ways - Army Corp of Engineers permitting 2. Protected areas - Wetlands, migratory water bird concentration, national parks, habitats for imperiled, threatened, endangered or protected species (aquatic and terrestrial), archeological sites. (49 CFR Part 195.6) 3. Federal land - could trigger the need for permits from the US Army Corp of Engineers, the US Fish and Wildlife, the US Department of the Interior Bureau of Land Management (BLM), the US Department of Agriculture, Forest Service, the US Department of Defense. Also will trigger the National Environmental Policy Act (NEPA) and require Environmental Assessment (EA) or Environmental Impact Statement (EIS) 4. Tribal land - would trigger NEPA (EA or EIS) and the need for a permit from the US Department of Interior Bureau of Indian Affairs (BIA) 5. Transportation corridors - Railroads, highways, roads, bridges, other rights of way could trigger the need for permits from railroad companies, state/county departments of transportation. 6. Drinking water resource areas - 7. Non navigable surface waters - lakes, rivers, streams	Land crossing increase cost and the need for additional permits.
378	**21.01.06.**	Offshore pipeline	The difficulty of offshore construction is roughly proportional to the depth multiplied by the pipeline diameter. (IPCC 2005). Some of the risks include: 1. Sea currents 2. Uneven seabed 3. Biological growth on pipeline 4. Arctic conditions (ice gouging)	Offshore pipeline have significantly higher costs.
379	**21.02.00.**	**Pipeline design risks**		
380	**21.02.01.**	Pipeline diameter	1. Large diameter Large diameter pipelines will release more CO2 in a rupture and are thus classified as having greater severity in the case of a failure such as a rupture. 2. Insufficient diameter for capacity Increased pressure required may place too much stress on the pipeline and components. Limits future expansion. 3. Excess diameter for capacity Resulting decreased pressure may put the CO2 at risk of changing from supercritical to two-phases. No room for	High risk: Pipeline diameter 0.46 m (18 in) and above. Medium risk: Pipeline diameter from 0.25-0.4 m (10 to 16 in). Low risk: Pipeline diameter 0.2 m (8 in) and below. (49 CFR Part 195 Appendix B.
381	**21.02.02.**	Pipeline length	The longer the pipeline, the greater the risks.	Long pipeline more expensive, more potential for failure.
382	**21.02.03.**	Pipeline failure history (for existing pipeline)	Pipeline failure history for time-dependent defects can indicate probability of future failures.	High risk: >3 leaks in last 10 years. Low risk: ≤3 leaks in last 10 years. (49 CFR Part 195 Appendix B)

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383	**21.02.04.**	Pipeline age (for existing pipeline)	Safety risk increases with the age of the pipeline depending on the pipeline's coating and corrosion condition, and steel quality, toughness, welding.	High risk: >25 years old Low risk: <25 years old (49 CFR Part 195 Appendix C)
384	**21.02.05.**	Pipeline pressure	All pipeline components must be designed and tested for at least 125% of maximum operating pressure (MOP). If, within a pipeline system, two or more components are to be connected at a place where one will operate at a higher pressure than another, the system must be designed so that any component operating at the lower pressure will not be overstressed. (49 CFR Part 195.104) Pipelines should be designed with sufficient pressure to maintain CO2 as a supercritical fluid. 1. Operating pipeline in excess of maximum operating pressure (MOP). 2. Operating pipeline below the CO2 supercritical pressure (CSP). 3. Insufficient working range between MOP and CSP.	Components operating at excessive operating pressure will be overstressed and subject to failure. Operating the pipeline at or below the supercritical pressure of CO2 can lead to CO2 phase change in the pipeline. If the supercritical CO2 drops back into the liquid-vapor, two-phase region (which occurs below 6.9 MPa (1000 psig) at ambient temperature), there would be freeze-up issues and a much higher pressure drop in the pipeline.
385	**21.02.06.**	Pipeline external loads	Anticipated external loads (e.g.), earthquakes, vibration, thermal expansion, and contraction must be provided for in designing a pipeline system. (See ASME B31.4). The pipe and other components must be supported in such a way that the support does not cause excess localized stresses (49 CFR Part 195.110). The pipe at each railroad and highway crossing must be installed so as to adequately withstand the dynamic forces exerted by anticipated traffic loads (49 CFR Part 195.256).	Insufficient design for external loads could lead to cracking and CO2 leakage.
386	**21.02.07.**	Pipeline wall thickness	Thicker pipe is typically used for sensitive areas like crossings. Wall thickness for 0.3 -0.36 m (12-14 in) pipe is typically 9.5 mm (0.375 in) except in sensitive areas like crossings where 12.7 mm (0.5 inch) wall thickness used for road crossings (up to 0.3 m (1 ft) past road right of way) and 15.9 mm (0.625 in) thickness used for railroad crossings. (DGC)	Thicker walls give a better safety margin.
387	**21.02.08.**	Pipeline steel grade	X65 carbon steel is typically used for CO2 pipeline if CO2 is dry and has low impurities such as H2S.	Pipeline steel grade determines pipeline maximum operating pressure
388	**21.02.09.**	Pipeline temperature	CO2 increases in temperature as it is compressed and decreases in temperature as it expands. CO2 entering a pipeline may be in the range of 49°C (120°F) however, it will gradually conform to the ambient ground temperature which may be in the range of 10°C (50°F). Components of CO2 pipelines that are subject to low temperatures during normal operation because of rapid pressure reduction or during the initial fill of the line must be made of materials that are suitable for those low temperatures. (49 CFR Part 195.102)	Improper material selection for pipeline components that may experience extreme cold due to rapid pressure reduction may result in component failure and CO2 leakage.
389	**21.02.10.**	Piping type	Seamless pipe is typically used for sensitive areas like crossings or near residences; double submerged arc welded or electric resistance welded pipe is typically used for other areas. (DGC)	Proper piping selection is important in sensitive areas to prevent risk of CO2 leakage.

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390	**21.02.11.**	Pipeline coating	CO2 pipelines are typically coated with fusion bonded epoxy to prevent corrosion. In addition piping used at bored crossings is overcoated with an abrasion resistant coating to prevent damage to the epoxy coating during installation. (DGC) 1. External coating 2. Internal coating	Damage to pipeline coating during installation or due to third-party excavation can result in external corrosion.
391	**21.02.12.**	Pipeline cathodic protection	Cathodic protection on CO2 pipelines is maintained by rectifiers located at main-line valve stations every 32 km (20 miles) or less along the pipeline. Cathodic protection is measured in voltage at test posts located at 1.6 km (1 mi) intervals over the length of the pipeline. The rectifier output is adjusted to maintain voltage levels between 0.85 and 1.4 volts at each test station. (DGC)	Insufficient or lack of cathodic protection could lead to external corrosion and CO2 leakage.
392	**21.02.13.**	Pipeline booster stations or pumping stations	Booster or pumping stations are typically needed every 80-320 km (50 to 200 mi) depending on end-use pressure (EERC). Adequate ventilation must be provided in pumping station buildings to prevent the accumulation of CO2 gas, Warning devices must be installed to warn of the presence of CO2 gas in the pumping building. Safety devices to prevent over pressuring of primary and auxiliary pumping equipment and a device for emergency shutdown of each pumping station should be included. If power is necessary to actuate the safety devices, an auxiliary power supply should be included. (49 CFR Part 195.262)	Insufficient booster or pumping stations could lead to low pressure at the end of the pipeline.
393	**21.02.14.**	Pipeline future expansion	If there is potential for future expansion, it is practical to install taps for future branches, leave room for booster stations and design the pipeline to allow for expansion at higher pressure without having to replace piping and components. Pipeline diameter and pressure should take into account potential for future expansion through addition of booster stations and increased operating pressure.	Lack of reserved locations for booster stations, insufficient pipeline diameter, and excess operating pressure may make future expansion of pipeline capacity more difficult and more expensive.
394	**21.02.15.**	Pipeline flow velocity	Reported pipeline velocity varies from 0.9 to 4.6 m/s (3 to 15 ft/s). (IPCC 2005)	Excessive flow capacity could cause erosion in pipeline components.
395	**21.02.16.**	Pipeline SCADA system	Supervisory control and data acquisition (SCADA) system should have sufficient instrumentation for the central control room to monitor and control flow along the entire pipeline. The system should have built in redundancies to prevent loss of operational capability if a component fails. 1. IT security for SCADA system to protect against cyber-terrorism	Loss of the SCADA system could shut the pipeline down or result in pipeline failure and CO2 release.
396	**21.02.17.**	Pipeline CPM leak detection systems	Computational pipeline monitoring (CPM) leak detection system must comply with section 4.2 of API 1130. (49 CFR Part 195.134). CPM leak detection can be based on acoustics, measurement of chemical release, detecting pressure changes or small changes in mass balance.	Lack of a properly designed CPM leak detection system prevents the pipeline operator from rapid detection and response to CO2 leaks. Inaccurate modeling of CO2 dense phase can cause the computational leak detection system to malfunction.

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397	**21.02.18.**	Pipeline block valves or control valves	Main-line valves (block or control valves) are located on either side of water crossings and approximately every 32 km (20 mi) overland in order to allow for quick isolation and to minimize the impact of a leak. (DGC) Valves must be installed at each of the following locations: on the suction end and discharge end of a pump station, on each mainline at locations along the pipeline system that will minimize damage or pollution from CO_2 discharge, on each lateral takeoff from the trunk line, on each side of a water crossing that is more than 30 m (100 ft) wide and on each side of a reservoir that is holding water for human consumption. (49 CFR Part 195.260) Each valve must be installed in a location that is accessible to authorized employees and that is protected from damage or tampering. (49 CFR Part 195.258)	The distance between main-line valves determines the amount of CO_2 released in a rupture. Longer spacing means a larger volume of CO_2 is likely to escape.
398	**21.02.19.**	Pipeline internal inspection devices	Pipelines must be designed and constructed to accommodate the passage of instrumented internal inspection devices (i.e. smart pig). 49 CFR Part 195.120) No operator may use a launcher or receiver that is not equipped with a relief device capable safely relieving pressure in the barrel before insertion or removal of scrapers or spheres. (49 CFR Part 195.426)	Internal inspection devices are important tools for detecting corrosion or mechanical damage in pipelines before they fail.
399	**21.02.20.**	Pipeline seals	Teflon or nylon have been used for seals to prevent swelling. (Meyer 2007).	Improper sealing materials may react with CO_2 and cause CO_2 leakage
400	**21.02.21.**	Pipeline winterization	Winterization (protection from severe cold/ice) may be needed for above ground facilities in cold climates.	Lack of winterization can cause CO_2 pipeline instrumentation lines and valves to freeze up in severe cold/icy weather.
401	**21.02.22.**	Pipeline burial depth	CO_2 pipelines are typically buried a minimum of 1.2 m (4 ft) over the length of the pipeline, ≥1.5 m (5 ft) below roads, ≥3 m (10 ft) below railroads, ≥1.2 m (4 ft) below ditches and ≥3 m (10 ft) below water line on shores. (DGC). Minimum burial depth for pipeline is 0.9 m (36 in) for industrial commercial and residential areas, 1.2 m (48 in) for crossing of inland bodies of water, 0.9 m (36 in) for drainage ditches at public roads and railroads, 1.2 m (48 in) for deepwater port safety zones, 0.9 m (36 in) for offshore areas and 0.8 m (30 in) elsewhere. There are exceptions for rock excavation areas. (49 CFR Part 195.248)	Insufficient burial depth makes pipeline more susceptible to excavation damage, sabotage, climate damage etc.
402	**21.02.23**	Pipeline bedding and foundation structures	Pipeline bedding and foundation structures are designed to hold a pipeline stable throughout its life. This is particularly important for offshore pipelines.	Improper design of pipeline bedding or foundation structures could result in pipeline shifting or buckling.
403	**21.03.00.**	**Pipeline defects**		

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404	**21.03.01.**	Pipeline material defects	During the manufacturing of steel, impurities can sometimes remain in the molten steel. These impurities can cause an incomplete bonding of the material in the steel plate or solid round billet used to produce pipe and other pipeline components. reduce the wall thickness of the pipe or pipeline component, and, if large enough, can reduce the pressure-carrying capacity of the pipe or component. Some pipeline material defects include: 1. Propagating cracks - very rapid propagating cracks can occur that "unzip" the pipeline along its length. 2. Laminations and inclusions - caused by oxides or impurities trapped in the steel 3. Blisters and scabs - raised spots on steel surface caused by expansion of trapped gases within the steel 4. Hard spots - created by localized cooling of the steel plate (ERW pipe) during rolling 5. Indentations - formed by the expanders or mandrels used to make seamless pipe 6. Transit fatigue - cracks formed when pipes are repeated flexed during transportation and handling 7. Cyclic fatigue - cracks caused by stress from repeated fluctuating operating pressure within the pipe 8. Elastomer and polymer - failure due to reaction with CO2	1. Propagating cracks can lead to pipeline rupture. 2. A lamination or inclusion can eventually lead to failure if they eventually grow to the inner or outer wall of the pipe or pipeline component through pressure cycles. 3. Blisters and scabs reduce the wall thickness of the pipe and, if large enough, can reduce the pressure-carrying capacity of the pipe or component. 4. Cracking can occur at hard spots that eventually grows in size over time. 5. Stress risers can occur at indentations if they are too deep, eventually leading to pipe failure. 6. Transit fatigue cracks are typically discovered during the hydrostatic pressure testing however, some can remain and grow during pipeline pressure cycles until a failure occurs. 7. Can lead to CO2 leakage. 8. Failure of elastomers and/or polymers could lead to CO2 leakage.
405	**21.03.02.**	Pipeline weld defects	Some pipeline weld defects include: 1. Pinholes - small, unwelded area extending through the entire thickness of the weld 2. Toe cracks - occur where the crown of the weld bead intersects the edge of the plate in pipe joined using the Double Submerged Arc Welding (DSAW) 3. Off seam welding - crack caused by the inside and outside welds of the DSAW process being offset 4. Undercutting - occurs when there is an inadvertent reduction in the wall thickness in the area of the weld 5. Incomplete fusion - occurs when there is a lack of complete fusion of the weld and the base metal 6. Porosity - occurs when one ore more voids are created in the weld material from shrinkage of the material 7. Slag inclusions - exist when non-metallic material becomes trapped in the weld 8. Weld defects in older pipe - Burnt pipe edges - Incomplete fusion - Hook cracks - Cold welds	Weld defects can lead to CO2 leakage
406	**21.03.03.**	Pipeline equipment defects	Equipment failures involve pumps, compressors, valves, meters, tanks, control/relief equipment and other components and devices on pipeline systems. (PHMSA). Can include broken couplings, stripped threads.	Equipment is often located on company property that is not accessible to the public. Equipment failure usually results in a CO2 release that is contained on public property, typically not resulting in injury to the general public. (PHMSA)
407	**21.04.00.**	**Pipeline corrosion**	About 15% of gas pipeline failures in Europe are caused by corrosion (EGIG 2008)	Corrosion can lead to pipe failure and CO2 leakage.
408	**21.04.01.**	External corrosion	Galvanic corrosion can take place when an unprotected metal pipeline comes in contact with water or soil. 1. External corrosion of buried pipe 2. External corrosion of surface pipe	Corrosion can lead to pipe failure and CO2 leakage.

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409	**21.04.02.**	Internal corrosion	There is potential for rapid corrosion of steel pipeline if free water becomes present in the CO2 stream. There is currently insufficient data to adequately understand the effect of an accidental flow of high water content CO2 into a pipeline and also the influence the various CO2 impurities (O2, H2, SOx, NOx, H2S TEG, MEG and amines/NH3) will have on the corrosion rates. (DNV CO2PIPETRANS Phase 2). Corrosion rate of carbon steel in dry supercritical CO2 is low. For AISI 1080 values around 12.5 microns per year have been measured at 9-12 MPa (90-120 bar) and 160-180°C for 200 days. During 12 years, the corrosion rate in an operating pipeline amounted to 0.25-2.5 microns per year.	Corrosion can lead to pipe failure and CO2 leakage.
410	**21.04.03.**	Microbial corrosion	Microbial corrosion is corrosion promoted by microorganisms such as chemoautotrophs which can produce hydrogen sulfide, sulfuric acids, other acids or ammonia. Some bacteria directly oxidize iron to iron oxide or iron hydroxide.	Hydrogen sulfide can cause corrosion and sulfide stress cracking.
411	**21.04.05.**	Selective seam corrosion	Selective seam corrosion (SSC) is a form of corrosion that tends to affect pipe manufactured prior to 1970 using low-frequency electric resistance welding (LR-ERW) or electric flash welding (EFW) processes. SSC is a localized corrosion attack along the weld bond line of ERW and EFW pipe, that leads to the development of a wedge shaped groove that is often filled with corrosion products. (PHMSA)	Risk for older LF-ERW or EFW pipe, not HF-ERW, DSAW or seamless pipe. (PHMSA)
412	**21.0404.**	Stress corrosion cracking	Stress corrosion cracking (SCC) is a form of corrosion that produces a marked loss of pipeline strength with little metal loss. The combined influence of pipeline stress due to its pressurized contents and a corrosive medium can occasionally result in the formation of interlinking crack clusters that can grow until the affected pipe fails. (PHMSA)	Stress corrosion cracking can result in pipe failure and CO2 leakage.
413	**21.05.00.**	**Pipeline mechanical damage**	Mechanical damage consists of dents, gouges, cracks, punctures, stress risers or ruptures.	Mechanical damage of a pipeline can lead to immediate or eventual/accelerated CO2 leakage.
414	**21.05.01.**	Excavation damage	About 50% of pipeline failures in Europe and 33% in the US are caused by excavation damage. Excavation damage can include damage to the external coating of the pipe, or dents, scrapes, cuts, or punctures directly into the pipeline itself. The damage can be caused by any type of excavation, including digging, grading, trenching and boring, road and highway maintenance, general construction and farming activities. It normally occurs when excavators fail to call their local one-call system to mark where underground facilities are located prior to excavating. (PHMSA)	Excavation can lead to pipeline damage and CO2 leakage.
415	**21.05.02.**	Natural force damage	Natural force damage includes damage from landslide, flood, heavy rains, riverbed scouring and washouts, dike breaks, subsidence, earthquakes, high winds, tornadoes, hurricanes, lightning, frost heaves, and frozen instrumentation lines. (PHMSA)	Can lead to unintended movement or abnormal loading of a pipeline resulting in mechanical damage, leakage or rupture.
416	**21.05.03.**	Other outside force damage	Other outside force damage excludes excavation but include such things as vehicle accident (hitting above ground valve or booster station), electric arcing from nearby power lines, vandalism, sabotage, terrorist attack, theft, fires from other businesses or industries, etc. (PHMSA) Most susceptible to this particular type of damage are above ground pipeline facilities which are in close proximity to highways or large population and industrial centers.	Mechanical damage of a pipeline can lead to immediate or eventual/accelerated CO2 leakage.

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417	**21.05.04.**	Mechanical damage requiring immediate repair	Metal loss greater than 80% of nominal wall thickness. Dent located on the pipeline (above 4 and 8 o'clock positions) that has any indication of metal loss, cracking or a stress riser. Dent located on the pipeline (above 4 and 8 o'clock positions) with a depth greater than 6% of the nominal pipe diameter. (49 CFR Part 195.452)	Mechanical damage can require immediate repair to prevent CO2 leakage.
418	**21.05.05.**	Mechanical damage requiring evaluation and remediation within 60 days of discovery	Dent on the bottom of the pipeline that has any indication of metal loss, cracking or a stress riser. Dent located on the pipeline (above 4 and 8 o'clock positions) with a depth between 3% and 6% of the nominal pipe diameter. (49 CFR Part 195.452)	Mechanical damage can require timely evaluation and remediation to prevent CO2 leakage.
419	**21.06.00.**	**Pipeline procurement risks**		
420	**21.06.01.**	Used pipe or old pipe	Used pipe must comply with the same quality requirements as new pipe. Used pipe must not have any mechanical damage (buckles, cracks, gouges, dents) or corroded areas that threaten the integrity of the pipe. (49 CFR Part 195.114).	Use of defective used pipe could result in pipe failure and CO2 leakage.
421	**21.06.02.**	Pipeline valves	Each valve must be of sound engineering design, compatible with pipe and fittings, successfully hydrostatically tested, clearly marked for open and closed positions (except check valves), properly marked (nameplate) and properly sized. (49 CFR Part 195.116)	Defective or off-spec valves could result in valve failure and CO2 leakage. Wrong sized valves could lead to additional pressure stress or failure.
422	**21.06.03.**	Pipeline fittings	Fittings must be suitable for the intended service and be at least as strong as the pipe and other fittings in the pipeline system. There may not be any buckles, dents, cracks, gouges or other defects in the fittings that may reduce the strength of the fitting. (49 CFR Part 195.118)	Defective off-spec fittings could result in fitting failure and CO2 leakage.
423	**21.06.04.**	Other pipeline components	Other components such as fabricated branch connections, closures, flange connections, station piping, and fabricated assemblies must meet applicable requirements. (49 CFR Part 195122-195.130) Materials for bolts and nuts should be same as flange. At least one full thread of bolt should be exposed beyond the nut. Gasket material should be compatible with CO2.	Defective or off-spec pipeline components could result in component failure and CO2 leakage.
424	**21.07.00.**	**Pipeline construction defects**	About 16% of gas pipeline failures in Europe are caused by construction defect or material failure. (EGIG 2008)	Construction defects could result in pipeline failure and CO2 leakage.
425	**21.07.01.**	Pipe installation	All pipeline installed in a ditch must be installed in a manner that minimizes the introduction of secondary stresses and the possibility of damage to the pipe. (49 CFR Part 195.246). This is of particular concern in rocky soil. When a ditch for a pipeline is backfilled, it must be done in a manner that provides firm support under the pipe, and prevents damage to the pipe and pipe coating from equipment or from the backfill material. (49 CFR Part 195.252) Pipeline coating can be damaged during installation by laying the pipeline on sharp rocks in the ditch, dropping rocks on it during backfill, rough contact with equipment or abrasion if installing pipe through a bored hole under a road or railroad crossing.	Pipe damage during installation could result in accelerated pipe failure and CO2 leakage Significant incident rate due to equipment/material/weld failure based on PHMSA CO2 pipeline data from 1986 - July 2012: 1.34E-04/mile/yr.
426	**21.07.02.**	Valve and other equipment installation	Valves and other equipment must be properly seated and installed.	Valves that are not properly seated or improperly installed could lead to system failure.

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427	**21.07.03.**	Pipe bending	Pipe must not have a wrinkle bend. A bend must not impair serviceability of the pipe. Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage. On pipe containing a longitudinal weld, the longitudinal weld must be as practicable to the neutral axis of the bend unless the bend is made with an internal bending mandrel or the pipe is 0.32 m (12.75 in) or less nominal outside diameter or has a diameter to wall thickness ratio less than 70. Each circumferential weld which is located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process. (49 CFR Part 195.212)	Pipe damage during bending could result in accelerated pipe failure and CO2 leakage
428	**21.07.04.**	Pipe welding (**See 21.03.02.)**	Welding must be performed by a qualified welder in accordance with welding procedures qualified under Section 5 of API 1104 or Section IX of the SASME Boiler and Pressure Vessel Code. Each welding procedure must be recorded in detail, including the results of the qualifying tests. 49 CFR Part 195.214-195.234)	Improper welding procedures could result in CO2 leakage.
429	**21.07.06**	Pipeline underground clearance	Any pipe installed underground must have at least 0.3 m (12 in) of clearance between the outside of the pipe and the extremity of any other structure, except that for drainage tile. (49 CFR Part 195.250).	Insufficient clearance could cause mechanical damage under load.
430	**21.07.07.**	Pipeline integrity inspection	No pipe or other component may be installed in a pipeline system unless it has been visually inspected at the site of installation to ensure that it is not damaged in a manner that could impair its strength or reduce its serviceability. (49 CFR Part 195.206)	Improper or lack of integrity inspection may fail to discover mechanical damage or defects before CO2 is fed to the pipeline.
431	**21.07.08.**	Protection for above ground components	Above ground components may be installed in areas under direct control of the operator but should be inaccessible to the public. (49 CFR 195.254)	Insufficient protection for above ground components could lead to vandalism, theft and equipment damage by third parties.
432	**21.07.09.**	Construction records	A complete record must be maintained by the operator for the life of each pipeline facility of girth welds (total, number tested, rejected, disposition), pipe installed (amount, location cover, size), locations of pipeline crossings, utility crossings, overhead crossings, valves, and corrosion test stations. (49 CFR Part 195.266) 1. Lack of final as-built drawings 2. Pipeline location not properly documented 3. Valves and other equipment not properly marked	Incomplete or inaccurate construction records or as-built drawings could result in error or confusion during operation, maintenance or emergency response. Improper documentation of pipeline location can lead to confusion when marking a pipeline location prior to excavation. Failure to properly mark valves and other equipment could lead to improper opening or closing of valves or improper equipment operation and/or maintenance.
433	**21.08.00.**	**Pipeline operation risks**		
434	**21.08.01.**	Operator error in pipeline operation	Operator error can include: 1. Leaving the wrong valve open or closed 2. Not following proper procedures 3. Using improper equipment or techniques to affect a repair 4. Improperly assessing a situation or condition resulting in inappropriate actions or decisions	Potential for pipeline failure and CO2 leakage.
435	**21.08.02.**	Pipeline over pressuring	Maximum operating pressure (MOP) is limited to 80% of pipeline design pressure. Isolating pipework or facilities with dense phase CO2 can result in doubling the pressure from 10 to 20 MPa (100 to 200 bar) as temperature raises from 25°C to 40°C.	Isolation of pipeline sections could lead to pipeline over pressuring. Operating the pipeline above maximum operating pressure (MOP) could place the pipeline at risk for failure.
436	**21.08.03.**	Pipeline re-pressurization	Re-pressurizing a pipeline results in isenthalpic flash across the re-pressurizing valve causing low temperature in the pipeline, no solid CO2 formation if the CO2 is warm enough. (Anderson 2008).	Low temperature across the re-pressurizing valve

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437	**21.08.04.**	Pipeline depressurization	Rapid depressurization on blowdown of a pipeline can lead to low temperatures (isentropic behavior) and possible solid CO2 formation at pressures below 5 bar. (Anderson 2008).	Rapid depressurization of facilities can lead to CO2 hydrate formation in vent system, possibly causing blockage and over pressurization. (Anderson 2008). Solidification of CO2 could lead to plugging of relief valves. Lowering depressurization rate of a compressor can lead to asphyxiation risk. (Anderson 2008).
438	**21.08.05.**	Pipeline flow modeling	There is a need for improved understanding of the effect contaminants (O2, H2, SOx, NOx, H2S TEG, MEG and amines/NH3) have on the phase diagram and behavior of a CCS CO2 stream. (DNV CO2PIPETRANS Phase 2) Nitrogen and oxygen in CO2 will shift the boundary of the two-phase region toward higher pressures and would require a higher operating pressure to avoid two-phase flow.	Improper understanding of the impact of CO2 impurities on the phase diagrams could lead to inaccurate pipeline flow modeling. Inaccurate modeling can cause the computational leak detection system to malfunction.
439	**21.08.06.**	Boiling liquid expanding vapor explosion (BLEVE)	Boiling liquid expanding vapor explosion (BLEVE) is a type of explosion that can occur when a vessel or pipeline containing a pressurized liquid is ruptured. Such explosions can be extremely hazardous. A BLEVE results from the rupture of a vessel containing a liquid substantially above its atmospheric boiling point. The substance is stored partly in liquid form, with a gaseous vapor above the liquid filling the remainder of the container. If the vessel is ruptured — for example, due to corrosion, or failure under pressure — the vapor portion may rapidly leak, lowering the pressure inside the container. This sudden drop in pressure inside the container causes violent boiling of the liquid, which rapidly liberates large amounts of vapor. The pressure of this vapor can be extremely high, causing a significant wave of overpressure (an explosion) which may completely destroy the storage vessel and project fragments over the surrounding area. (Wikipedia)	Supercritical CO2 can have significant density variations with changes in pressure and temperature. If a pipeline ruptures, this could lead to a boiling liquid expanding vapor explosion (Anderson 2008).
440	**21.08.07.**	Pipeline scheduled maintenance	Typical scheduled maintenance jobs and frequency: Aerial patrols 26 times per year. Population density survey every other year. ROW inspection 26 times per year. Emergency systems tested annually. Rectifier maintenance completed 6 times per year. Cathodic protection survey annually, Internal inspection of pipeline using an electronic tool, every 5 years or more frequently if necessary. Overpressure safety devices checked annually. Public awareness and damage prevention program reviewed annually. (DGC). Inspect each mainline valve twice a year 1. Pipeline cleaning	Failure to properly inspect and maintain the pipeline could lead to pipeline failure and CO2 leakage.
441	**21.08.08.**	Pipeline malfunctions	Some pipeline malfunctions could include: 1. Equipment malfunction or failure 2. Unintended valve closure or shutdown 3. Loss of communication (SCADA system) 4. Power outage 5. Pig stuck in pipeline causing a shutdown	Pipeline malfunctions could lead to unintended shutdown or CO2 leakage.

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442	**21.08.09.**	Pipeline leak	Pipeline leaks can include: 1. Pinhole leak - small leak (visible due to dry ice forming on the surface) 2. Pipeline puncture small diameter leak 3. Pipeline puncture large diameter leak	CO2 leakage.
443	**21.08.10.**	Pipeline rupture	Pipeline ruptures consist of a circumferential or longitudinal propagation fracture	CO2 leakage.
444	**21.08.11.**	Pipeline safety measures	Pipeline safety measures can include: 1. Emergency response plan 2. Reverse 911 call system - emergency alert 3. One-call system - prior to drilling or excavating 4. Supervision of excavation near pipelines 5. Regular inspection and maintenance of pipeline and ROW 6. CO2 monitors and alarms at booster stations 7. Oxygen packs at booster stations 8. Fire fighting equipment at booster stations 9. Public emergency response plan 10. Fencing and barricades to protect above ground facilities 11. Markers for ROW, valves and equipment	Lack of pipeline safety measures could lead to human injury and/or pipeline damage.
445	**21.09.05**	Pipeline hydraulic testing	Except as otherwise provided in this section … no operator may operate a pipeline unless it has been pressure tested … without leakage, (49 CFR Part 195.300-195.310)	Improper or lack of hydraulic testing may fail to discover leaks before CO2 is fed to the pipeline.
446	**22.00.00.**	**CO2 ON-SITE FACILITIES RISKS**		
447	**22.01.00.**	On-site facilities for DSA	On-site facilities for deep saline aquifer (DSA) CO2 injection can include: 1. Injection CO2 distribution system trunk and laterals 2. Power supply 3. Injection and monitoring wells 4. Onsite CO2 pumping stations 5. Water treatment facilities.	Potential problems could include, blowout, equipment failure.

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CarbonSAFE Rocky Mountains Phase I, CO2-Storage Subsurface, Surface, Technical and Programmatic Risk Areas				
Line #	**Index #**	**Risk Area/FEP**	**Description**	**Relevance**
448	**22.02.00.**	On-site facilities for EOR	On-site facilities for CO_2 enhanced oil recovery (EOR) can include: 1. Recycle CO_2 compression system and building 2. Injection CO_2 distribution system trunk and laterals 3. Production gathering system 4. Oil, water and slop storage tanks 5. CO_2 dehydration system 6. CO_2 gas scrubber/knockout drum 7. Flare system 8. Circulation and transfer pumps 9. Instrument air system 10. Control room, motor control center and building 11. Power supply transformers, UPS, PLCs, cables 12. Injection, production, disposal and monitoring wells 13. Water treatment/disposal facilities 14. CO_2 separation and hydrocarbon recovery.	Potential problems could include blowout, oil leaks/spills ignition/explosion, equipment failure, water quality, water disposal
449	**22.03.00.**	On-site facilities for ECBM	On-site facilities for CO_2 enhanced coal bed methane (ECBM) can include: 1. Recycle CO_2 compression system and building 2. Injection CO_2 distribution system trunk and laterals 3. Production gathering system 4. Water storage tanks 5. CO_2 dehydration system 6. CO_2 capture system - removal of CO_2 from nat. gas 7. Flare system 8. Circulation and transfer pumps 9. Instrument air system 10. Control room, motor control center and building 11. Power supply transformers, UPS, PLCs, cables 12. Injection, production, disposal and monitoring wells 13. Water treatment/disposal facilities	Potential problems could include blowout, methane leaks ignition/explosion, equipment failure, water disposal.
450	**22.04.00.**	Injection well components	CO_2 injection well components generally include: 1. Wellhead and tree 2. Tubing and casing 3. Safety valve 4. Packer 5. Packer fluid 6. Elastomers 7. Perforations 8. Sand control - for unconsolidated reservoirs	Component failure could result in CO_2 leakage.

QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA)

CarbonSAFE Rocky Mountains Phase I, CO2-Storage Subsurface, Surface, Technical and Programmatic Risk Areas

Line #	Index #	Risk Area/FEP	Description	Relevance
451	**22.05.00.**	Injection well materials of construction	steel. Typical materials of construction for EOR CO2 injection wells include: - Upstream metering & piping runs: 316 SS, Fiberglass - Christmas tree (trim): 316 SS, Nickel, Monel - Valve packing and seals: Teflon, Nylon - Wellhead (trim): 316 SS, Nickel, Monel - Tubing hanger: 316 SS, Incoloy - Tubing: fiberglass lined (GRE) carbon steel, internally plastic coated carbon steel, corrosion resistant alloys - Tubing joint seals: Seal ring (fiberglass lined), coated threads and collars (internally plastic coated) - On/off tool, profile nipple: Nickel plated wetted parts, 316 SS - Packers: Internally coated hardened rubber of 80-90 durometer strength (Buna-N), Nickel plated wetted parts - Cements and cement additives: API cements and/or acid resistant specialty cements and additives - Production liner 316 SS, Incoloy - Casing: carbon steel J-55 and K-55 grades; corrosion resistant alloy used in intervals where potential potable water aquifers exist or where H2S is present (Meyer 2007) Elastomers - Teflon or nylon have been used to prevent swelling	Corrosion can occur when tubulars are exposed to wet CO2. Sufficient quantities of H2S in CO2 can cause corrosion or sulfide stress cracking. (CCP 2009) The reservoir fluid affects corrosivity near the wellbore and compaction resistance where formation dissolution has occurred. In significant dissolution cases, the well tubulars must be designed to resist column buckling in the injection interval. (CCP 2009) CO2 phase behavior can impact velocity. High velocity of injection can cause erosion to materials exposed to the CO2 stream (CCP 2009)
452	**22.05.01.**	Elastomer seals	Since supercritical CO2 is a solvent, many elastomers, plastics, rubber, or resins present in a well could be subject to chemical attack or dissolution. When designing a CO2 injector, material should be based on performance expectations. Elastomers, in particular, are a common part of well hardware used to seal different components. Elastomers must be made of material that is chemically compatible or inert to the injection fluid and must be of sufficient strength or adequately anchored to withstand the different pressure and explosive decompression that might exist across a seal, Since the physical and performance characteristics of many elastomer materials change with pressure and temperature, the elastomer must be able to perform reliably across the full range of differential pressures and temperatures expected through the design life of the well at the location of the seal within the well. (CCP 2009) Teflon or nylon have been used for seals to prevent swelling. (Meyer 2007).	Elastomer seal failure can result in CO2 leakage.
453	**22.06.00.**	Injection well safety precautions	Safety precautions for injection wells include: 1. Casing corrosion protection - Impressed and passive currents - Oxygen, biocide corrosion inhibiting chemicals 2. Gentle handling to prevent damage to tubing coatings 3. Casing leak detection testing 4. Fencing, monitoring and atmospheric dispersion monitoring if near populated areas 5. Automatic shutdown controls for unsafe conditions	Lack of safety precautions can lead to greater risk of CO2 leakage

QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA)				
CarbonSAFE Rocky Mountains Phase I, CO2-Storage Subsurface, Surface, Technical and Programmatic Risk Areas				
Line #	**Index #**	**Risk Area/FEP**	**Description**	**Relevance**
454	**22.07.00.**	Production well submersible pump	While normally very reliable, the submersible pump in an EOR or ECBM production well can fail.	Failure of the submersible pump can result in operating delays and maintenance costs.
455	**22.08.00.**	Production well materials of construction	Production wells tend to be exposed to mixtures of CO_2, brine, hydrocarbons (oil and/or gas) and stripped gases such as H_2S. Production wells may also be exposed to hydrocarbon (asphaltene, paraffin or polyaromatic) deposition. Teflon coating has proven to help reduce hydrocarbon deposition. Scale buildup may also be a problem depending on brine chemistry.	The produced mixtures can be very corrosive. Hydrocarbon deposition or scale buildup may cause significant down time for cleaning out.
456	**23.00.00.**	**CO2 MONITORING RISKS**		
457	**23.01.00.**	Data acquisition activities at the well	Activities include logging, drill stem tests, coring, hydrophone installation, etc.	May include some activities and procedures that are less familiar. Some techniques could limit other MMV techniques.
458	**23.02.00.**	Data acquisition activities away from the well	Many activities and procedures will be effectively new and newly trained for. Some monitoring techniques could present risk or barriers to the application or success of other techniques.	Off-site monitoring activities may incur risk of physical accidents and may make the project publicly prominent.
459	**23.03.00.**	Data acquisition conflicts	Data acquisition may involve many techniques including logging, fluid sampling, coring, surface and downhole geophones, surface seismic, surface air measurements, groundwater sampling, and others.	Use of some monitoring techniques can preclude or limit the applicability of other techniques.
460	**23.04.00.**	Seismic surveys	Vertical resolution of seismic imaging is inherently limited such that features less than 10 m thick can rarely be discerned. (CCP 2009) Subsurface CO_2 is not seismically resolvable. Limited or absence of plume images via seismic. Seismic readings may be compromised by vibration from nearby heavy industrial facilities. 1. 2-D seismic survey 2. 3-D seismic survey 3. 4-D seismic survey 4. Vertical seismic profile (VSP)	Seismic techniques unable to pick up subsurface features or track CO_2 plume.
461	**23.05.00.**	Gravity surveys	As a notional rule of thumb, CO_2 filled reservoirs with less than 10% porosity, thicknesses of less than 10 m and depths greater than 2,500 m will be very difficult to resolve even with the best gravity data and mathematical inversion techniques. (CCP 2009) Current available standard gravimeters are capable of making repeat measurements valid to about 5 micro-gals. Fixed seal-floor gravimeters are essentially capable of the same. (CCP 2009) Corrections for motion are required for gravity data acquired from moving vessels. A change of only 1 cm of elevation will yield a difference of 3 micro-gals. Studies of oil fields have found that fixed permanent surface gravity monuments (i.e. stations) are essential to maximize repeatability (CCP	Gravity surveys unable to detect CO_2 movement

QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA)				
CarbonSAFE Rocky Mountains Phase I, CO2-Storage Subsurface, Surface, Technical and Programmatic Risk Areas				
Line #	**Index #**	**Risk Area/FEP**	**Description**	**Relevance**
462	**23.06.00.**	InSAR surveys	InSAR is the current state-of-the-art satellite platform radar based technique to measure vertical ground elevations and relative elevation changes with time. (CCP 2009) Validation studies have shown that uplifts of 1-3 mm can be reliably and repeatedly measured when sites make use of special corner reflectors for calibration purposes. (CCP 2009)	InSAR may be unable to accurately measure vertical ground elevations and relative elevation changes over time due to high seasonal vegetation growth.
463	**23.07.00.**	Well monitoring	Well monitoring for CO2 storage seeks confident validation that: - Cement integrity and bond is maintained - Pressure isolation barriers are maintained and functioning - Corrosion is being controlled - The CO2 injection profile is being maintained - Barriers after plug and abandonment provide confidence. (CCP 2009)	Unexpected well failure due to lack of well monitoring.
464	**23.07.00.**	General monitoring risks	1. Weather conditions prevent using a monitoring method or retrieving data at a critical point in time 2. Injection site terrain too rugged for surface monitoring 3. Monitoring equipment not properly calibrated 4. Inappropriate monitoring suggests a false alarm for issues that do not exist (CCP 2009) 5. Inappropriate monitoring suggests a false sense of security (CCP 2009) 6. Difficulty of geophysical techniques monitoring below salt caprocks (CCP 2009) 7. Ineffective monitoring 8. Insufficient monitoring 9. Lack or loss of monitoring records 10. Accidental damage or breakdown of custom-made equipment, sensors or tools - repair/replacement delays and irretrievable data loss. 11. Conflicting results from different monitoring techniques. 12. Difficulty of monitoring stacked injection plumes	Ineffective or lack of monitoring can result in missed data. This leads to inadequate engineering control, raising costs and leakage risks; yields insufficient documentation to establish CO2 storage credits, etc.
465	**23.08.00.**	Pre-closure monitoring of storage (02.01.07.00.)	Processes related to any monitoring undertaken during the operational and closure phase. The extent and requirement for such monitoring activities may be determined by issues such as storage concept, geological setting, regulations, or public pressure. A number of monitoring techniques exist including seismic data, electrical resistance, soil gas and isotopic characteristics.	Monitoring during the operational phase contributes towards the amount and quality of information initially available after closure concerning the behavior and distribution of sequestered CO2.
466	**23.09.00.**	Post-closure monitoring of storage	FEPs related to any monitoring undertaken during the post-closure phase. This includes monitoring of parameters related to the long-term safety and performance. The extent and requirement for such monitoring activities may be determined by issues such as storage concept, geological setting, regulations, or public pressure. A number of monitoring techniques exist including seismic data, electrical resistance, soil gas and isotopic characteristics.	Post-closure monitoring will provide information regarding the performance of the sequestration project and may trigger post-closure remedial actions, if necessary.

Rocky Mountain CarbonSAFE Phase I

Appendix K

Legal, Regulatory, and Liability Assessment
CarbonSAFE Rocky Mountain Phase I

Legal, Regulatory, and Liability Assessment
CarbonSAFE Rocky Mountain Phase I

Lincoln Davies,[I] John Ruple,[II] Candace Cady,[III] Thomas Kessinger,[IV] and Lisa Sledge[IV]

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I. INTRODUCTION

Prior analyses have identified a wide variety of legal, regulatory, and other hurdles that Carbon Capture and Sequestration (CCS) projects may face. Many of these studies suggest that what limits CCS deployment is not always legal or regulatory in nature. Several early studies, for instance, suggested that the lack of commercial-scale CCS demonstration projects act as a key constraint on societal appetite for CCS generators.[1] However, subsequent research revealed that technology demonstration tends not to be the key impediment to commercial-scale CCS development. Rather, a 2013 survey of more than 200 experts[2] in the United States revealed that there are four key barriers to CCS commercialization:

(1) cost and cost recovery;
(2) the lack of price signal or financial incentive for using CCS;
(3) liability risks; and
(4) an overall lack of comprehensive CCS regulation.[3]

The 2013 study provided important context to the legal, regulatory, and social barriers that, at a broad scale, CCS projects face. Specifically, it showed that, above all else, the cost of CCS—including the energy penalty that CCS imposes on electricity generation as well as public resistance to higher energy prices—is the greatest impediment facing commercial-scale CCS deployment. Following cost, the experts surveyed in the 2013 study suggested that the lack of any clear price signal or other financial incentive for CCS use, such as a carbon tax or greenhouse gas cap-and-trade system, is the second most significant barrier to CCS commercialization. Following cost and the lack

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[1] *See generally, e.g.*, CARNEGIE-MELLON UNIV., DEPARTMENT OF ENGINEERING AND PUBLIC POLICY, CARBON CAPTURE AND SEQUESTRATION: FRAMING THE ISSUES FOR REGULATION, AN INTERIM REPORT FROM THE CCSREG PROJECT (2009); PETER FOLGER, CONG. RESEARCH SERV., CARBON CAPTURE AND SEQUESTRATION (CCS) (2009); GOV'T ACCOUNTABILITY OFFICE, REPORT TO THE CHAIRMAN OF THE SELECT COMMITTEE ON ENERGY INDEPENDENCE AND GLOBAL WARMING, HOUSE OF REPRESENTATIVES: FEDERAL ACTIONS WILL GREATLY AFFECT THE VIABILITY OF CARBON CAPTURE AND STORAGE AS A KEY MITIGATION OPTION (2008); INT'L ENERGY AGENCY, CARBON CAPTURE AND STORAGE: PROGRESS AND NEXT STEPS (2010); LARRY PARKER ET AL., CONG. RESEARCH SERV. CAPTURING CO_2 FROM COAL-FIRED POWER PLANTS: CHALLENGES FOR A COMPREHENSIVE STRATEGY (2009); WORLD RESOURCES INST., OPPORTUNITIES AND CHALLENGES FOR CCS (2007).

[2] These experts consisted of with experience as CO_2 emitters, CCS operators, consultants, regulators, researchers, and nonprofit organizations relevant to CCS.

[3] Lincoln L. Davies et al., *Understanding Barriers to Commercial-Scale Carbon Capture and Sequestration in the United States: An Empirical Assessment*, 59 ENERGY POL'Y 745, 749 (2013).

of a price signal, those respondents found the most significant barrier to CCS to be liability risks associated with CO_2 storage, followed by the lack of an overall CCS regulatory framework.[4]

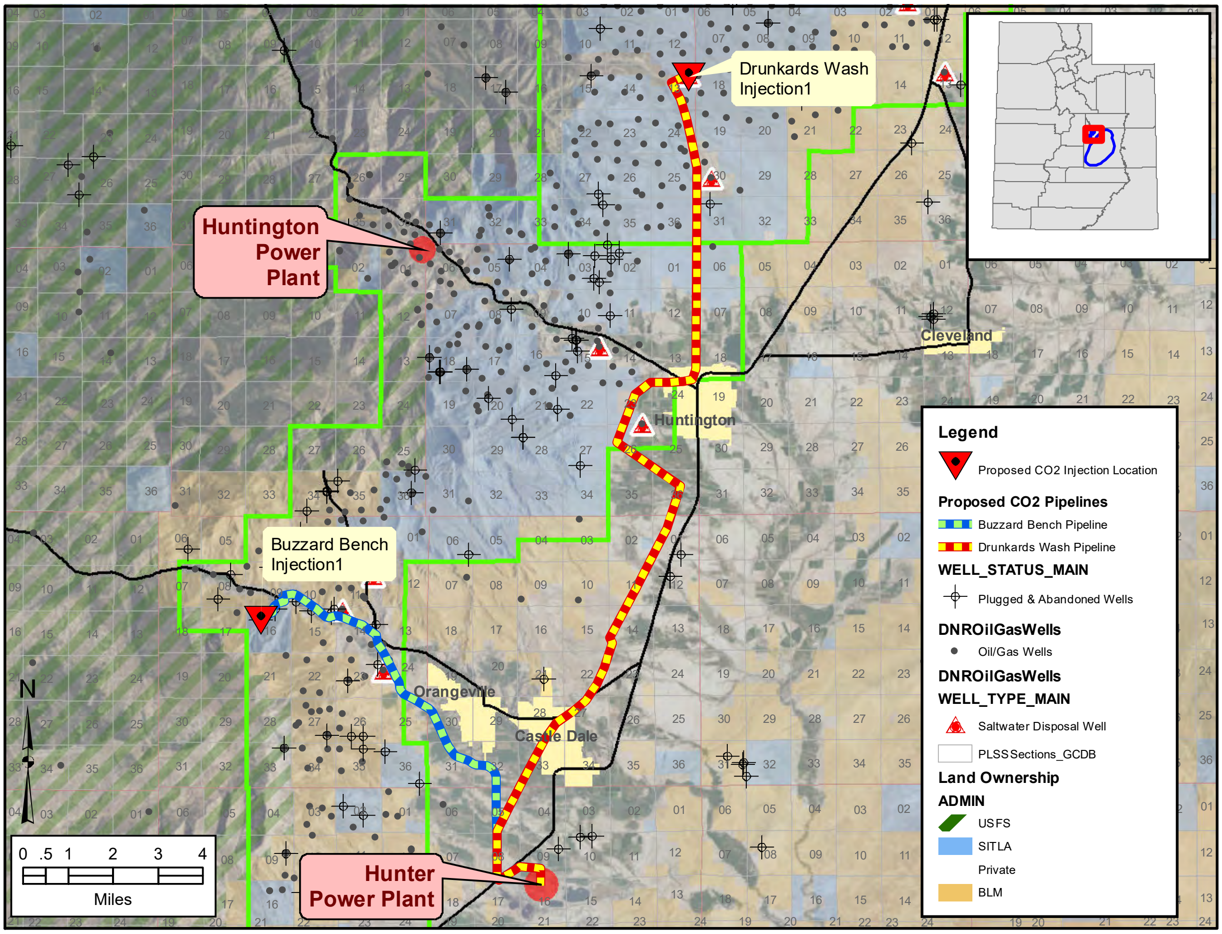

Figure 1. CarbonSAFE Rocky Mountain Location Map

This report seeks to identify the legal and regulatory structure that will govern development of any commercial-scale CCS project, including potential gaps in the legal and regulatory scheme. It does so in the context of the potential CarbonSAFE Rocky Mountain project, which would capture CO_2 from Rocky Mountain Power's Hunter or Huntington power plants and geologically store the CO_2 in the geographically proximate Navajo sandstone saline formation. A rough schematic of the proposed project, as it is currently envisioned and on which this analysis is based, is shown below as Figure 1. The analysis herein is by necessity conceptual. It identifies and details overarching categories of applicable law and regulation, because more concrete application of that law to the

[4] Subsequent research has broadly confirmed the 2013 study's results. In a 2017 study, researchers evaluated expert views of CCS risk perception in three European countries. Perceived barriers across countries and experts included the high cost of implementing technologies, the slow development of policy and regulation, the absence of storage sites, and general liability. *See generally* Farid Karimi & Nadejda Komendantova, *Understanding Experts' Views and Risk Perceptions on Carbon Capture and Storage in Three European Countries*, 82 GEOJOURNAL 185 (2017).

proposed project cannot be achieved until the specific contours and location of the project are delineated following more in-depth geologic analysis, at a later date.

CCS occurs in three industrial segments: first, CO_2 *capture*; second, CO_2 *transport*; and, finally, CO_2 *storage*. Consistent with the scope of this Phase I study, this portion of the report addresses legal, liability, and regulatory barriers for transport and storage.

This section of the report is organized as follows. It first addresses use of the land necessary for both CO_2 transport and storage, including surface land use, subsurface use, and Bureau of Land Management (BLM) regulation.[5] It then discusses potential liability associated with geologic storage of CO_2 as part of CCS technology, including permitting under the Safe Drinking Water Act (SDWA). Because the proposed CarbonSAFE Rocky Mountain project is proximate to federal land and will likely require federal permits, we then discuss application of the National Environmental Policy Act (NEPA). Finally, other generally applicable legal and regulatory requirements are discussed, along with key lessons learned from parallel CCS projects.

II. LAND USE

Both surface and sub-surface access for CCS potentially implicate three general categories of land ownership near the CarbonSAFE Rocky Mountain project: privately owned lands, state owned lands, and federally owned lands. Surface uses include pipeline access connecting the CO_2 source to the injection site, as well as the injection site itself and associated infrastructure. Sub-surface use includes permanent geologic CO_2 sequestration within the receiving geologic formation, which is defined spatially by the extent of the CO_2 plume. We address surface and sub-surface rights in turn, for each type of ownership category, followed by general discussions of pore space ownership for the CarbonSAFE Rocky Mountain project as well as how to acquire access to such rights, including by negotiation (leasing, easement, or purchase) or exercise of governmental authority (eminent domain).

A. Surface Land Use

As noted, three different types of landowners possess surface property rights near the proposed CarbonSAFE Rocky Mountain project: private, state, and federal. Acquiring rights to use the surface of land owned or managed by these entities will necessarily involve different processes.

1. Private Ownership

Private landowners are generally free to alienate all or some subset of the rights that they hold. In the law, property often is referred to as a "bundle of sticks." This means that a landowner may sell, lease, or otherwise grant rights to the use of the surface estate while still retaining overall ownership of the property. With respect to the CarbonSAFE Rocky Mountain project, then, if access is needed to privately owned surface lands, negotiated transactions would likely need to be used, particularly since eminent domain authority has not been developed fully in the CCS context, and the cost of such proceedings would likely be prohibitive both financially and in terms of potential project delays.

2. State Ownership

The Utah School and Institutional Trust Lands Administration (SITLA) manages most, if not all, of Utah's surface and sub-surface estate within the vicinity of the proposed CarbonSAFE Rocky Mountain project area. State law provides mechanisms for the sale of state lands, but

[5] CarbonSAFE Rocky Mountain is not anticipating use of the surface of National Forest System land.

obtaining a lease or easement would likely be a more efficient solution. With respect to pipelines transmitting CO_2 from the power plant to the injection site, rights-of-way may already be in place, depending on what transport path is selected. An existing easement could presumably be amended to accommodate additional pipeline infrastructure. Alternatively, a new easement could also be acquired.

3. Federal Ownership

The process for acquisition of rights to utilize federally managed surface resources is relatively well-defined. Indeed, over the last several decades, the Department of the Interior promulgated an extensive series of regulations that makes securing a surface lease or utility right-of-way on the type of federal lands proximate to the proposed CarbonSAFE Rocky Mountain project comparatively routine.

All federal lands (both surface and sub-surface) within the project area are believed to be under BLM administration. The Federal Land Policy and Management Act[6] (FLPMA) requires the BLM to "prepare and maintain on a continuing basis an inventory of all public lands and their resource[s]."[7] Based on this inventory, the BLM must "develop, maintain, and, when appropriate, revise land use plans which provide by tracts . . . for the use of the public lands."[8] These plans, commonly referred to as Resource Management Plans (RMPs), establish the management direction for a defined region of public land, although in practice such regions can be quite large, covering millions of acres. Critical RMP decisions include, among other things, which lands will be available for mineral development, which lands will be managed to emphasize resource protection, and what management stipulations are required to balance BLM's multiple use and sustained yield mandates across the federal landscape.[9]

The Price RMP applies to the CarbonSAFE Rocky Mountain project area and was most recently revised in 2008. It contains management stipulations applicable to lands proximate to both the primary and secondary injection sites of the CarbonSAFE Rocky Mountain project, likely pipeline corridors and the injection site(s). The Price RMP contains mapped management stipulations for approximately eighty different resources. As RMP consistency is a central focus of any BLM lease or right-of-way approval, we reviewed[10] the requirements contained in the Price RMP applicable to both the primary and secondary project sites.[11]

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[6] 43 U.S.C. §§ 1701–1787 (2012).

[7] *Id.* § 1711(a).

[8] *Id.* § 1712(a).

[9] *Id.* § 1701(a)(7).

[10] To conduct the review, we mapped the approximate location of the Hunter and Huntington power plants, the primary and secondary injection sites, and the approximate route for a pipeline connecting the power plants with the associated injection site. We then compared those maps with resource maps contained in the Price RMP and identified the resources most likely to constrain project development. Only those resource that were identified as likely to impact project development are addressed here.

[11] As noted, our analysis is by necessity conceptual in nature, which is particularly pertinent with respect to BLM permitting. As the location and contours of the CarbonSAFE Rocky Mountain project are more clearly defined via further geologic study, evaluation of the applicable RMP will need to be updated based on that more detailed information, once that information becomes available and is needed for use, such as in a Phase II study of the proposal. CCS operators should also bear in mind that not all management constraints can be mapped at the scale or resolution considered in an RMP. Project proponents should meet with BLM officials to identify any additional constraints that may exist prior to project implementation and development.

4. Hunter Power Plant (Primary CO_2 Source)

The Hunter Power Plant is located on privately owned lands south of the town of Castle Dale. CO_2 injection and geologic sequestration would likely occur west of Castle Dale, at the Buzzards Bench site. Injection is likely to occur on state trust lands that are surrounded by BLM-managed public lands. CO_2 would be transported via pipeline as shown in Figure 1. Further investigation will be needed to confirm that this right-of-way could serve the project. Alternatively, CO_2 could be piped to the Drunkards Wash oil field approximately eighteen miles to the north, also as shown in Figure 1. Lands proximate to the Drunkards Wash injection site are largely managed by SITLA, with a parcel of BLM-managed lands existing immediately east of the injection site. The Drunkards Wash site is discussed in more detail below, in conjunction with the Huntington Power Plant.

The RMP includes oil and gas surface use stipulations that are uniquely important to the project, as these stipulations apply much more broadly than their name might suggest. The RMP explains:

> The Approved RMP specifies restrictions for permitted activities to resolve concerns regarding the impacts of these uses. These conditions apply not only to oil and gas leasing, but also apply, where appropriate, to all other surface disturbing activities associated with land-use authorizations, permits, and leases, including other mineral resources.[12]

BLM-managed lands in the Buzzards Bench area are generally open to mineral development under "standard lease terms and conditions" or under "minor constraints."[13] Standard lease terms and conditions are the least restrictive category of stipulations and allow the BLM to require the operator to move proposed facilities by up to 200 meters and prohibit new surface disturbing operations for up to sixty days per year.[14] "Minor constraints" may include timing limitations, controlled surface use stipulations, or lease notices that could result in a cumulative timing limitation of three to six months.[15]

The BLM applies a Visual Resource Management classification system to describe limits on visual impacts allowed across the landscape. Lands near Buzzards Bench are subject to Class 3 and Class 4 stipulations, which are generally facilitative of more intensive forms of development. Class 4 areas are managed to "provide for management activities which require major modification of the existing character of the landscape. The level of change to the characteristic landscape can be high."[16] The BLM manages Class 3 areas to "partially retain the existing character of the landscape. The level of change to the characteristic landscape should be moderate."[17]

With respect to ecological considerations, few riparian areas are identified in the RMP as proximate to the injection site, with the exception of two riparian areas north of Orangeville and one riparian area west of Castle Dale. Impacts to riparian areas, wetlands, and waters of the United States

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[12] BUREAU OF LAND MGMT., DEP'T OF THE INTERIOR, PRICE FIELD OFFICE RECORD OF DECISION AND APPROVED RESOURCE MANAGEMENT PLAN 40 (2008) (hereinafter the Price RMP).

[13] *Id.* at Maps R-24 and R-26.

[14] 43 C.F.R. § 3101.1-2 (2017).

[15] Price RMP, *supra* note **Error! Bookmark not defined.**, at Map R-26.

[16] *Id.* at Tbl. 3-12.

[17] *Id.* at Map R-5.

are regulated under the Clean Water Act and may require additional permitting. Care should be taken to identify all wetland areas, surface waters, and intermittent drainages; to avoid such areas whenever possible; and to obtain appropriate permits for unavoidable impacts. Given the resolution of mapping contained in the RMP, CCS operators should not assume that RMP mapping of aquatic resources is complete or accurate.

Lands west of the Buzzards Bench injection site are characterized by a mix of sagebrush and Pinyon-Juniper cover. These lands provide mule deer habitat that is mapped as part of the Big Game Crucial Habitats layer contained in the Price RMP.[18] The Price RMP does not identify either winter habitat or crucial value nesting or brood rearing habitat for the greater sage grouse in the general area.[19] No crucial year-long white-tailed prairie dog habitat has been identified in the area.[20] Similarly, the Price RMP does not identify any designated critical habitat for threatened or endangered species, or state wildlife management areas in the immediate vicinity of Castle Dale.[21] Areas of Critical Environmental Concern, Wilderness Study Areas, and Non-WSA Lands with Wilderness Characteristics have not been identified in the Orangeville area.[22]

5. Huntington Power Plant (Secondary CO_2 Source)

The Huntington Power Plant, considered the secondary source for this proposed project, is located north of the Hunter Power Plant and northwest of the town of Huntington. The Huntington Power Plant is located on private land and ringed by private and SITLA-managed lands. The approximate CO_2 injection site is roughly thirteen miles northeast of the power plant, in the Drunkards Wash oil field. Lands proximate to the injection site are largely managed by SITLA, with a BLM-managed lands existing largely to the east of the injection site.

The Price RMP identifies a utility corridor extending to the southeast from the approximate location of the Huntington Power Plant, to points south and southwest of the town of Huntington. From there, rights-of-way extend to the northeast along Utah State Highway 10, and due north.[23] Either route could provide access to the Drunkards Wash Field, though transport distances would increase significantly over those associated with the Hunter Power Plant.

There is generally less BLM-managed land proximate to the Huntington Power Plant compared to the Hunter Power Plant. What BLM-managed lands do exist near the Drunkards Wash injection site are generally managed under "minor" surface constraints that could limit surface-disturbing activities for three to six months of the year.[24] Visual Resource Management stipulations for BLM-managed lands due east of the likely injection site are unlikely to pose a constraint, as they are managed to "provide for management activities which require major modification of the existing character of the landscape. The level of change to the characteristic landscape can be high."[25] The Price RMP identifies riparian habitat near the likely injection site and, as with the Hunter Power Plant site, care should be taken to identify and avoid wetlands, surface waters, and intermittent drainages. Where these features cannot be avoided, additional permitting will be required.

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[18] *Id.* at Map R-8.
[19] *Id.* at Map R-6.
[20] *Id.* at Map R-9.
[21] *Id.* at Map R-7.
[22] *Id.* at Maps R-11, R-28, and R-29.
[23] *Id.* at Map R-21.
[24] *Id.* at Maps R-25 and R-26.
[25] *Id.* at Map R-5.

The Huntington-Drunkards Wash area is classified as crucial habitat for both Rocky Mountain Elk and Mule Deer. This habitat extends from the Huntington Power Plant to the likely injection site.[26] CCS operators should consider ways to avoid, minimize, and mitigate unavoidable wildlife habitat impacts as they develop project plans. Crucial year-long habitat for white-tailed prairie dogs has been identified to the north of the likely CO_2 injection site.[27] The Price RMP does not identify greater sage grouse habitat near the likely injection site,[28] nor does it identify any designated critical habitat for threatened or endangered species or state wildlife management areas in the immediate vicinity of Orangeville.[29] As noted above, areas of Critical Environmental Concern, Wilderness Study Areas, and Non-WSA Lands with Wilderness Characteristics have not been identified in the area.[30]

6. Greater Sage Grouse

Greater sage grouse pose an additional federal land use issue that is relevant to both the primary site and the secondary site. The greater sage grouse is a chicken-sized bird that lives in sagebrush steppe environments across the western United States. Greater sage grouse populations have declined precipitously, prompting a call to list the greater sage grouse under the Endangered Species Act (ESA). Faced with a court-ordered deadline to act on an ESA listing petition, and fearing that a listing decision could severely impact extractive industries across the West, a host of state and federal agencies developed a series of land use restrictions intended to protect the bird and preclude the need for ESA listing. These efforts were successful, culminating in a 2015 U.S. Fish and Wildlife Service (FWS) decision that ESA listing was not needed because other state and federal government actions adequately protect the bird.[31] Relevant to this project, the BLM and the U.S. Forest Service issued programmatic amendments to all land and resource management plans within the state of Utah. The state of Utah also issued its own greater sage grouse management plan.

Greater sage grouse are known to inhabit lands in the vicinity of both the primary and secondary sites. Maps of greater sage grouse conservations areas that are contained in the programmatic amendments to BLM and Forest Service planning documents, however, lack the resolution needed to determine the extent of the constraint that the greater sage grouse could impose on the proposed CarbonSAFE Rocky Mountain project. While it is likely that greater sage grouse habitat could be avoided (if it exists within the project area), care must be taken to further evaluate this issue as more information becomes available relevant to pipeline and well locations. State protections for the greater sage grouse should also be considered, as they would apply on state and private land, including those in the vicinity of the secondary injection site.

Federal greater sage grouse management efforts are currently subject to litigation and are also undergoing administrative review that may result in less onerous protections. These administrative efforts will take several years and are likely to be mired by litigation, if they proceed at all. Proponents acting in areas with known greater sage grouse habitat are therefore advised to avoid habitat impacts to the extent possible.

Congress has temporarily prohibited the Fish and Wildlife Service from expending funds on the promulgation of a rule that lists the greater sage grouse under the ESA. While this prohibition is likely to remain in effect during the current Congress, there is no guarantee that these prohibitions

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[26] *Id.* at Map R-8.
[27] *Id.* at Map R-9.
[28] *Id.* at Map R-6.
[29] *Id.* at Map R-7.
[30] *Id.* at Maps R-11, R-28, and R-29.
[31] 80 Fed. Reg. 59858 (Oct. 2, 2015).

will persist in perpetuity. The lowest risk course of action, therefore, is to avoid greater sage grouse habitat.

7. The Emery County Lands Bill

On May 21, 2018, Representative John Curtis of Utah introduced House Resolution 5727, which would the establish the 336,467-acre San Rafael Swell Western Heritage and Historic Mining National Conservation Area, designate 529,146 acres of wilderness within Emery County, create the Jurassic National Monument, and provide for certain conveyances of federal land to the state of Utah. The Hunter drill site is approximately twenty-miles west of the proposed National Conservation Area (NCA). The Drunkards Wash drill site is approximately twelve miles to the east of the proposed Candyland Mountain Wilderness Area, and approximately seventeen miles west of the proposed Jurassic National Monument.

The Emery County Lands Bill has not advanced to a vote and the likelihood of passage is uncertain. If the bill passes, there is significant distance between all CarbonSAFE Rocky Mountain facilities and the protective designations proposed under the bill. The CarbonSAFE team should, nonetheless, pay close attention to this pending legislation. Federal land management decisions within Utah attract significant attention and often prove to be very contentious. The San Rafael Swell has long been considered a potential site for a national monument designation, and the conservation community will likely oppose any development that they perceive as threatening resources within the Swell, including threats posed by visual or auditory impacts.

While direct impacts to the San Rafael Swell appear unlikely to result from implementation of the CarbonSAFE Rocky Mountain project, perceptions and fears or adverse impacts may necessitate careful articulation of how the project was designed to avoid impacting resources within or near the Swell. The CarbonSAFE team should also anticipate that intense public scrutiny will be directed towards this project.

B. Subsurface Land Use

In addition to use of surface land for CO_2 transport and injection, CCS projects also implicate use of the subsurface. These issues are somewhat more complicated than the surface land issues. Typically, the question boils down to ownership of the subsurface lands. However, this ownership question can be complicated for a variety of reasons. First, a situation may arise where there is a different owner of the surface land than the subsurface land—a situation known as the "split estate" question. Second, the subsurface estate itself may be subdivided further into component estates based on the existence of specific minerals or other geological characteristics. Third, the subsurface owner may have leased some or all of the subsurface estate, potentially creating overlapping mineral interests. Ownership of the subsurface estate often is referred to as ownership of the "pore space": the "spaces within a rock body that are unoccupied by solid material."[32] This is the portion of the subsurface that geologically stored CO_2 will occupy.

Historically, property rights have been referred to as "sticks" in a "bundle" of various rights.[33] Different rights can be separated from each other in a legal sense; each such right is referred

[32] *Definition: Pore Space*, www.idahogeology.org/services/hydrogeology/portneufgroundwaterguardian/my_aquifer/vocab/vocab_text/pore_space.html (last visited Jul 29, 2017).

[33] *See* M. GRANGER MORGAN & SEAN T. MCCOY, CARBON CAPTURE AND SEQUESTRATION 95 (2012).

to as a "stick" in the overall "bundle" of property rights, and it is appropriate to look at pore space ownership as its own "stick" in the property bundle.[34]

Generally, the owner of a fee simple estate (*i.e.*, full ownership of the surface and sub-surface land) will own the pore space beneath their land.[35] This is an application of the *ad coelum* doctrine, which historically stood for the proposition that an owner of a surface estate owns from the depths of the earth to the extent of the universe. As society has evolved, courts have recognized limits on the *ad coelom* doctrine. For instance, courts typically now place a ceiling on the ownership of a surface owner's airspace. However, judicial decisions have not attempted to place a floor on the ownership of the subsurface estate underlying a fee-simple property owner's land. Therefore, generally, the owner of a fee-simple estate will own the pore space that lies underneath a given tract of land.

This quickly becomes murkier in split estate or competing use issues, situations very familiar to the oil and gas arena. Split estates are created "when the surface estate and all or part of the mineral estate in a particular parcel are not owned by the same party."[36] Internationally, the majority of countries reserve ownership of the mineral and other subsurface estates to the sovereign government. In the United States, however, there is widespread private ownership of subsurface estates.[37] The rise in usage of pore space outside of the context of CCS necessitated resolution first in the courts and later, in a minority of states, by legislation. Typically, two distinct rules guide the analysis for resolving split estate questions: the American Rule and the English Rule. Understanding these rules is important because ownership of pore space is not a settled issue, particularly with respect to ownership of pore space for CCS.[38]

1. The American Rule

The American Rule cleaves the mineral estate from the pore space,[39] regardless of whether they are physically bound together, and vests ownership of the pore space with the surface estate owner.[40] This rule developed through applying common maxims used to determine the ownership of the subsurface generally.[41] These maxims include the *ad coelum* doctrine, the narrow drafting of conveyances and narrow interpretation of those conveyances by courts,[42] and a presumption of a

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[34] *See* Trae Gray, *A 2015 Analysis and Update on U.S. Pore Space Law—The Necessity of Proceeding Cautiously With Respect to the "Stick" Known as Pore Space*, 1 OIL & GAS, NAT. RESOURCES & ENERGY J. 277, 279 (2015).

[35] *See* MORGAN & MCCOY, *supra* note 33, at 95

[36] Kendor P. Jones et al., *Split Estates and Surface Access Issues*, *in* LANDMAN'S LEGAL HANDBOOK, ch. 9 (Rocky Mt. Min. L. Fdn., 5th ed. (2013).

[37] *Id.*

[38] This report draws heavily from MORGAN & MCCOY, *supra* note 33; Alexandra B. Klass & Elizabeth J. Wilson, *Climate Change, Carbon Sequestration, and Property Rights*, 2010 U. ILL. L. REV. 363, 381 (2010); STEFANIE L. BURT, WHO OWNS THE RIGHT TO STORE GAS: A SURVEY OF PORE SPACE OWNERSHIP IN U.S. JURISDICTIONS (2012); and Gray, *supra* note 34.

[39] Ellis v. Arkansas Louisiana Gas Co., 450 F. Supp. 412, 421 (1978), *aff'd*, 609 F.2d 436 (10th Cir. 1979).

[40] This principle is likened to excavating a basement. If party A contracts with party B to remove the dirt underneath a tract of land owned by party A, party B does not obtain title to the newly created space. Accordingly, the owner of a mineral estate cannot lay claim to the pore space they create after extraction of gas or other mineral deposits, or even when the space is naturally occurring rather than created through extraction. *See, e.g.*, *Burlington Res. Oil & Gas Co., LP v. Lang & Sons Inc.*, 259 P.3d 766, 771 (Mont. 2011).

[41] *See* Owen L. Anderson, *Geologic CO_2 Sequestration: Who Owns the Pore Space?*, 9 WYO. L. REV. 97 at 99–100 (2009); *see also* MORGAN & MCCOY, *supra* note 33, at 95–96.

[42] *See Ellis*, 450 F. Supp. at 420.

reservation of rights by surface holders when they are not expressly conveyed or necessary to reduce and capture a given mineral resource.[43]

Because no court has dealt with the issue of pore space solely in the CCS context, application of the American Rule to CCS must be guided by other subsurface storage uses, such as natural gas storage. The case of *Ellis v. Arkansas Louisiana Gas Co.* provides an example[44] There, the court was asked to determine from whom a natural gas storage injector needed to obtain permission to store its natural gas, where a split estate existed. Plaintiffs owned seventy-eight acres of a surface estate in Oklahoma.[45] The mineral estate had been severed through a series of deeds. The gas reservoir had been depleted, so the mineral estate holder had been using the reservoir to store gas. The court held that the surface estate owned the subsurface pore space created by the depleted gas reservoir. This was because the legal instruments that severed the mineral estate conveyed the right to explore and develop the minerals in the estate but said nothing about who owned the depleted reservoir.[46] As a result, under the American rule, ownership of that space remained with the surface estate owner—and that was from whom the gas storage operation needed to acquire storage rights.

a. Mineral Estate Dominance

Courts have repeatedly held that the subsurface estate implicitly comes with certain additional rights. This typically is referred to as the "dominance" of the mineral estate over the subsurface estate.[47] In the oil and gas context, for instance, courts have long held that the mineral estate is dominant over the surface estate because the development of a mineral estate necessarily requires some surface access.[48] Thus, generally, when a mineral estate is severed from the surface estate, there exists either an express or implicit reservation that the mineral estate holder is allowed to use portions of the surface estate needed to facilitate development of the mineral estate.[49]

b. The Accommodation Doctrine

In response to the idea of mineral estate dominance, courts also developed the accommodation doctrine. This doctrine attempts to balance the interests of the surface and subsurface estates. First announced in *Getty Oil Co. v. Jones*,[50] the accommodation doctrine imposes a requirement on the mineral estate that all mineral-estate-surface-uses must be "reasonably necessary" and accommodate the existing uses of the surface estate. The Utah Supreme Court summarized this doctrine in *Flying Diamond Corp. v. Rust*:[51]

> [M]ineral rights [are] dominant over the rights of the owner of the [surface estate] to the extent reasonably necessary to extract the minerals therefrom. This dominance is limited in that the mineral owner may exercise that right only as reasonably necessary

[43] *See* MORGAN & MCCOY, *supra* note 33, at 95–96; *see also Ellis*, 450 F. Supp. at 421.
[44] *Ellis*, 450 F. Supp. 412 at 414.
[45] *See Ellis*, 609 F.2d at 439.
[46] *Ellis*, 450 F. Supp. at 421.
[47] *See* Smith v. Linmar Energy Corp., 790 P.2d 1222, 1224 (Utah Ct. App. 1990).
[48] *See generally* 4 SUMMERS OIL AND GAS § 40:4 (3d ed.).
[49] Smith v. Linmar Energy Corp., 790 P.2d at 1224 ("[A]s a general matter, ownership of mineral rights in land is dominant over the rights of the owner of the fee title to the extent reasonably necessary to extract minerals.").
[50] Getty Oil Co. v. Jones, 470 S.W.2d 618, 621 (Tex. 1971).
[51] 551 P.2d 509, 511 (Utah 1976)

> for that purpose and consistent with allowing the fee owner the greatest possible use of his property consistent therewith. . . . [W]herever there exist separate ownerships of interests in the same land, each should have the right to the use and enjoyment of his interest in the property to the highest degree possible not inconsistent with the rights of the other.[52]

In other words, while the mineral estate's dominance may impinge somewhat on how the surface estate is used, the accommodation doctrine limits that effect. It may mean that development of a subsurface pore space estate can be constrained by the surface estate rights as well.

For instance, in *Sunray Oil Co. v. Cortez Oil Co.*,[53] relied on by the *Ellis* court, the Oklahoma Supreme Court addressed ownership of pore space rights in a salt water disposal well. To resolve the dispute, the court relied on the accommodation doctrine. It reasoned that unless a mineral conveyance expressly grants more than the right to develop and explore for minerals such as oil and gas, the surface owner retains the right to use the pore space—and, thus, to grant its use to a third party.

2. The English Rule

In contrast to the American rule, the English rule vests ownership of the pore space with the mineral estate owner. That is, an entity that acquires the right to extract subsurface minerals—such as an oil and gas driller—also obtains the right to use the pore space by virtue of obtaining the mineral rights. The English rule states: "[T]he mineral interest owner has the exclusive right of possession of the whole space and, after all minerals have been extracted, the owner is entitled to the entire and exclusive use of that space for all purposes."[54]

Central Kentucky Natural Gas Co. v. Smallwood is an illustrative case. There, the court needed to determine whether the surface owner or the mineral estate was entitled to lease an exhausted reservoir to store natural gas.[55] The court found that the mineral estate held the right not only to explore and develop those minerals but also the right to exclude others from exploring and developing such minerals. In accord with these exclusive rights, the court ruled, the mineral estate held the right to lease storage rights to others.[56]

The Kentucky Supreme Court subsequently overruled *Central Kentucky Natural Gas Co.* on other grounds. In *Texas American Energy Corp. v. Citizens Fidelity Bank & Trust Co.*, the Kentucky court held that an entity that reinjects natural gas into an underground formation for storage does not abandon ownership of the injected gas.[57] The *Texas American Energy* opinion, however, did not address ownership of the power space. *Central Kentucky Natural Gas Co.*'s holding that pore space ownership is vested with the mineral estate owner therefore appears to remain intact. The case, moreover, illustrates the difference in approach between the American rule and the English rule. Where the American rule turns on the idea that conveyance of subsurface rights typically should be narrowly construed, the English Rule hinges on the idea that pore space itself is mineral in character and, therefore, part of the mineral estate.

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52 *Id.* (citations and footnotes omitted).

53 112 P.2d 792 (Okla. 1941)

54 Elizabeth Lokey Aldrich & Cassandra Koerner, *Analysis of Carbon Capture and Sequestration Pore Space Legislation: A Review of Existing and Possible Regimes*, 24 ELECTRICITY J. 22–33, 22-33 (2011).

55 *See* 252 S.W.2d 866 (1952).

56 *Id.*

57 736 S.W.2d 25, 27 (Ky. 1987).

The English rule stands in contrast to the American rule in another way. It is a minority position. Only a limited number of jurisdictions within the United States follow the English rule. In fact, in the context of natural gas storage, only three states appear to continue to apply the English rule: Alaska, Kentucky, and Texas.[58]

C. Pore Space Ownership for a Utah CCS Project

A majority of oil-producing states follow the American rule.[59] This is often via development of the common law. Many jurisdictions have yet to codify this principle, instead resolving pore space issues in court. A small number of states have enacted legislation that places pore space ownership in the surface estate. Utah, however, has not adopted legislation defining pore space ownership, and no case law from Utah directly addresses ownership in the CCS context.

While Utah law is not entirely clear which entity owns the pore space into which CO_2 would be injected,the surface estate owner or the mineral estate holder, the Utah Legislature has enacted legislation regarding natural gas storage which implies that pore space should be considered part of the surface estate. The Utah Legislature has directed the state Department of Natural Resources, to create pore space ownership and other rules for CCS.[60] Utah began to undertake an effort to adopt such rules in 2009 and 2010. However, after the EPA announced its final rule for Class VI Underground Injection Control wells under the Safe Drinking Water Act, Utah put its plans to adopt CCS rules on indefinite hold. Notwithstanding that hold, recommendations from the state's CCS Rules Working Group[61] suggest that Utah likely would have adopted the American rule with respect to CCS pore space ownership.[62]

Further, Utah Code § 78B-6-501(6)(d) grants the mineral estate owner the right to condemn "any subsurface stratum or formation" for natural gas storage. By granting the mineral estate owner the power of condemnation for pore space to store natural gas, the legislature necessarily concluded that the mineral estate owner did not already own the pore space—if they did, there would be no need for the power of condemnation. Since the strong implication from § 78B-6-501(6)(d) is that pore space does not belong to the mineral estate owner, it logically follows that, in accord with the American rule, pore space is owned by the surface estate owner in Utah.

In Utah, an argument could also be made that, as at least as applied to state lands, conveyance of pore rights must be express—a position again consistent with the American rule. Under SITLA's mineral reservation statutes, pore space must be reserved to the state when SITLA sells lands to private parties. Utah Code § 53C-1-102 imposes several "fiduciary duties" on SITLA, including a duty to "manage the lands . . . in the most prudent and profitable manner possible[.]"[63]

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58 *See* BURT, *supra* note 38, at 5. *See also City of Kenai v. Cook Inlet Nat. Gas Storage Alaska, LLC*, 373 P.3d 473, 480–81 (Alaska 2016) (holding that a reservation of a mineral right implied the reservation of the right to use pore space to store natural gas).

59 *See generally* BURT, *supra* note 38; *see also* Gray, *supra* note 34.

60 *See* UTAH CODE § 54-17-701.

61 *See* UTAH CODE § 54-17-701 (creating this CCS Rules Working Group); *see also* Utah Dep't of Envtl. Quality, Utah Dep't of Natural Resources, Recommended Rules for Carbon Capture and Geologic Sequestration (Nov. 15, 2010), https://pscdocs.utah.gov/misc/miscindx/documents/RecommendedRulesforCarbonCaptureandGeologicSequestration11-15-2010.pdf (hereinafter Utah Rec. Rules).

62 *See* Utah Rec. Rules, *supra* note 61. It appears that no further action is being taken regarding adoption of the rules.

63 UTAH CODE § 53C-1-102.

Further, sales of stand lands "[must] contain . . . a [coal and mineral] reservation."[64] Excepted from that reservation are "common varieties of sand, gravel, and cinders"—but not exempted are "deposits which are valuable because the[y] contain[] characteristics which give it distinct and special value."[65] Therefore, if pore space is of distinct and special value, it may be statutorily reserved to SITLA. While this provision applies only to land sales, SITLA may apply the same principle when issuing mineral leases.

As part of Phase II, the CarbonSAFE Rocky Mountain Team should review all existing mineral leases proximate to the injection site, whether those leases were issued by the BLM, SITLA, or a private entity, and determine whether any of these leases address pore space use. If leases fail to indicate pore space ownership, the weight of authority implies that the surface owner also owns the pore space, and that ownership must be addressed in turn as part of legal approval for CCS operations.

D. Obtaining Land Use Rights

Because accessing private, state, and federal lands—both at the surface and subsurface—may be necessary to execute the proposed CarbonSAFE Rocky Mountain project, it is necessary to understand the process for obtaining such rights. This subsection describes available processes. At the outset, however, it is worth noting that particularly with respect to subsurface property rights, obtaining pore space remains a rather novel legal question. The state of Utah and the BLM have never granted an interest in pore space solely for the purpose of injecting CO_2 for permanent geologic sequestration. Therefore, each of the avenues presented below should be considered as options only, and not necessarily the only way to obtain an interest in pore space, while also recognizing that the processes could be altered when relevant decisional bodies are faced with the new situation of CO_2 injection and storage.

1. Acquiring Private Land Use Rights

Generally, fee-simple landowners are free to alienate or dispose of their property, including a subset of their rights. There are several ways to go about this, but they break down into two broad categories: agreement via negotiation and acquisition via governmental authority (*i.e.*, eminent domain).

a. <u>Agreement</u>

Three primary mechanisms tend to be used to acquire property rights from a fee simple landowner: leases, easements, and outright conveyances. Each of these could be used for both surface and subsurface rights acquisition.

Leases have been used in the mineral context for some time and are particularly common in the oil and gas context. Adapting this established framework could facilitate a CCS project. A lease for surface access would allow for ingress and egress, and use of the land to, for instance, transport CO_2 or inject it. For subsurface rights, obtaining a right to occupy the pore space would require the drafting and execution of a pore space lease. When using a lease, the operator should be mindful of the permanence of the sequestered CO_2 and the potential for interference with other uses. Presumably, oil and gas leases could serve as a starting point for tailoring a CO_2 storage lease.

An easement may provide a more permanent and elegant solution than a lease. Easements are particularly common in the energy and utility infrastructure context, where they are typically

[64] *Id.* § 53C-2-401.
[65] *Id.*

referred to as rights-of-way (ROW). Easements are "created by express words of either a formal grant or of a reservation or exception in a conveyance of land."[66] Like a lease, an easement does not create an ownership interest in the subject property, but rather, only the mere right to use the property in a given manner. The advantage of an easement is that it could exist in perpetuity until abandoned. This could be beneficial at the surface and subsurface level, and for pore space rights, may help navigate around the issue of permanence.

Lastly, a CCS operator could obtain the right to use land from an outright conveyance through a deed or other similar instrument. Use of such a mechanism is rather uncommon in the surface land context where the land is of significant value, and particularly where the property in question is large or the acquisition of the property will split the larger tract. In the subsurface context, however, the advantage of this route would be that ownership of the pore space will remain with the CCS operator in perpetuity. Still, this could be a costlier approach than the lease or easement options.

b. <u>Eminent Domain</u>

Eminent domain allows the taking of private property for public use by the state, municipalities, private individuals, or corporations that are authorized to exercise functions of a public character. Eminent domain can be utilized to obtain surface rights, subsurface rights, or both. Eminent domain authority is not available against the federal government unless expressly authorized by an act of Congress.[67]

Utah's eminent domain statute does not expressly grant a CCS operator authority to condemn certain real property.[68] The touchstone of eminent domain authority is a taking for a public use. Utah's eminent domain statute lists several statutory public uses, including "any subsurface stratum or formation in any land for the underground storage of natural gas."[69] Uses identified in the statute are "not exclusive . . . and merely establish a general starting point."[70] Therefore, if a CCS operation could demonstrate that geologic sequestration is a public use, the operator could conceivably claim authority to condemn property.[71] It is also noteworthy that the CCS Rules Working Group recognized the lack of express eminent domain authority for CCS operators, and recommended expansion of several areas of the eminent domain statute.[72]

Second, Utah law also provides that "the right of eminent domain may be exercised on behalf of . . . any occupancy in common by the owners or possessors of different mines, quarries, coal mines, mineral deposits, mills, smelters, or other places for the reduction of ores, or *any place for*

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66 UTAH REAL PROPERTY LAW § 12.02 (Lexis).

67 Utah Power & Light Co., 243 U.S. 389, 405 (1914). While the Utah Legislature has enacted legislation authorizing the use of eminent domain against the federal government, *see* UTAH CODE § 78B-6-503.5, this statute is almost certainly unconstitutional. As the Utah Office of Legislative Research and General Counsel warned the Legislature before enactment, "[T]he state has no standing as sovereign to exercise eminent domain or assert any other state law that is contrary to federal law on land or property that the federal government holds under the Property Clause." H.R. 143, 2012 Gen. Sess. (Utah 2012) (fiscal note appended to the introduced version of the bill).

68 *See generally* UTAH CODE §§ 78B-6-501 *et seq.* (2017)

69 *Id.* § 78B-6-501(6)(d).

70 *Utah Dep't of Transp. v. Carlson*, 2014 UT 24, ¶ 20, 332 P.3d 900, 904; *Salt Lake City Corp. v. Evans Dev. Grp., LLC*, 2016 UT 15, ¶ 11, 369 P.3d 1263, 1266.

71 *See, e.g.*, *Watkins v. Somonds*, 354 P.2d 852 (Utah 1960); *Jacobsen v. Memmott*, 354 P.2d 569 (Utah 1960).

72 *See* Utah Rec. Rules, *supra* note 61, at att. 2.

the flow, *deposit* or conduct of tailings or *refuse matter*."[73] While tenuous, a CCS operator—or coal mine operator—could argue that CO_2 should be classified as refuse matter to coal production. The argument would be that what is being sought is a place to dispose a product that, for commercial purposes, has little value. Thus, by analogy, CO_2 arguably could be considered akin to waste or, in statutory terms, "refuse matter." In response, an owner of condemned property would argue that such a reading of the statute is not in character with its intended meaning and, further, that CO_2 storage is not in the public use.

Given the untested nature of these arguments, the much safer route for a CCS operator seeking to use eminent domain authority would be to obtain a legislative amendment of the existing law, in accord with the CCS Rules Working Group's recommendation.[74] That is, an attempt to exercise eminent domain authority without such a legislative enactment would carry a high risk of litigation.

Another downside of using eminent domain bears mention. Eminent domain proceedings tend to provoke litigation and delay. Further, even if successful, they require payment for the resources seized, and valuation can invite further litigation. Negotiated transactions therefore appear highly preferable for CCS purposes.

2. Acquiring State Land Use Rights

A portion of the land granted to Utah at statehood is held by the state in trust for the benefit of the public schools and institutions.[75] These lands are now managed under the authority of the State of Utah School and Institutional Trust Lands Administration (SITLA).[76] SITLA lands are ubiquitous in and around the location of the proposed CarbonSAFE Rocky Mountain project.

There are several ways in which a private entity could obtain ownership or an interest in SITLA-managed lands. These fall into three broad categories that track the negotiation-based options for obtaining access to private lands: easements, leases, and land sales.

Notably, of these three avenues, private parties typically obtain an interest in SITLA lands through a variety of leases, including agricultural, grazing, and mineral leases. Commercial and renewable energy leases are also common. Obtaining the right to pore space under current SITLA regulations, however, would be a matter of first impression and would necessarily involve conferring and negotiating directly with SITLA.

a. <u>Easement</u>

To obtain an easement, a CCS operator would need to apply to SITLA under the procedures delineated in Utah Admin. Code R850-40 *et. seq*. Much of the language in these provisions suggests that these easements are not permanent, but it appears that SITLA may extend the life of an easement into perpetuity.[77] The minimum cost to the CCS operator would be the cost of administering the easement. If a CCS operator obtains an easement, the operator can assign the easement, but only with approval from SITLA.[78] Easements are managed by the Surface Group at SITLA and are commonly used for electrical lines, pipelines, and roads.

While technically allowable under SITLA's authority, easements are not commonly used when developing a resource. Instead, an entity typically requests a lease or a permit. A CCS operator

[73] UTAH CODE § 78B-6-501(6)(f).
[74] *See* Utah Rec. Rules, *supra* note 61, at Att. 2.
[75] *See* UTAH CODE § 53C-1-102.
[76] *See id.* §§ 53C-1-101 *et seq.*
[77] UTAH ADMIN. CODE R850-40-800 (2016).
[78] *Id.* R850-40-1600.

is arguably developing the pore space estate, not merely using it passively, as is done for utility lines or roads. After the CO_2 is injected, no one could further use the pore space, meaning that it is depleted, whereas after a pipeline is no longer needed, the land it has been occupying can be used for other purposes since the pipeline can be removed. Therefore, a lease would be a more logical—and perhaps more likely—way to develop a CCS project on SITLA lands, particularly with respect to subsurface rights as opposed to CO_2 transport.

b. Lease

Utah Admin. Code R850-30-100 *et seq*. defines SITLA's authority to issue special use leases. Special use leases may be required for pipelines or other infrastructure needed for CCS operations. Industrial special use leases are issued for periods of up to fifty-one years,[79] but in extraordinary circumstances, the lease term can be extended to ninety-nine years.[80] A lease for CCS use of pore space would most likely be classified as a special use lease because it is not within the standard definition of a mineral lease.[81] To obtain a special use lease, the applicant must follow procedures listed in Utah Admin. Code R850-30-500. The applicant may be required to submit a bond for reclamation as well as lease payments.[82] The lease rate will be based on market value and income-producing capability.[83]

c. Land Sale

State law vests SITLA with authority to sell trust lands under its management. There are two avenues by which SITLA may sell trust lands: a public sale or a negotiated sale.[84] SITLA commonly reserves the mineral estate during land sales, and most sales involve developable lands rather than linear features. Whether SITLA would entertain a proposal to sell lands for either CCS or for a pipeline is unclear, but it appears less likely than a lease. This is because a land sale permanently divests the property from SITLA, whereas a lease extracts income from the property while preserving the corpus of the land for future income-generating activity. As a trustee for the state's lands, SITLA has a fiduciary obligation to maximize benefit to the state from the trust lands. This likely explains why SITLA tends to reserve mineral rights when it engages in land sales.

3. Acquiring Federal Land Use Rights

Several different entities manage federally owned lands within the United States. In Utah, most federally owned land is managed by the Bureau of Land Management (BLM) and the U.S. Forest Service, and the BLM is responsible for the management of the federal subsurface mineral estates.

Both the BLM and the Forest Service manage lands under the broad and flexible principles of multiple use. That is, the statutes governing these agencies require them to seek to accommodate a balance of uses on federal lands, with the general idea in mind that the lands will produce a "sustained yield."[85]

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[79] *Id.* R850-80-200(3)(e); R850-80-200(2).
[80] *Id.* R850-80-200(2).
[81] *Id.* R850-80-100.
[82] *Id.* R850-80-800.
[83] *Id.* R850-80-400(1).
[84] *See id.* R850-80-610–615.
[85] 43 U.S.C. §§ 1701(a)(7), 1712(c)(1); 16 U.S.C. § 529.

Two primary authorities govern which lands the BLM can dispose of or grant usage rights to: The Federal Land Planning and Management Act (FLPMA)[86] and the Mineral Leasing Act (MLA).[87] FLPMA would govern rights-of-way needed for the transport phase of a CCS operation on federal lands managed by the BLM. Likewise, a CCS operator that is not pursuing an enhanced oil recovery project would obtain the right to use pore space under FLPMA. If the project also involves oil and gas development, the rights would be obtained under the MLA. The National Forest Management Act governs surface uses of lands managed by the Forest Service while the BLM manages minerals beneath Forest Service managed land surface pursuant to the MLA.

As in the state context, acquisition of rights of way for pipeline or other utility or transport uses is quite common on federal lands. However, use of federal lands for CO_2 storage would be a rather novel proposition. To our knowledge, no entity operates a CCS project on BLM land for the sole purpose of CO_2 sequestration.[88] The lack of clear precedent for the CarbonSAFE Rocky Mountain project could complicate permitting efforts.

A CCS operator could obtain a right-of-way to transport or store CO_2 under FLPMA, which gives the BLM broad authority to issue rights-of-way. FLPMA states:

> The Secretary . . . [is] authorized to grant, issue, or renew rights-of-way over, upon, under, or through such lands for . . . such other necessary transportation or other systems or facilities which are in the public interest and which require rights-of-way over, upon, under, or through such lands.[89]

To obtain a right of way from the BLM, a CCS operator would need to meet with the local BLM office, conduct a pre-planning meeting, complete a Standard Form 299 (SF299),[90] and pay a processing fee.[91] If the application is approved, the BLM may require a bond, and the CCS operator would need to pay monitoring fees during development, plus annual rent for the life of the project.

According to employees at the BLM's Utah office, FLPMA could be a means of obtaining a right not only to transport CO_2 across BLM lands but also potentially to use BLM pore space for CO_2 storage (so long as the project is outside of an oil and gas context, such as enhanced oil recovery). Although BLM officials have preliminarily indicated that the FLPMA right-of-way process could possibly be used for CO_2 storage, to date the BLM has not issued any ROW for a project of this nature. Such a first-of-kind ROW grant could be seen by the BLM as having a potential precedent-setting effect, and thus, would likely require input from high-ranking BLM or Department of the Interior officials. This could delay ROW issuance.

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86 43 U.S.C. §§ 1701 *et seq.*

87 30 U.S.C. §§ 181 *et seq.*

88 Our analysis assumes that the sole purpose of the proposed CarbonSAFE Rocky Mountain CCS operator is to sequester CO_2 rather than to engage in further mineral development, such as through enhanced oil recovery.

89 43 U.S.C. § 1761(a)(7).

90 *See* GSA Forms Library, Form: SF299, www.gsa.gov/portal/forms/download/117318 (last visited Aug 14, 2017).

91 *See* Bureau of Land Mgmt., Division of Lands and Realty, *Obtaining a Right-of-Way on Public Lands* (Mar. 10, 2009), www.blm.gov/sites/blm.gov/files/ObtainingaROWPamphlet.pdf.

III. LIABILITY RISK

Any activity involves an element of risk. For the proposed CarbonSAFE Rocky Mountain project, these risks exist for both the transport and storage phases of CCS. With respect to transport, the primary risk is that there will be some kind of accident as CO_2 is being moved. Such an accident could, for instance, harm employees or contractors involved in achieving transport, or the general public or surrounding lands, if a leak occurred. Transport of CO_2 is governed by safety regulations implemented by the Pipeline and Hazardous Materials Safety Administration (PHMSA). This section of the report focuses on that regulation, recognizing that other legal frameworks for liability might apply, particularly under tort law and property law. With respect to geologic storage of CO_2, a host of issues could impact long-term liability exposure. The three main issues are ownership of injected CO_2, permitting requirements for underground injection control under the Safe Drinking Water Act, and long-term liability exposure under other environmental laws. This section addresses each in turn.[92]

A. Transport Regulation

The Pipeline and Hazardous Materials Safety Administration (PHMSA) within the Department of Transportation regulates the movement of a large array of materials via pipeline. This includes CO_2, which PHMSA regulations define as "a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state."[93] PHMSA regulation of CO_2 transport is extensive and focused on ensuring safety and the lack of accidents.[94] Here, we overview six key aspects of these regulations.

1. Minimum Design Requirements

The PHMSA imposes minimum design requirements for new, relocated, replaced, or modified CO_2 pipeline systems. The pipeline must be "made of steel of the carbon, low alloy-high strength, or alloy type that is able to withstand the internal pressures and external loads and pressures anticipated for the pipeline system."[95] If there are segments of the system that operate under different pressure levels, the system must be designed so that components operating at lower pressures will not be overstressed.[96] The system must also account for possible external pressures, such as earthquakes, vibration, and thermal expansion and contraction.[97] All materials in the system also must be chemically compatible with CO_2 and selected for the temperature environment in which the system will operate, maintaining structural integrity.[98] The pipeline also must be designed and constructed to accommodate internal inspection devices.[99]

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[92] Other sources of liability exist, including but not limited to liability for an inadvertent CO_2 release from compression, transport, or injection infrastructure or from the reservoir itself. These issues are treated as the kind of generalized liability that is associated with more routine energy industry development and therefore beyond the scope of this analysis.

[93] 49 C.F.R. § 195.2.

[94] For an overview of regulatory issues of CO_2 transport for CCS, see Jennifer Skougard Horne, *Getting from Here to There: Devising an Optimal Regulatory Model for CO_2 Transport in a New Carbon Capture and Sequestration Industry*, 30 J. LAND RESOURCES & ENVTL. L. 357 (2010).

[95] 49 C.F.R. § 195.112(a).

[96] *Id.* § 195.104.

[97] *Id.* §§ 195.108, 195.112.

[98] *Id.* § 195.102.

[99] *Id.* § 195.120.

2. Construction, Inspection, and Testing

Each phase of pipeline construction and repair must be inspected by a person trained and qualified in the specific aspect of construction.[100] Beginning with initial construction, the operator is responsible for maintaining a complete inspection record for the life of the system.[101] Pipeline location, materials, components, welds, valves, and pumping equipment must all be inspected at the time of installation or construction of each segment. Likewise, breakout tanks must be inspected for adequate emergency venting or pressure relief.[102] Further, no owner may operate a pipeline or return to service any segment unless it has been pressure tested without leakage.[103] The test pressure must be maintained for at least four continuous hours at a pressure equal to 125 percent or more of the maximum operating pressure.[104] The operator must keep records of every pressure test and retain the records as long as the pipeline facility is in use.[105]

3. Operation and Maintenance

Each operator is responsible for the maintenance and safe operation of its pipeline system. If the operator discovers an adverse condition within the system, it must correct the condition within a reasonable time. If the condition presents an immediate hazard, the operator must cease use of the affected part of the pipeline system until it corrects the condition.[106]

The operator must maintain a manual with written procedures for conducting normal operations and maintenance, as well as protocols for abnormal operations and emergencies. The manual must be reviewed and updated annually and kept in locations where operations and maintenance activities are conducted.[107]

Each operator also must keep adequate firefighting equipment at each pump station and breakout tank area, prohibit smoking and open flames, develop and implement a written continuing public education program, establish and conduct a training program for emergency personnel, maintain current maps and records of its pipeline systems, maintain a system of communication for the transmission of information regarding the safe operation of the pipeline system, and place and maintain line markers over each buried pipeline.[108] Signs visible to the public must be maintained around each pumping station and each breakout tank area.[109]

At least 26 times per year, at intervals of no more than 3 weeks, the operator must inspect the surface conditions on or adjacent to each pipeline right-of-way.[110] Operators must also inspect all overpressure safety devices and overfill protection systems at intervals not to exceed 7.5 months, at least twice a year, to ensure that all pressure control equipment is properly functioning, remains in good mechanical condition, and is adequate for capacity and reliability.[111] Repairs must be made in a

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[100] *Id.* § 195.204.
[101] *Id.* § 195.266.
[102] *Id.* § 195.264.
[103] *Id.* § 195.302.
[104] *Id.* § 195.304.
[105] *Id.* § 195.310.
[106] *Id.* § 195.401.
[107] *Id.* § 195.402.
[108] *Id.* §§ 195.403-.404.
[109] *Id.* § 195.434.
[110] *Id.* § 195.412(a).
[111] *Id.* § 195.428.

safe manner so as to prevent damage to persons or property.[112] Each operator must also carry out a written program to prevent damage to pipeline from excavation activities, including blasting, boring, tunneling, backfilling, removal of aboveground structures, and other earth moving operations.[113]

4. Corrosion Control

CO_2 pipeline operators also must comply with PHMSA regulations ensuring against corrosion. Each buried or submerged pipeline must have an external coating for external corrosion control.[114] The coating material must be designed to mitigate corrosion, have sufficient adhesion, be sufficiently ductile, resist damage due to handling and soil stress, and support any supplemental cathodic protection.[115] Each buried pipeline must have cathodic protection in operation no later than one year after the pipeline is constructed as well as electrical test leads for external corrosion control.[116]

Corrosion control must be conducted regularly, with tests for external corrosion at least once every 15 months.[117] Whenever any portion of a buried pipeline is exposed, the operator must examine the exposed portion.[118] Likewise, pipeline interior must be investigated at least every 7.5 months. If corrosion reduces sufficient wall thickness, the pipe must be replaced.[119] When corrosion requiring corrective action is found, the operator must investigate circumferentially and longitudinally beyond the removed pipe to determine that further corrosion does not exist.[120]

Unless electrically interconnected and cathodically protected, all buried pipeline must be electrically isolated from other metallic structures. One or more insulating devices must be installed wherever electrical isolation of a portion of pipeline is necessary to facilitate corrosion control. Each electrical isolation must be inspected and electronically tested to assure the isolation is adequate. If an insulating device is installed in an area where a combustible atmosphere is reasonably foreseeable, precautions must be taken to prevent arcing.[121] Operators must have a program to identify, test for, and minimize damage to pipelines exposed to stray currents.[122]

Records of corrosion control must be maintained. An operator must keep current maps or records showing the location of cathodically protected pipelines, cathodic protection facilities, and neighboring structures bonded to cathodic protection systems. Records of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test must be kept with sufficient detail to demonstrate the adequacy of corrosion control measures for at least 5 years.[123]

5. Annual, Accident, and Safety-Related Reporting

PHMSA regulations require pipeline operators to submit a variety of regular and incident-specific reports. Annual safety reports are due no later than June 15 for each previous year.[124]

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[112] *Id.* § 195.422.
[113] *Id.* § 195.442.
[114] *Id.* § 195.557.
[115] *Id.* § 195.559(a)-(e).
[116] *Id.* §§ 195.563(a), 195.567.
[117] *Id.* § 195.573(a)(1).
[118] *Id.* § 195.569.
[119] *Id.* § 195.585(a).
[120] *Id.* § 195.579(c).
[121] *Id.* § 195.575(a)-(e).
[122] *Id.* § 195.577(a).
[123] *Id.* § 195.589.
[124] *Id.* § 195.49.

Written accident reports, along with updates on the status of an accident, must be submitted within 30 days of the occurrence. Separate reports must be submitted for each failure that results in any (1) unintentional explosion or fire, (2) release of 5 gallons or more of CO_2, (3) death of any person, (4) injury to any person that requires hospitalization, (5) damages estimated to exceed $50,000.[125] In addition to the written report, operators must provide telephonic notice of qualifying accidents as soon as reasonably possible following the discovery of the accident. Accidents that result in the pollution of any stream, river, lake, reservoir, or other similar body of water also requires immediate telephonic notice.[126] If an accident is investigated by PHSMA or other government regulator, the operator has a duty to provide all records, information, and assistance reasonably available or necessary.[127]

6. Qualifications of Pipeline Personnel

Each operator must have and follow a written personnel qualification program that will, among other things, identify covered tasks, evaluate the qualifications of individuals assigned to covered tasks, provide training, allow individuals who are not yet qualified to perform a covered task under supervision of a qualified individual, and communicate changes that affect covered tasks to the individuals responsible for performing those covered tasks.[128] Additionally, each operator must maintain records that contain (1) the identification of qualified individuals, (2) the identification of the covered tasks each individual is qualified to perform, (3) the dates of the individual's current qualification, and (4) the methods of training the individual received. Records of prior/expired qualifications and of individuals no longer performing covered tasks must be retained for 5 years.[129]

B. Storage Liability

Three key issues outline the likely scope of liability for permanently sequestered CO_2. These relate to who owns the CO_2, permitting under the Safe Drinking Water Act, and potential long-term liability under both environmental and other statutory and common law.

1. CO_2 Ownership

A threshold question for possible liability from the storage phase of CCS is who owns the geologically deposited CO_2. That is, once the CO_2 is injected into the ground, does the injector maintain ownership of it and thus risk liability from any harm that may arise from the injected CO_2?

The law is not clear on this question, although analogous reasoning from other areas suggests that an injector of CO_2 is likely to retain title to the gas. Indeed, ownership of injected CO_2 is not a settled issue. It has not been addressed in a published court opinion, and Utah statutory law does not address the question. However, applying property law doctrines from the natural gas context may help delineate ownership of sequestered CO_2.

Two theories have been suggested to address ownership of injected natural gas: the so-called "non-ownership" and "ownership" theories. Under the non-ownership theory, it can be reasoned that once natural gas is injected into the ground, the injector loses ownership of the resource because it is available for anyone to take. This reasoning derives from the longstanding "rule of capture," which serves as the foundation of oil and gas law. The rule of capture holds that, because

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[125] *Id.* § 195.50.
[126] *Id.* § 195.52.
[127] *Id.* § 195.60.
[128] *Id.* § 196.505(a)-(e).
[129] *Id.* § 195.507.

oil and gas are fugitive minerals and can transverse subterranean property boundaries, the first person to reduce that mineral to its possession can claim ownership of it.[130] Building on this idea, which has long been invoked in oil and gas law in part to encourage exploration and extraction, the theory of non-ownership would hold that once the resource—here, CO_2—is injected into the ground, the releaser cannot continue to claim ownership because possession has ceased.[131] The problem with this non-ownership theory is that, in the natural gas context, it has been rejected by all states.[132]

In place of the non-ownership theory, states instead have adopted the ownership theory. Under this theory, "title to natural gas once having been reduced to possession is not lost by the injection of such gas into a natural underground reservoir for storage purposes."[133] The rationale for this theory should be plain. It would be incongruous to promote natural gas extraction under the rule of capture, only to turn around and limit the producing party's incentive to extract by restricting its ability to feasibly store the extracted resource. To reach such holdings, courts have thus distinguished the geological context of injected gas from naturally occurring gas. Whereas the latter can be pulled across property boundaries through extraction techniques, the former is unlike releasing an animal into the wild because there is a "well[-]defined storage field . . . subject to the control of the storage companies[.]"[134] Accordingly, in cases where a gas has previously been reduced to possession but is later injected into a well-defined underground space capable of being maintained with integrity, title to the gas remains with the original owner.

While sequestered CO_2 is distinguishable from natural gas in that the former is part of the waste stream while the latter is an economically valuable commodity, a formidable argument can be made that the ownership theory should also apply to geologically stored CO_2. Because CO_2 is sequestered in a similar manner as natural gas is stored, application of the ownership theory would appear appropriate. Indeed, the mirror image of the policy incentives created by applying the ownership theory to natural gas exist for stored CO_2 as well. For natural gas, the ownership theory preserves the incentive to extract the resource in the first instance. That is, the theory avoids the inequity of a gas producer incurring the cost of extraction but allowing another party to profit from that by taking the gas once it is stored. Similar reasoning could apply in the stored CO_2 context. It would seem incongruous to require the CO_2 owner to incur liability while the CO_2 is above ground but remove the potential of such obligations simply because the CO_2 is moved underground.

Nonetheless, a possible limit on the application of the ownership theory to stored CO_2 might derive from a factual difference between it and natural gas. Injected CO_2 could mineralize within as little as two years, depending upon the medium into which it is injected.[135] This could have significant implications for legal liability, because once the CO_2 turns into a solid, an argument could be made that any possibility of liability should be curtailed since solid rock will not leak or spread.

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130 Westmoreland & Cambria Nat. Gas Co. v. De Witt, 130 Pa. 235, 249 (1889).

131 Hammonds v. Cent. Kentucky Nat. Gas Co., 75 S.W.2d 204, 206 (1934), *overruled by* Texas Am. Energy Corp. v. Citizens Fid. Bank & Trust Co., 736 S.W.2d 25 (Ky. 1987)

132 Mark deFigueiredo, The Liability of Carbon Dioxide Storage 304 (Feb. 2007) (unpublished Ph.D. dissertation, Massachusetts Institute of Technology), http://sequestration.mit.edu/pdf/Mark_de_Figueiredo_PhD_Dissertation.pdf.

133 White v. N.Y. State Nat. Gas Corp., 190 F. Supp. 342, 349 (W.D. Pa. 1960).

134 *Id.* at 348.

135 J.M. Matter et al., *Rapid Carbon Mineralization for Permanent Disposal of Anthropogenic Carbon Dioxide Emissions*, 352 SCIENCE 1312 (2016).

2. *Safe Drinking Water Act Permitting*

The Safe Drinking Water Act (SDWA) requires operators to obtain permits before conducting underground injection of certain materials. The Act relies on a cooperative federalism model whereby the EPA sets minimum standards and states develop programs to attain those objectives in light of local conditions. One such program under the Act is the Underground Injection Control (UIC) program. The UIC program aims to "protect public health and prevent contamination of underground sources of drinking water (USDWs)."[136] The program specifies six classes of well permits that may be granted to inject underground materials subject to the Act. Class VI permits are the relevant permit for CCS operations.

In Utah, the Utah Department of Environmental Quality and the Department of Natural Resources issue Class I-V UIC permits.[137] That is, these state-level agencies have received primacy from the EPA to administer permits for wells within classes I-V. Utah has not petitioned for authorization to administer Class VI UIC permits. That authority rests solely with the EPA. A CCS operator must therefore obtain a Class VI UIC permit from the EPA prior to injecting CO_2.[138]

a. Class VI Well Requirements Under the SDWA

Class VI wells are used exclusively for the injection of CO_2 into the subsurface in aid to a geologic sequestration (GS) or CCS projects. The EPA's main health and environmental concerns regarding CCS are the "[l]arge CO_2 injection volumes associated with GS, the buoyant and mobile nature of the [CO_2 stream], the potential presence of impurities in the CO_2 stream, and its corrosivity in the presence of water."[139] In addition, EPA has expressed concern about the "pressures induced by injection" from CCS, as those pressures "may force naturally occurring salty water (brine) into USDWs, causing degradation of water quality and affecting drinking water treatment processes."[140]

Class VI permits address a wide range of issues: site characterization, computational modeling of the Area of Review (AoR), periodic reevaluation of the AoR, well construction, project monitoring, comprehensive post-injection monitoring and site care, and financial responsibility requirements.[141]

Obtaining and complying with a Class VI permit under the SDWA provides important liability protection for CCS project operators. This liability protection, however, is far from universal and addresses only SDWA liability. EPA regulations make clear that "compliance with a permit during its term constitutes compliance, *for purposes of enforcement*, with Part C of the SDWA."[142] This

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[136] Underground sources of drinking water are defined as "an aquifer or its portion: (a)(1) Which supplies any public water system; or (2) Which contains a sufficient quantity of ground water to supply a public water system; and (i) Currently supplies drinking water for human consumption; or (ii) Contains fewer than 10,000 mg/l total dissolved solids; and (b) Which is not an exempted aquifer." 40 C.F.R. § 144.3 (2017).

[137] Each class of UIC permits covers a different use. Class I deals with industrial and municipal waste. Class II covers enhanced oil recovery, salt water disposal, and storage of hydrocarbons that are liquid at standard temperature and pressure. Class III covers solution mining. Class IV covers hazardous wastes. And Class V covers injection of fluids not covered in other well classes.

[138] 40 C.F.R. § 144.18.

[139] *See* U.S. EPA, *Class VI - Wells Used for Geologic Sequestration of CO_2*, www.epa.gov/uic/class-vi-wells-used-geologic-sequestration-co2#well_def (last visited Sept. 15, 2017).

[140] *Id.* at II(A)(3).

[141] *Id.*

[142] 40 C.F.R. § 144.35 (emphasis added).

rule, commonly referred to as a "permit shield" provision, is echoed in EPA's site closure[143] guidance documents:

> [O]nce an owner or operator has met all regulatory requirements under the UIC program for Class VI wells [at 40 C.F.R. § 146] and the UIC Program Director has approved site closure pursuant to requirements at 40 C.F.R. § 146.93, the owner or operator will generally no longer be subject to enforcement for regulatory noncompliance. However, following site closure, the owner or operator is financially responsible for any remedial action deemed necessary for USDW endangerment caused by the injection operation.[144]

In short, the EPA will not bring enforcement actions under Part C of the SDWA, which addresses protection of USDWs, once a CCS site has undergone official site closure. However, as discussed in more detail below, the rule does not shield enforcement of Part D of the SDWA, which addresses the EPA Administrator's emergency powers to address imminent and substantial endangerment to health. Nor does compliance with Part C preclude other enforcement mechanisms or different kinds of liability. As the above guidance document makes clear, CCS owners/operators remain "financial responsible for any remedial action" that becomes necessary even after site closure.[145] Another portion of EPA's SDWA guidance further reinforces this point:

> [S]ite closure does not eliminate any potential responsibility or liability of the owner or operator under other provisions of law[, or § 1431 of the SDWA[146]]. . . . Furthermore, after site closure, an owner or operator may remain liable under tort and other remedies, or under other federal statutes including, but not limited to, the Clean Air Act (CAA); the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA); and the Resource Conservation and Recovery Act (RCRA).[147]

Stiff penalties may be imposed for violating the SDWA's USDW protections. Violators are subject to civil penalties of up to $25,000 for each day of violation. If the violation was "willful," the violator may also be subject to criminal prosecution and imprisonment of not more than three years.[148]

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143 *See* U.S. EPA, Geologic Sequestration of Carbon Dioxide Underground Injection Control (UIC) Program Class VI Well Plugging, Post Injection Site Care, and Site Closure Guidance (Dec. 2016), www.epa.gov/sites/production/files/2016-12/documents/uic_program_class_vi_well_plugging_post-injection_site_care_and_site_closure_guidance.pdf.

144 *Id.* § 4.4.

145 *Id.*

146 *See id.* Under Section 1431 of SDWA, the Administrator may require an owner or operator to take necessary response measures if he or she receives information that a contaminant is present or is likely to enter a public water system or USDW and may present an imminent and substantial endangerment to the health of persons, and the appropriate state and local authorities have not acted to protect the health of such persons. The action may include issuing administrative orders or commencing a civil action for appropriate relief against the owner or operator of a Class VI well. If the owner or operator fails to comply with the order, he or she may be subject to a civil penalty for each day in which such violation occurs or failure to comply continues.

147 *Id.* (internal citations omitted).

148 42 U.S.C. § 300h-2(b).

b. Lessons Learned from SDWA Permitting for CCS Facilities

We reviewed permitting documents for three other CCS facilities in order to identify lessons learned from those experiences. While the CarbonSAFE Rocky Mountain project will be subject to the same procedural requirements, factual differences between the project at hand and prior CCS facilities need to be acknowledged when considering the experience at other CCS facilities.

1. FutureGen

FutureGen involved CO_2 capture from Unit 4 of Ameren's Meredosia Energy Center, approximately 20 miles west of Jacksonville, Illinois, and was intended to be the world's first full-scale oxy-combustion clean coal repowering of an existing power plant fully integrated with CO_2 transport and permanent geologic storage. CO_2 would have been transported approximately thirty miles from the plant site to the storage location, where approximately one million metric tons per year of compressed and purified CO_2 would have been injected into the Mt. Simon saline formation for a projected twenty-year period.

FutureGen was the first full-scale CCS project in the United States to undergo SDWA Class VI permitting, and twenty-nine parties submitted comments on the draft permit to EPA. After responding to the comments, the EPA issued FutureGen a Class VI permit on March 31, 2014. As the first of such permits issued by the EPA, the agency stated throughout the permit file that particular care was taken to ensure protection of underground sources of drinking water. In addition, the EPA stated that modifications to the permit may be required as the project developed and therefore more data was acquired, despite all of requirements prior to issuing the permit. However, FutureGen 2.0 was discontinued due to funding limitations resulting from the expiration of American Recovery and Reinvestment Act funds on September 30, 2015. Despite the project's failure, the comments received may provide some indication of the kinds of issues that are likely to arise for the CarbonSAFE project.

Notably, the EPA took an exceedingly narrow view of the issues that it needed to consider during the FutureGen 2.0 UIC permitting process, focusing exclusively on protection of USDW. Whether plume migration had ceased prior to closure was oddly considered outside the scope of the permit analysis. Similarly, the EPA took the approach that Class VI rules were not concerned with pore space rights, just safety and project operation. The EPA therefore did not address pore space ownership, concluding that the permit does not prevent private rights from being asserted.

Also, of note, by statute and as acknowledged in the permit, Illinois would have taken ownership of the site ten years after the site closure. Therefore, any long-term liability associated with the project would rest with Illinois. Utah does not have such a statute and it appears that ownership of the site would remain with the operator until it disposes of the site in some way upon site closure. EPA appeared to acknowledge this in issuing the FutureGen 2.0 permit. It stated that "any remediation costs incurred in the very long term (i.e., after the non-endangerment determination and the release from post-injection site care responsibilities) is beyond the scope of the Class VI financial responsibility requirements and the UIC permitting process."

2. ADM

The Archer Daniels Midland Company (ADM) Illinois ICCS project involves sequestration of CO_2 generated as a byproduct of processing corn into ethanol at ADM's biofuels plant adjacent to the storage site in Decatur, Illinois. The CO_2 is collected at atmospheric pressure, compressed, and dehydrated to deliver supercritical CO_2 to the injection wellhead for storage. Injection occurs on a 200-acre site adjacent to the ethanol plant, which is also owned by ADM. While not addressed in detail in permitting documents, it appears that ADM owns the pore space into which the CO_2 would be injected. The project is designed to sequester 2.5 million tons of CO_2 over a 2.5-year period.

On May 3, 2011, the Department of Energy concluded its NEPA analysis[149] for the ADM project and issued a Finding of No Significant Impact.[150] The ADM project received the U.S. EPA's UIC Class VI injection well permit effective March 6, 2017 and started commercial operations accordingly. ADM characterized the CO_2 streams generated by this project as liquids, supercritical fluids, or gas. It will be injected into the Mount Simon at depths between 5,553 feet and 7,043 feet.

Class VI injection well permitting appeared to generate very little controversy, with only one member of the public submitting comments on the draft permit. Most relevant to the CarbonSAFE project, the commenter asserted that pore space rights must be taken into account when issuing the permit. The EPA, however, responded that under Class VI rules, it need not consider pore space rights, and the permit does not grant any real property rights. As noted above, CarbonSAFE Rocky Mountain would be wise to anticipate a higher level of scrutiny and that other federal approvals will need to address pore space ownership, even if the EPA does not address the issue directly.

3. Potential Liability Outside of SDWA Part C

As noted, SDWA Part C addresses protection of USDWs. SWDA Part D addresses the EPA Administrator's authority to respond to imminent and substantial threats to public health. Because compliance with a Class VI well permit does not act as a complete shield to liability,[151] it is important to understand how other types of liability may arise. Although not exhaustive, there are three key areas to consider: other provisions of the SDWA, RCRA and CERCLA, and the common law.

a. <u>SDWA Part D</u>

Section 1431 of the SDWA authorizes the EPA to take action against a CCS operator upon a finding of an "imminent and substantial endangerment to the health of persons" where "appropriate State and local authorities have not acted to protect the health of such persons."[152] The statute refers to this authority as "[e]mergency powers." The actions that EPA may take include but are not limited to:

> (1) issuing such orders as may be necessary to protect the health of persons who are or may be users of such system (including travelers), including orders requiring the provision of alternative water supplies by persons who caused or contributed to the endangerment, and (2) commencing a civil action for appropriate relief, including a restraining order or permanent or temporary injunction.[153]

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[149] U.S. Dep't of Energy, Final Environmental Assessment of Industrial Carbon Capture and Sequestration (ICCS) Area 1 Project, "CO_2 Capture from Biofuels Production and Sequestration into the Mt. Simon Sandstone," Archer Daniels Midland Company Decatur, Illinois (2011).

[150] U.S. Dep't of Energy, Finding of No Significant Impact for Archer Daniels Midland Company's "CO_2 Capture from Biofuels Production and Sequestration into the Mt. Simon Sandstone," Decatur, Illinois (2011).

[151] *See* 75 Fed. Reg. 77230, 77270 (Dec. 10, 2010); *see also* Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Well Plugging, Post Injection Site Care, and Site Closure Guidance (Dec. 2016), *available at* www.epa.gov/sites/production/files/2016-12/documents/uic_program_class_vi_well_plugging_post-injection_site_care_and_site_closure_guidance.pdf.

[152] 42 U.S.C. § 300i.

[153] *Id.*

If EPA does issue an order under this provision, failure to comply with the order may result in civil penalties of up to $15,000 per day of noncompliance.[154]

b. RCRA / CERCLA

Because CO_2 streams that may be used for geologic sequestration are likely to contain impurities, there is a risk that a contaminated CO_2 stream may be considered toxic or hazardous waste regulated under the Resource Conservation and Recovery Act (RCRA). There is also a risk that, depending on the scope of any environmental contamination caused by impurities in the CO_2, liability could arise under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA or Superfund).[155] Industry specifically raised this concern to EPA during the rulemaking process for UIC Class VI wells, but EPA chose not to address the issue there.[156]

Instead, in a separate rulemaking,[157] EPA clarified that CO_2 injected underground for CCS purposes will not create RCRA liability so long as certain conditions are followed. In adopting this rule, EPA specifically acknowledged the need for CCS industry certainty, noting that its objective is to "substantially reduce the uncertainty associated with defining and managing . . . CO_2 streams under RCRA subtitle C and [to] facilitate the deployment of GS."[158]

In order to qualify for RCRA liability exclusion under this rule, CCS owners and operators must comply with four key conditions:

> (1) Transportation of the carbon dioxide stream must be in compliance with U.S. Department of Transportation requirements, including the pipeline safety laws and regulations of the U.S. Department of Transportation, and pipeline safety regulations adopted and administered by a state authority pursuant to a certification, as applicable.
>
> (2) Injection of the carbon dioxide stream must be in compliance with the applicable requirements for Class VI Underground Injection Control wells, including the applicable requirements;
>
> (3) No hazardous wastes shall be mixed with, or otherwise co-injected with, the carbon dioxide stream; and
>
> (4)(i) Any generator of a carbon dioxide stream, who claims that a carbon dioxide stream is excluded under this paragraph (h), must have an authorized representative sign a certification.[159]

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154 *Id.* § 300i(b).

155 In broad terms, RCRA governs handling and disposal of hazardous and toxic wastes. CERCLA governs liability for cleanup of the nation's most polluted sites.

156 Hazardous Waste Management System: Conditional Exclusion for Carbon Dioxide (CO_2) Streams in Geologic Sequestration Activities, 79 Fed. Reg. 350-01 (Jan. 3, 2014).

157 *Id.*

158 *Id.*

159 40 C.F.R. § 261.4; *see also id.* § 261.4(h)(4).

Thus, under RCRA, a CO_2 stream that is connected to coal power plant will not be considered waste for RCRA purposes as long as the CCS owner and operator complies with all relevant regulations.

Presumably, the EPA's Conditional Exclusion Rule also should remove the specter of CERCLA liability for CCS operators. This is because of how CERCLA liability attaches. In broad terms, CERCLA liability attaches when there is a "release of a hazardous substance, from a facility, that results in response costs."[160] CERCLA categorically defines hazardous waste as "any hazardous waste having the characteristics identified under or listed pursuant to RCRA.[161] Because EPA's rule excludes CO_2 streams from RCRA so long as the specified conditions are met, CERCLA liability also presumptively should be precluded because the CO_2 stream would not meet the definition of hazardous waste under RCRA, and thus, CERCLA.

c. Common Law

The United States has a long and rich tradition of judicially made law (now, often codified) that may give rise to liability. This is typically referred to as the "common law." The two most prominent areas in this regard are property law and tort law. These generally are areas of state law, and vary from jurisdiction to jurisdiction, although some federal common law also exists.

Accordingly, this section discusses several causes of action that may give rise to liability under common law theories for CCS operation. In particular, we address five key areas of common law: trespass, nuisance, negligence, negligence per se, and strict liability.

All of these causes of action require a judge (and/or jury) to balance the interests of CCS operation and CO_2 sequestration with the harm or harmful conduct alleged. Currently, there is no judicial precedent declaring the importance of CCS, and the exact harms that could occur are still speculative. Another relevant factor is the interaction of federal and state law. Generally, under the Supremacy Clause of the U.S. Constitution, federal law trumps state law. Parties to disputes sounding in common law thus regularly invoke federal law as a way to seek to defend against potential liability. As more federal legislation arises in the context of CCS, the availability of such defenses—referred to as "preemption"—could also arise, just as the imposition of federal standards of care may give rise to new legal theories for litigants. Further, when statutes of limitation bar claims will impact when and under what conditions liability for CCS projects may arise, especially for the sequestration phase of CCS.

Numerous courts also recognize that a tort defendant's compliance with regulatory requirements can provide a defense to certain tort or personal injury claims. Generally, however, a party whose conduct comports with regulatory requirements is not automatically protected from tort liability for harm resulting from that conduct. Rather, regulatory compliance is treated as non-conclusive evidence of an actor's non-negligent conduct.[162]

1. Trespass

In the context of CCS, trespass may occur either when transported CO_2 (and the other chemicals it contains) contaminates the surface or subsurface estate owned by another entity. Because the quantity of injected CO_2 is vast, and how long the CO_2 remains mobile underground depends on myriad factors, there is a chance that CO_2 may migrate beyond acquired property interests. In that case, there may be actionable trespass claims against a CCS operator.

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160 Alexandra B. Klass & Elizabeth J. Wilson, *Climate Change and Carbon Sequestration: Assessing a Liability Regime for Long-Term Storage of Carbon Dioxide* 58 EMORY L.J. 103 (2008).

161 42 U.S.C. § 9601(14).

162 THOMAS A. DICKERSON ET AL., 2 LAW OF TOXIC TORTS § 11:5.20 (2017).

Applying analogous principles from oil and gas law helps clarify the potential extent of such liability for trespass. Scholars have identified two factors that may limit a cause of action for trespass in the oil and gas context: (1) ascertaining actual damages and (2) overcoming public policy that favors the trespass.[163]

First, ascertaining actual damages could be difficult, largely because of the fact that everything takes place deep beneath the surface. Thus, in the absence of catastrophic releases of stored CO_2, adjacent subsurface owners would most likely be unable to detect any trespass. Further, when the trespass is detected, plaintiffs typically bear the burden of proving their damages.[164] Therefore, a CCS operator should only anticipate trespass liability where there are "reasonably foreseeable" competing uses proximate to the CO_2 plume, such as natural gas extraction or storage.[165]

Second, even if damages are capable of being ascertained and proven, courts weigh public policy against property law concerns.[166] This is particularly true in the oil and gas context, because many states have laws on the books specifically promoting the extraction of these resources. By contrast, state policy favoring CO_2 sequestration is much less established. Moreover, courts are less likely to weigh the public interest in cases of imminent danger to public health, because the damage is readily ascertainable, and the fundamental purpose of tort law is to redress private injury.[167]

2. Nuisance

Nuisance actions arise even when there has been no physical trespass and the operator is in full regulatory compliance. Two different types of nuisance theories exist at common law: private nuisance and public nuisance. They differ as follows:

> A public nuisance is an unreasonable interference with a right common to the general public and may only be asserted by a public body (such as a state or local government) or by a private party who has suffered a unique or special injury that differentiates his or her harm from that suffered by the general public. A private nuisance is a nontrespassory invasion of another's interest in the private use and enjoyment of land and may be brought by anyone with an ownership or possessory interest in land.[168]

Generally, under either theory, a cause of action sounding in nuisance arises when "the invasion of the private use and enjoyment of land [is] (1) intentional and unreasonable or (2) unintentional but negligent, reckless, or subject to strict liability because it is an abnormally dangerous activity."[169] Once a cause of action in nuisance is shown, the question then becomes how to compensate the harmed party for it. In this regard, "the court balances the benefits of the alleged nuisance activity, the harm to the plaintiff and others, and other equitable factors to determine

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163 *See* Klass & Wilson, *supra* note 160, at 135.

164 *See, e.g.*, Raymond v. Union Texas Petroleum Corp., 697 F. Supp. 270, 274 (D. La. 1988); *see also* Mongrue v. Monsanto Co., No. 98-2531, 1999 WL 970354 (E.D. La. 1999).

165 Chance v. BP Chems., Inc., 670 N.E.2d 985, 992 (Ohio 1996).

166 *See* Klass & Wilson, *supra* note 160, at 135.

167 *Id.*

168 *Id.* at 139. (internal quotations and citations omitted).

169 *Id.* (internal quotations and citations omitted).

whether the defendant should pay damages to the plaintiff or whether the plaintiff is entitled to enjoin the conduct causing the nuisance.[170]

Nuisance liability could occur in ways similar to how trespass liability might arise. If a CCS operation contaminates (or forecloses or limits use of land) underground drinking water, soil or other surface resources, or subsurface resources, nuisance liability may exist. As with each of the common law liability theories at issue here, the resulting response from a court could include monetary damages and/or an injunction prohibiting future activities (or dictating how they proceed).

3. *Negligence*

A CCS operator potentially may be liable under common law theories of negligence as well, during both the transport and storage phases of the project. In general, negligence occurs when, by a preponderance of the evidence, a plaintiff shows that a

> defendant owed a duty of care to the plaintiff, that the defendant breached that duty of care, that the defendant's breach of the duty was the actual and proximate cause of the plaintiff's harm, and that the plaintiff suffered damages (based on injury to person or property) as a result of the defendant's conduct.[171]

For many types of activities, duties of care are well-settled. For more novel activities, it can take some time for the law to coalesce around what, precisely, the duty of care is. Typically, the duty of care calculation weighs the utility of a defendant's action against its risk. Also taken into consideration is how reasonable the defendant's actions were.[172] Because CO_2 transport is well-established and governed heavily by extant regulations, violations of those regulations likely would be considered a breach of the duty of care for purposes of negligence. By contrast, because the storage portion of CCS operations is more novel, plaintiffs may have an uphill battle demonstrating what level of care is required in, for example, selecting a site, injecting CO_2, ensuring its safe sequestration, and monitoring it for decades.[173] Of course, compliance with the terms of permits for these activities is at least some evidence of reasonableness, although it is not conclusive. Another key issue for CCS is proving who caused the damage in question. Because that could be difficult if there is more than one CCS operation underway in the same formation, plaintiffs, as with trespass, may face evidentiary challenges if they choose to bring a negligence claim. This issue runs to the heart of any claim for relief under a negligence theory, particularly if harm is difficult to quantify or monetize.

4. *Negligence Per Se*

A plaintiff may also bring an action under a theory of negligence per se. "Under negligence per se, a plaintiff can establish negligence if he or she can show that the defendant violated a statute 'designed to protect against the type of accident the actor's conduct causes and if the accident victim is within the class of persons the statute was designed to protect.'"[174] The UIC rules, promulgated under the SDWA, would likely fall into this category. It is possible that other applicable Utah statutes also could give rise to negligence per se liability. Such a liability theory would provide a more

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[170] *Id.* (internal quotations and citations omitted).

[171] *Id.* at 136 (quoting 1 DAN B. DOBBS, THE LAW OF TORTS § 114, at 269-70 (2001)).

[172] *See* RESTATEMENT (SECOND) OF TORTS § 291.

[173] *See, e.g.*, N.J. Dep't of Envtl. Prot. v. Ventron Corp., 468 A.2d 150 (N.J. 1983).

[174] Klass & Wilson, *supra* note 160, at 138 (quoting RESTATEMENT (THIRD) OF TORTS § 14 (Proposed Final Draft 2005)).

convenient path for plaintiffs, although they may face the same evidentiary challenges in bringing this cause of action as they would under a standard theory of negligence.[175]

5. Strict Liability

Strict liability attaches when a project involves abnormally dangerous activities. Utah applied the *Rylands* test in *Branch v. W. Petroleum, Inc.*[176] and imposes strict liability when an operator "engages in a 'non-natural' or 'abnormal' use of the land which results in harm."[177]

Whether a CCS operator could be held strictly liable for their actions in uncertain. Klass and Wilson analyzed use of strict liability theories and concluded that such liability has been found applicable over time to "a broad range of activities."[178] These include, for example, contamination of groundwater via petroleum products, release of "toxic wastes from . . . industrial operations," and contamination of adjacent property with polychlorinated biphenyl (PCBs).[179] A strong argument can be made that CCS is a non-natural or abnormal land use, though abnormality may be somewhat more difficult to prove in areas undergoing extensive EOR. As with the tort remedies discussed above, strict liability could be an attractive path for plaintiffs, provided that plaintiffs can overcome the requirements to establish that the harm they experienced was caused by the operator.

C. Managing Financial Risk and Long-Term Liability

Risk exposure is a function of the likelihood of harmful event combined with the consequences of such an event, both of which are influenced by numerous site-specific factors. In this section, we treat financial risk as the economic cost of mitigating the injuries caused by a harmful event as well as compensation for unmitigable injuries associated with any such event. For purposes of risk assessment, CCS operations can be broken into four discrete phases: (1) capture, (2) transport, (3) injection and CO_2 plume stabilization, and (4) post-closure stabilization and monitoring. This analysis focuses on the transport, injection and CO_2 plume stabilization, and post-closure stabilization and monitoring phases.

Events giving rise to financial liability could take many forms, the most likely of which involve damage caused by: (1) the puncture of a CO_2 pipeline or failure of other pipeline infrastructure, (2) seismicity induced by CO_2 injection, (3) ground surface damage or surface heaving caused by injected CO_2, (4) interference with a surface owner's rights to occupy or use the ground surface (trespass), (5) interference with a sub-surface owner's rights to occupy or use the sub-surface, or infringement with development of their mineral rights (trespass on minerals), (6) contamination of an underground source of drinking water or other water source, and (7) an atmospheric release of CO_2. Loss of CO_2 containment and failure to maintain permanent

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175 For a thorough discussion of negligence per se and environmental regulations, see Alexandra B. Klass, *Common Law and Federalism in the Age of the Regulatory State*, 92 IOWA L. REV. 545, 585 (2007).

176 657 P.2d 267 (Utah 1982). *W. Petroleum* dealt with an oil well water disposal service, which disposed of formation water in ponds adjacent to plaintiffs' farm. The court held the defendant strictly liable for pollution of subterranean water system that fed plaintiffs' culinary wells, determining that liability could be based on the theory that ponding of toxic formation water in an area adjacent to the wells constituted an abnormally dangerous and inappropriate use of the land.

177 *See id.* at 141 (quoting W. PAGE KEETON ET AL., PROSSER AND KEETON ON THE LAW OF TORTS § 75, at 534 (5th ed. 1984)).

178 Klass & Wilson, *supra* note 160, at 142.

179 *Id.* For a full discussion of strict liability cases, see generally Alexandra B. Klass, *From Reservoirs to Remediation: The Impact of CERCLA on Common Law Strict Liability Environmental Claims*, 39 WAKE FOREST L. REV. 903, 942-961 (2004).

sequestration, as required by regulation or contract, could also require the operator to refund payments received for sequestration. Damage to property, damage to natural resources or livestock, and injury to humans also involve potential economic costs to an operator.

The risk profile for each stage of operation underpins the range of costs and loss values associated with potential mitigation, remediation, and, as necessary, compensation for damages. The risk profile is a function of numerous phase-specific considerations. With respect to CO_2 transport, pipeline length, period of pipeline operation, CO_2 pressure, CO_2 purity, and proximate land use activities are examples of factors that could contribute to the risk associated with an unintended release. The location of an unintended release of CO_2 could also directly impact the consequences of such a release. A CO_2 release would be more likely to cause injury or property damage if it occurred in a populated area, for example.

During the injection and plume stabilization phase, the volume of CO_2 injected, the injection pressure, the length of the injection period, the geology of the receiving formation, the number and integrity of other wells penetrating the receiving formation, and the existence of underground sources of drinking water or valuable minerals all contribute to the risk profile. As with the risk profile associated with CO_2 transportation, the proximity to populated areas is also a critical factor in assessing risk. This necessarily requires consideration of current population as well as anticipated population growth.

Many of the same factors that shape injection and plume stabilization period risks impact the risk profile during the post-closure and post-CO_2-plume-stabilization period. However, in contrast to the risk profile during the injection and stabilization phase, which increases with injection volume and pressure until stabilization occurs, the post-stabilization and closure risk profile is likely to decline[180] as reservoir pressures stabilize, plume migration slows or stops, and as CO_2 reacts with brine and minerals in the rock to form bicarbonate that permanently traps that portion of the injected CO_2, as shown in Figure 2.[181]

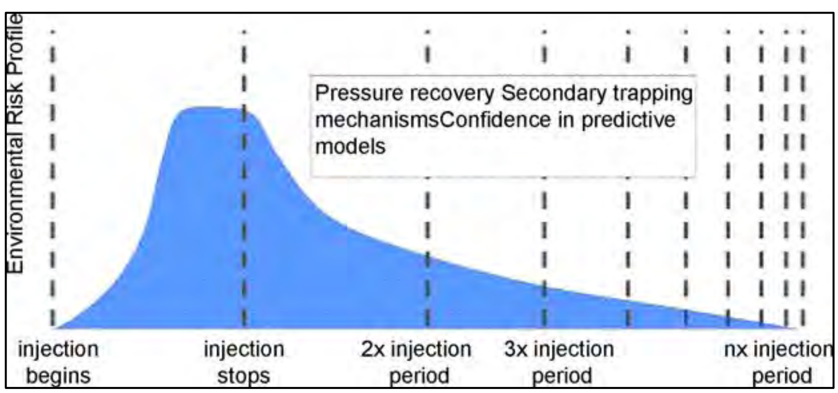

Figure 2. Life-Cycle Risk Profile for Geologic CO_2 Storage[182]

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[180] *See, e.g.*, James J. Dooley et al., *Design Considerations for Financing a National Trust to Advance the Deployment of Geologic CO_2 Storage and Motivate Best Practices*, 4 INT'L J. GREENHOUSE GAS CONTROL 381, 382 (2010).

[181] For a summary of CO_2-trapping mechanisms, see National Energy Technology Lab, U.S. Dept. of Energy, *How Is CO_2 Trapped in the Subsurface?*, https://www.netl.doe.gov/research/coal/carbon-storage/carbon-storage-faqs/how-is-co2-trapped-in-the-subsurface (last visited Apr. 25, 2018).

[182] Figure 2 is from S.M. Benson, *Multi-Phase Flow and Trapping of CO_2 in Saline Aquifers* (Paper No. OTC 19244) in PROCEEDINGS OF 2008 OFFSHORE TECHNOLOGY CONFERENCE (2008).

Other factors further underscore how quantifying CCS financial risks necessarily requires site-specific risk assessments. Reservoir size and permeability, injection volume and pressure, CO_2 stream purity, structural geology, faulting and reservoir perforations (including existing and abandoned wells), proximity to groundwater, proximity to valuable mineral resources, proximity to populated areas, proximity to sensitive surface resources, and pipeline length are all examples of the kinds of factors that must be considered on a case-by-case basis. Should the CarbonSAFE Rocky Mountain project proceed past Phase I, then, a quantitative risk assessment specific to the project, taking into account this site-specific information, would be necessary.

While a precise quantification of financial risk for the CarbonSAFE Rocky Mountain project is not currently possible, a review of other CCS projects may provide a rough indication of the scale of financial risk at hand. A 2011 study in ENERGY PROCEDIA provides preliminary estimates of potential public health damages during the operational phases at three proposed FutureGen sites: Tuscola, Illinois; Jewett, Texas; and Odessa, Texas.[183] As the authors explain:

> [A]ll three sites are in highly rural areas and have favorable geologic and geographic characteristics that result in relatively low damages relative to the expected cost of these facilities. Notably, the Odessa damages estimate is particularly low, reflecting the near absence of human receptors near the plant site, CO_2 pipeline, and sequestration site.[184]

Specifically, damage estimates ranged from $50,000 to $7,400,000. These estimates equate to less than $0.20 per ton of CO_2, assuming a 50-year injection period and 50 million metric tons of CO_2 stored per site. Critically, however, these valuation estimates are limited to valuation of events arising during the operational period through a defined post-injection period for each site. It is also important to note that these estimates relate only to damages associated with injuries involving public health and do not contemplate damages associated with environmental resources, such as groundwater or atmospheric releases of CO_2.

A 2014 study involving two of the same authors and also published in ENERGY PROCEDIA used a risk-based probabilistic model to estimate several categories of potential financial damages on a site-specific basis.[185] This model estimated the financial consequences arising from potential human health, safety, environmental, and business interruption events associated with CCS, in light of their anticipated site-specific likelihood and magnitude.

The authors utilized this model to quantify financial risk at the Alabama Gulf Coast-Plant Barry pilot project in Mobile, Alabama based on forty-eight potential site-specific CCS-related events at the site. The authors contemplated two scenarios: an "experimental injection well" that operated for nine years and a theoretical commercial injection well that operate for 103 years (including ten years of post-injection monitoring). Damages under the experimental injection well scenario were estimated to range up to $27 million, with a median damage estimate of $3.3 million.[186] The five events contributing the highest potential damage for the experimental scenario were:

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[183] Michael Donlan & Chiara Trabucchi, *Valuation of Consequences Arising from CO_2 Migration at Candidate CCS Sites in the U.S.*, 4 ENERGY PROCEDIA 2222 (2011).

[184] *Id.* at 2228.

[185] Chiara Trabucchi et. al, *Application of a Risk-Based Probabilistic Model (CCSvt Model) to Value Potential Risks Arising from Carbon Capture and Storage*, 63 ENERGY PROCEDIA 7608 (2014).

[186] *Id.* at 7612.

- Failure to maintain sustained operation of capture unit, pipeline, and injection to enable storage of sufficient volumes of CO_2 (100-300 kt) to meet project goals;
- Unexpected transport requirements;
- Monitoring program unable to meet monitoring intents due to movement of CO_2 and demonstration of containment;
- Decreased performance of capture unit based on fuel switch; and
- Injection pump failure or downtime.

Together, these five categories of events represented 66.5 percent of total costs across all model runs.[187]

Modeling for the commercial scenario produced damage estimates of up to \$131 million, with a median damage estimate of \$6 million. The five events contributing to the highest potential damage estimated under the commercial scenario were:

- Monitoring program unable to meet monitoring intents due to movement of CO_2 and demonstration of containment;
- Unexpected transport requirements;
- Unexpected size of plume expansion (larger than anticipated) triggering permit review, expanded monitoring activities, and implementation of preventive measures on wells;
- Loss of containment due to migration along transmissive faults; and
- Return of low quality condensate that could impact water chemistry and cause problems at the plant.

Together, these five categories of events represented 83.7 percent of the total costs across all model runs.[188] The authors also compared the cost per ton of sequestered CO_2 to those projected for the non-selected FutureGen site in Jewett, Texas, as shown in Figure 3.

Category	Commercial Well Scenario - Plant Barry				Non-Selected FutureGen Site Jewett, TX
	30-Year Post-Injection Monitoring		10-Year Post-Injection Monitoring		
	All Events	Business Risks Excluded	All Events	Business Risks Excluded	
Minimum $/ton cost	$0.00	$0.00	$0.00	$0.00	$0.00
50th percentile $/ton cost	$0.17	$0.12	$0.12	$0.07	$0.17
95th percentile $/ton cost	$1.05	$1.01	$0.92	$0.88	$0.37
99th percentile $/ton cost	$1.54	$1.49	$1.36	$1.32	$0.48
Maximum $/ton cost	$2.67	$2.85*	$2.63	$2.56	$0.74

* All Monte Carlo simulations across scenarios were conducted independently. In this case, the highest-cost trial for the "business risks excluded" scenario exceeded the costs of the highest-cost trial for the scenario where no events were excluded. This outcome has a very low probability of occurrence. $/ton assume 50MM tons CO_2 injected.

Figure 3. Cost Per Ton Summary
Model Outputs for Commercial Well Scenario
and Non-Selected FutureGen Site in Jewett, TX[189]

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[187] *Id.*
[188] *Id.*
[189] Figure 3 is from Trabucchi et al., *supra* note 185.

While the costs and risks associated with the CarbonSAFE Rocky Mountain project will undoubtedly differ from those associated with either the Plant Berry or Jewett, Texas facilities, it seems reasonable at this preliminary phase to plan for financial risks in the range of $1.00 to $1.50 per ton of CO_2 injected. This represents approximately the ninety-fifth to ninety-ninth percentile for the Plant Berry Facility and is more than the estimate for the Jewett, Texas site.

Insurance for CCS operations needs to consider all of the risks associated with more traditional industrial operations as well as the risks associated with long-term sequestration. Insurance markets for post sequestration and stabilization liability remain undeveloped. The possibility of open-ended liability—including the potential for a large payout—has discouraged investment in this area, as has the slow development of commercial scale CCS facilities. There may also be a mismatch between the real and perceived risk profile for long-term CCS, as reservoir pressures are anticipated to decrease over time, especially given that CO_2 is likely to react with brine and minerals in the rock to form bicarbonate and permanently trap a significant portion of the injected CO_2. This may, in turn, result in reliance on less accurate analogues for insurance model development.

Legislation at either the state or federal level that assumes long-term responsibility once injection has ceased and the CO_2 plume has stabilized may help in addressing these issues. This is what Congress has done for other industries, including, for example, for the nuclear power industry through the Price-Anderson Act. Otherwise, operators may need to explore more creative ways of developing insurance options.

IV. FEDERAL ENVIRONMENTAL IMPACT REVIEW

The National Environmental Policy Act (NEPA)[190] has been described as the Magna Carta of environmental laws.[191] Notably, however, the law does not require the federal government to do anything substantive with respect to the environment. Rather, the statute requires the government to consider what impact different actions that it takes will have on the environment before taking those actions. The idea is that NEPA facilitates federal agencies making informed decisions because they consider the consequences of various alternative courses of action before proceeding. Indeed, NEPA does not require selection of the least damaging alternative, only that agencies take a hard look at tradeoffs before moving forward. Where an action involves approvals from multiple agencies, those agencies can combine their NEPA analyses. While several states have adopted state environmental policy acts that involve procedural mandates similar to NEPA, Utah is not one of those states.

A. The NEPA Process

NEPA requires that, prior to authorizing or undertaking any "major Federal action significantly affecting the quality of the human environment," the lead federal agency must analyze the likely impacts of that action on the environment. This often results in a detailed statement discussing the purpose and need for the proposed action, alternative means of satisfying the purpose and need, and the environmental impacts that are anticipated to result from each considered alternative, including an alternative of "no action."[192] Under NEPA, the "human environment" is defined broadly to include "the natural and physical environment and the relationship of people with

[190] 42 U.S.C. §§ 4321–4370(h).
[191] DANIEL R. MANDELKER, NEPA LAW AND LITIGATION § 1:1 (2d ed. 2014).
[192] 42 U.S.C. § 4332(2)(C).

that environment."[193] Major federal actions typically include the issuance of project permits, such as mineral leases on federal lands.

Not all federal actions have a "significant" impact, and the scope and intensity of impacts associated with the proposed action determine the level of analysis required. Where impacts are "significant" in both their context and intensity, an Environmental Impact Statement (EIS) is required. "Context" varies by project and is evaluated at multiple scales.[194] "Intensity" may reflect a wide array of factors, including but not limited to controversy surrounding the nature of the effects[195] and the degree to which the action may establish a precedent for future actions with significant effects.[196]

Where the significance of impact is uncertain, the lead federal agency may elect to prepare either an EIS or a less onerous Environmental Assessment (EA).[197] If the agency chooses the latter path and the EA shows that the impacts are significant, then the agency must prepare a full-fledged EIS. If, however, the EA shows that the impacts are not significant, the agency may issue a finding of no significant impact (FONSI) and a record of decision (ROD) on that determination.

Agencies are also authorized to promulgate regulations identifying categories of action that "do not individually or cumulatively have a significant effect on the human environment."[198] Agencies can then categorically exclude these actions from further NEPA review. However, even if a categorical exclusion (CE) has been established by rule, the existence of "extraordinary circumstances" may prevent its application.[199] Under Department of Energy regulations, certain small-scale CO_2 injection wells are categorically exempt from NEPA analysis.[200] CarbonSAFE, however, is likely to inject more than the 500,000-ton limit allowed under these regulations.

EISs are part of an iterative analytical decision making process that begins with publication of a Notice of Intent (NOI) to prepare an EIS.[201] The NOI kicks off a public scoping period in which the public is invited to submit comments about the proposal, the environmental issues the proposal raises, and potential alternative means of achieving the purpose of the proposed action.[202] Those comments help the lead federal agency identify issues, formulate alternatives, and collect or conduct necessary research. The reasonably foreseeable direct, indirect, and cumulative impacts anticipated to result from implementation of each alternative (including a "no action alternative") are then analyzed and disclosed in a Draft EIS (DEIS).[203] The DEIS is made available for public review and comment.[204] After considering public input, the lead federal agency releases a Final EIS (FEIS) that reflects public input on the agency's methods and analysis.[205] Following a period in which the governor of the state within which the project occurs can comment on consistency with state requirements, the lead federal agency then issues a ROD stating the agency's decision and initiating a protest or appeals period.[206] Figure 4 details this process.

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[193] 40 C.F.R. § 1508.14.
[194] *Id.* § 1508.27(a).
[195] *Id.* § 1508.27(b)(4).
[196] *Id.* § 1508(b)(6).
[197] *Id.* § 1508.9.
[198] *Id.* § 1508.4.
[199] *Id.* § 1508.4.; *see e.g.*, 43 C.F.R. § 46.215 (2017) (listing extraordinary circumstances for BLM NEPA).
[200] 10 C.F.R. § Pt. 1021. Subpt. D App. B § B5.13 (2017).
[201] 40 C.F.R. § 1501.7.
[202] *Id.* § 1501.7(a).
[203] *Id.* §§ 1502.9(b), 1508.8.
[204] *Id.* § 1503.1(a)(4).
[205] *Id.* § 1502.9(b).
[206] *Id.* § 1505.2.

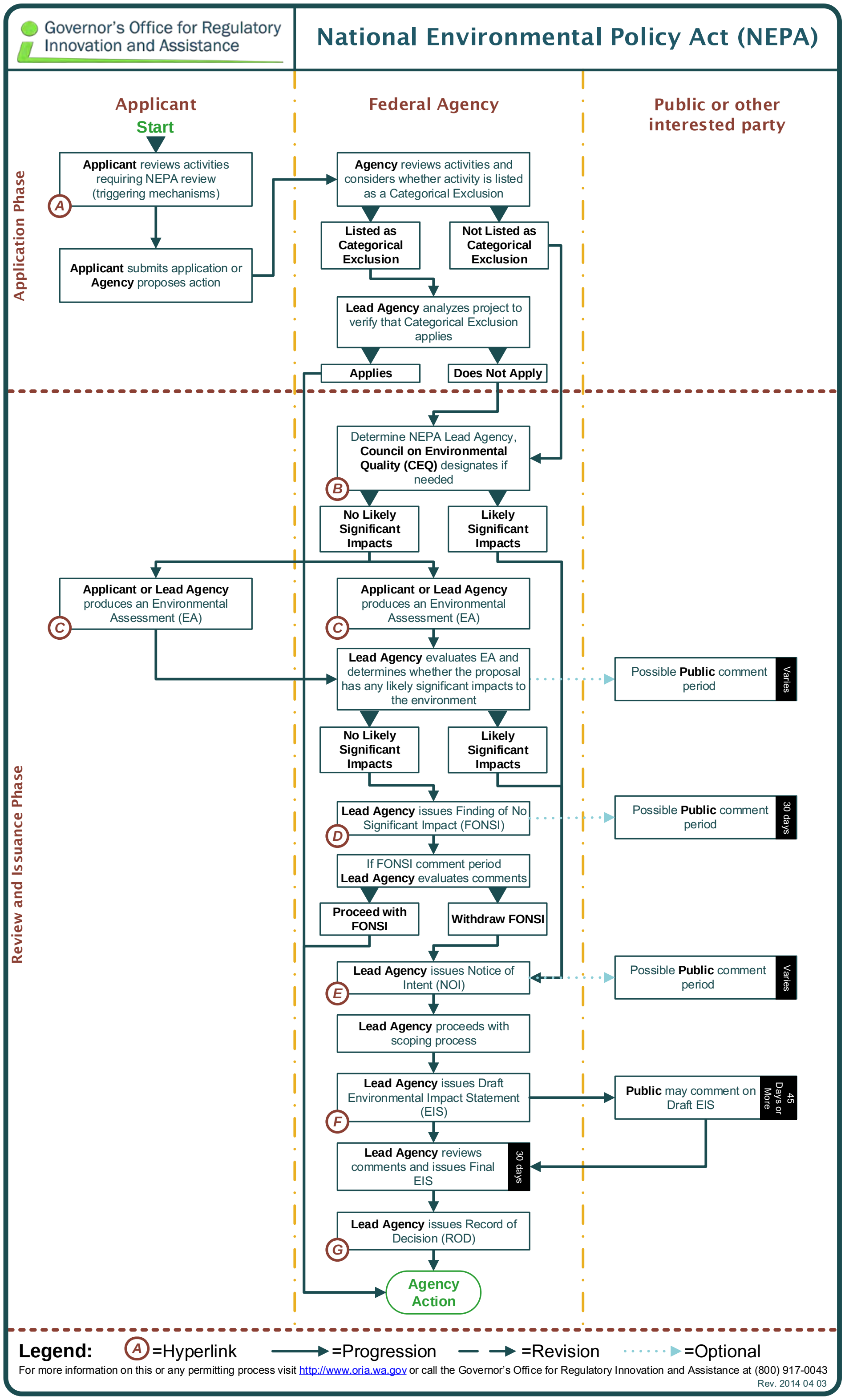

Figure 4. The NEPA Process[207]

Agencies are directed not to speculate when conducting their NEPA analysis, and therefore frequently choose to undertake a phased approach to NEPA implementation. The BLM, for example, may undertake a NEPA analysis as part of a planning-level decision to determine which lands are available for oil and gas development and which surface use stipulations will apply to those broad areas. Not all lands that are available for leasing will be of interest to industry, and the BLM may therefore need to review or update NEPA determinations in response to an expression of interest prior to leasing an individual parcel, if project-scale information was not considered at the multi-million-acre planning scale. The BLM may also need to conduct NEPA reviews on, for instance, the actual development of the well or well field if the viability of the field, the number of wells, likely field and pipeline layouts, or other associated impacts that were not discernable at the time of leasing. The federal agency, however, cannot segment one project into its component parts in order to reduce the level of analysis required under NEPA.[208]

B. NEPA Considerations for the CarbonSAFE Rocky Mountain Project

Multiple federal actions associated with the CarbonSAFE Project are likely to trigger NEPA review. If the CO_2 plume is anticipated to migrate into pore space that is under federal ownership or control, issuance of a federal lease to utilize the pore space will likely require NEPA analysis by the Bureau of Land Management. If the injection well compressors, pipelines, or other infrastructure are located on federal lands, obtaining rights to use these lands (leases or rights-of-way) will also require NEPA review. Issuance of federal permits that may be required by other laws may also require analysis under NEPA, including, potentially, for a CCS pipeline.[209] Finally, future funding of project implementation by the Department of Energy would also likely require NEPA analysis.[210]

Notably, Class VI injection well permitting, which is conducted by the EPA and occurs pursuant to the Safe Drinking Water Act, is likely exempt from NEPA review. Safe Drinking Water Act permitting is exempt from NEPA because the SDWA's requirements to consider the environment are "functional equivalents" of the impact statement process.[211]

With respect to the level of review that agencies are likely to employ, we believe that federal agencies are likely to conclude that an EIS is required for any possible CCS project like CarbonSAFE in light of the context and intensity of potential impacts. If a less rigorous level of analysis is available, permitting could move forward more expeditiously. A less rigorous approval process, however, may be more difficult to defend in the face of potential legal challenges. This is because, when challenging an EA, a party must show that impacts were either inadequately considered or that impacts exceed the "significance" threshold. By contrast, in legal challenges to EISs, significance of impact is not an issue. Instead, the litigant must demonstrate that the agency

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[207] Schematic from Washington State, Governor's Office of Regulatory Innovation and Assistance https://www.oria.wa.gov/Portals/_oria/VersionedDocuments/Schematics_N-Z/National-Environmental-Policy-Act-Schematics.pdf.

[208] Coalition on Sensible Transportation v. Dole, 826 F.2d 60, 68 (D.C. Cir. 1987) ("Agencies may not evade their responsibilities under NEPA by artificially dividing a major federal action into smaller components, each without 'significant' impact.").

[209] Most Clean Water Act permitting is exempt from NEPA, *see* 33 U.S.C. § 1371(c), as are most Clean Air Act permits, *see* 15 U.S.C. § 793(c)(1).

[210] Under DOE regulations, certain small-scale CO_2 injection wells are categorically exempt from NEPA analysis. 10 C.F.R. § Pt. 1021. Subpt. D App. B § B5.13.

[211] Western Nebraska Resource Council v. EPA, 943 F.2d 867, 871 (8th Cir. 1992).

failed to take the requisite "hard look" at potential impacts.[212] Proceeding as if an EIS is required therefore represents a conservative assumption for a project such as CarbonSAFE.

To expedite the NEPA process and reduce paperwork, federal agencies may integrate the NEPA review with other environmental reviews and consultation processes,[213] incorporate other NEPA documents by reference,[214] or "tiering from statements of broader scope to those of narrower scope, to eliminate repetitive discussions of the same issues."[215] Accordingly, CarbonSafe may be able to utilize the information contained in the Class VI injection well permit application to satisfy much of their NEPA obligation.

A recent review of EISs prepared for large oil and natural gas field development projects in the Intermountain West found that it takes an average of 4.4 years to complete an oil and gas field EIS, as measured from the NOI to ROD (the range was 1,057 to 2,556 days).[216] This represents a rough estimate of the time likely involved in obtaining NEPA approval for the CarbonSAFE Project, as the smaller geographic scope of the CarbonSAFE Project is likely to minimize the level of analysis required. However, as a first-of-kind project associated with a highly scrutinized industry and located proximate to areas that are of great interest to the environmental community, intense public scrutiny should be anticipated.

Notably, on September 1, 2017, the Secretary of the Interior issued an order to all agencies within the Department, including the Bureau of Land Management, directing them to complete their NEPA analyses within a one-year limit. The order also directs agencies to limit their EISs to 150 pages normally, or 300 pages for unusually complicated projects.[217]

Operators should not assume that the Department of the Interior will adhere to either time limits or page restrictions. Accelerating the NEPA process may impact the quality of the analysis and invite litigation. Rushing may, in short, prove to be counterproductive. We anticipate that the BLM will work hard to comply with the Secretarial Order without compromising document defensibility. The best way to do this is to frontload the NEPA analysis by completing requisite studies before publishing a NOI. This will result in delayed initiation of the formal NEPA process.

More importantly, when a federal agency is sued for failing to comply with NEPA's procedural requirements, the reviewing court will still ask whether the agency took the requisite "hard look" at the environmental consequences of the project and a reasonable range of alternatives.[218] This standard of review has not changed. The BLM has a strong incentive to ensure that EISs are defensible in court and is therefore likely to move text from the EIS into an appendix. This practice will change the formatting of NEPA documents but not reduce the overall analysis. The BLM likewise has a similar incentive to delay document completion in order to increase defensibility.

A final consideration involves the potential scope of review that would be required if the CCS operator intends to use only state or private pore space, but where that operator needs to acquire limited surface use rights for pipelines, monitoring wells, or other infrastructure. If such a question arises, the issue becomes the scope of the analysis required pursuant to NEPA. NEPA

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[212] Citizens to Preserve Overton Park, Inc. v. Volpe, 401 U.S. 402 (1971).

[213] 40 C.F.R. § 1500.4(k) (2017).

[214] *Id.* § 1500.4(j).

[215] *Id.* § 1500.4(i).

[216] John Ruple & Mark Capone, *NEPA—Substantive Effectiveness Under a Procedural Mandate: Assessment of Oil and Gas EISs in the Mountain West*, 7 G. WASH. J. ENERGY & ENVTL. L. 39, 43 (2016).

[217] U.S. Dep't of the Interior Secretarial Order 3355 (Sept. 1, 2017).

[218] Citizens to Preserve Overton Park, Inc. v. Volpe, 401 U.S. 402 (1971).

requires analysis of the direct, indirect, and cumulative effects of the various alternatives regardless of whether those impacts occur on federal land. "Direct" environmental effects are those "which are caused by the action and occur at the same time and place."[219] Indirect effects are those "which are caused by the action and are later in time or farther removed in distance, but are still reasonably foreseeable."[220] A cumulative impact is "the impact on the environment which results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions. . . . Cumulative impacts can result from individually minor but collectively significant actions taking place over a period of time."[221] Connected actions cannot be divided into their component parts in order to narrow or expedite the analysis.[222]

While NEPA compliance can be costly and time-consuming, it will likely be a necessary component of CarbonSAFE Rocky Mountain implementation. Possibly the best advice that we can provide regarding NEPA compliance is to coordinate closely with the BLM, be patient, and avoid the temptation to cut corners. A rushed NEPA analysis is more likely to contain errors or omissions that would cause a reviewing court to require a supplemental analysis. Any time saved by streamlining analysis on the front end will likely be more than consumed by litigation and revisions on the back end.[223]

C. The National Historic Preservation Act

Enacted in 1966, the National Historic Preservation Act[224] (NHPA) was intended, in part, to preserve historical and archaeological sites. Section 106 of the NHPA requires that federal agencies complete a review process for all federally funded and permitted projects that will impact sites listed on, or that are eligible for listing on, the National Register of Historic Places.[225] Under section 106, federal agencies must "take into account" the effect a project may have on historic properties. Section 106 allows interested parties an opportunity to comment on the potential impact that projects may have on significant archaeological or historic sites. Like NEPA, the NHPA is a procedural statute that does not require substantive protections. Rather, both statutes require federal agencies to "look before they leap."

Any federal agency whose project, funding, or permit may affect a historic property that is either listed or eligible for inclusion in the National Register of Historic Places must consider project effects and seek to avoid, minimize, or mitigate any adverse effects on historic properties. NHPA compliance will require early consultation with BLM archaeologists and the State Historic Preservation Officer. These individuals will be able to search agency records and identify known cultural and historic sites. Surveys and tribal consultation may be required to determine whether additional cultural or historic sites are found within the project area and, if so, whether these sites are potentially eligible for inclusion on the National Register of Historic Places.

Of note for the CarbonSAFE Rocky Mountain project, oil and natural gas lease sales in the region have been challenged and sometimes deferred because of possible impacts to petroglyphs and pictographs that are known to exist near the San Rafael Swell. These sites, which are almost certainly eligible for inclusion on the National Register of Historic Places, have not been the subject of

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[219] 40 C.F.R. § 1508.8(a).

[220] *Id.* § 1508.8(b).

[221] *Id.* § 1508.7.

[222] *Id.* § 1508.25(a)(1).

[223] *See* John Ruple & Mark Capone, *NEPA, FLPMA, and Impact Reduction: An Empirical Assessment of BLM Resource Management Planning and NEPA in the Mountain West*, 46 ENVTL. L. 952 (2017).

[224] 16 U.S.C. §§ 470 *et seq.*

[225] *Id.* § 470f.

comprehensive surveys and are therefore not well documented. While the project at hand has a limited geographic footprint and is therefore less likely to impact sites across a broad area, the project team should still consult with the BLM and Utah State Historic Preservation Officer to identify archaeological sites, historic mining properties, homesteads, or other sites than may warrant special attention.

D. Lessons Learned from Permitting Other CCS Facilities

We reviewed permitting documents for other CCS facilities in order to identify lessons that could be learned from those experiences, as detailed above. While the CarbonSAFE Rocky Mountain project will be subject to many of the same procedural requirements, factual differences between the project at hand and prior CCS facilities need to be acknowledged when considering the experience at other CCS facilities. Nonetheless, the experience of the other projects is useful when appraising the path forward for a potential CarbonSAFE Rocky Mountain project.

1. NRG Energy (W.A. Parish Post Combustion Project)

NRG Energy's proposed W.A. Parish PCCS Project involved construction of a CO_2 capture facility at NRG's 4,880-acre W.A. Parish Plant in rural Fort Bend County, Texas (sometimes also referred to as the Petra Nova Project). The capture facility would use an amine-based absorption technology to capture at least 90% of the CO_2 from a 250-megawatt equivalent portion of the flue gas exhaust from Unit 8 at the plant. The project would be designed to capture approximately 1.6 million tons of CO_2 per year, and the captured CO_2 would be compressed and transported via a new, 81-mile-long, 12-inch-diameter underground pipeline to the existing West Ranch oil field in Jackson County, Texas. There, the CO_2 would be used for enhanced oil recovery and ultimately sequestered in geologic formations approximately 5,000 to 6,300 feet below the ground surface.

The DOE completed an EIS for the W.A. Parish Project, addressing the following issues: air quality and climate, greenhouse gas emissions, geology, physiography and soils, surface waters, ground water, floodplains, wetlands, biological resources, cultural resources, land use, aesthetics, traffic, transportation, noise, materials and waste management, human health and safety, utilities, community services, socioeconomics, and environmental justice. For purposes of the EIS, the DOE assumed that the project would continue for twenty years. The DOE was required to conduct a NEPA analysis because the project involved DOE funding.

The W.A. Parish Project did not generate significant controversy; there were just four comments on the Draft EIS. Of the four comments received, three came from government agencies, and one was from a member of the general public. Comments from the public focused on air quality impacts associated with the continued combustion of coal and how conversion to a natural gas-fired facility would help reduce both VOC and NOx emissions. The EPA was concerned about damage to navigable waters and jurisdictional wetlands. The DOE asserted that all navigable water would be identified and that any wetland permanently impacted would be mitigated. The FWS was concerned with impacts to listed species under the ESA. The DOE amended the EIS to ensure that more migrating birds would not be impacted during pipeline construction. The Texas Parks and Wildlife Department echoed the FWS and the DOE ensured their concerns were addressed. Pore space ownership was not as issue, as CO_2 was injected into an existing field for EOR.

2. ADM

The ADM project was considered a "federal action" and therefore subject to NEPA because of DOE funding. The NEPA analysis considered only two alternatives, the proposed action and a no action alternative under which the DOE would not contribute any funds. EPA permitting documents do not mention public comments received in response to the ADM proposal. The narrow range of alternatives and absence of a discussion of public comments likely indicate that the project received little public scrutiny. While the reasons for limited public interest are difficult to identify, the setting and short duration of the project were likely contributing factors. Notably, ADM appears to own the pore space into which the CO_2 is injected, thus limiting potential impacts to public lands and removing a major concern that is likely to face the CarbonSAFE project.

As noted in the earlier discussion of SDWA permitting for the ADM project, the EPA did not address pore space ownership as part of its analysis. It also appears that no claim of federal pore space ownership was implicated by the ADM project. CarbonSAFE Rocky Mountain is therefore distinguishable from the ADM permit because the BLM will need to complete a NEPA review before granting rights to utilize the federal surface or sub-surface, and this analysis will necessarily consider pore space ownership. This NEPA analysis will be independent of the EPA's NEPA analysis for the Class VI injection permit. Proximity to the San Rafael Swell is also likely to attract a level of public attention that was absent from the ADM project.

With respect to the ADM project, the EPA also disclaimed any need to consult with the Fish and Wildlife Service regarding impacts to species protected pursuant to the Endangered Species Act. The EPA stated that they found there was no jeopardy to listed species or critical habitat, thus ending the inquiry. Further, EPA disclaimed any need for NEPA review because the action was "administrative in nature." Again, CarbonSAFE should not assume such expedient treatment of its project. While the EPA may consider impacts to wildlife to be beyond the scope of their permitting analysis, the likely use of federal surface or sub-surface for either infrastructure or sequestration will necessitate BLM involvement, and as issuance or a right-of-way or permit to utilize federal lands could represent an irretrievable commitment of resources, the BLM will almost certainly need to consider wildlife impacts before rendering a decision.

V. ADDITIONAL LEGAL AND REGULATORY CONSIDERATIONS

The above analysis highlights the key legal issues that tend to be focused on with respect to CCS projects. However, there are several other issues that may arise, and that would need to be addressed depending on the particular facts of the project. Those facts should come into clearer focus should the CarbonSAFE Rocky Mountain project proceed beyond Phase I.

A. Public Utility Regulation

One key regulatory approval that the CarbonSAFE Rocky Mountain project would have to obtain is a determination that the cost imposed by the project on electricity customers is not too great. This involves six determinations, not one. Rocky Mountain Power is a subsidiary of PacifiCorp. In turn, PacifiCorp allocates portions of is broad generation portfolio among its various utility subsidiaries serving customers in six states: California, Idaho, Oregon, Utah, Washington, and Wyoming. Unless PacifiCorp chose to alter this allocation, conceivably the public service commission in each of those states would need to pass on the cost impacts of the CarbonSAFE project at some point.

At one level, this form of regulation would not appear to pose too high of a burden for the CarbonSAFE project. Although regulatory approval eventually would be needed, utility law generally does not require electricity providers to file a new rate case every time they incur some new cost. Rather, they must only do so when they seek a general rate increase or change.[226] So, the CarbonSAFE project theoretically could be operational before such a rate approval were sought.

[226] *See, e.g.*, UTAH CODE § 54-7-12.

However, two caveats limit how much leeway the proponents of the CarbonSAFE project might actually enjoy. First, public utility commissions typically can start their own investigations of a utility, if they see fit. Thus, if the CarbonSAFE project raised concerns for any of these states' public service commissions, regulatory oversight could arrive more quickly than planned. Second, when a rate case is brought, even by the utility itself, the utility must justify the cost as both "just and reasonable"—that is, not too expensive—as well as "prudent"—that is, an economically efficient investment that a reasonable or prudent manager of the company would make.[227]

Under this substantive standard, the two biggest hurdles to the CarbonSAFE project likely would be economic and policy-based. The economic obstacle is obvious and relates back to the cost barrier to commercial-scale deployment that CCS technology faces. Since the objective of utility regulation is to ensure that companies only incur necessary (and economically efficient) costs in providing service, there is a risk that parties would argue the comparatively high cost of CCS is neither. Of course, were some kind of greenhouse gas emission limit placed on PacifiCorp or Rocky Mountain Power, this might be easier to show, but the receding nature of federal regulation in that context and the absence of it in many state contexts renders that argument more difficult to make. Moreover, even with climate regulation of the electricity sector in place, proponents of the CarbonSAFE project arguably would need to either show that CCS technology is as cost-effective as other ways of mitigating climate emissions (such as solar or wind) or point to a CCS-specific mandate of some kind. This may be difficult.

From a policy-based perspective, the CarbonSAFE project also could face challenges. Many of the states from which PacifiCorp would need regulatory approvals have renewable energy requirements for the electricity sector in place.[228] This could raise questions about why the CarbonSAFE project is appropriate in light of those statutory mandates. Further, two of the states—California and Washington—have climate regulations in place that affect the electricity sector,[229] and one of the states—Oregon—has an outright ban on coal generation beginning in 2030.[230] Again, PacifiCorp potentially could eliminate these concerns by reallocating how it operates its generation fleet, but in the absence of that step, this state-level regulation would appear to create challenges for the CarbonSAFE project, if the electricity generation associated with it is allocated to any of these states. These are concerns for which the project team would want to have a plan before proceeding to implementation of the CarbonSAFE Rocky Mountain project.

B. Brine Disposal

The Navajo sandstone into which the CarbonSAFE Rocky Mountain would inject CO_2 contains saline brine. CO_2 will react with brine to form carbonate, but some brine may be displaced by injected CO_2. The extent to which brine would be displaced was uncertain at the time this report was written. Displacement of brine must be considered as noted in SDWA permitting and tort liability discussions, above. If brine must be extracted to increase storage capacity, extracted brine will need to be dealt with, possibly by using brine for EOR. Use of brine for EOR would trigger the SDWA's UIC class II permitting requirements.

If brine cannot be utilized for EOR, it will need to be disposed of in accordance with applicable environmental laws and regulations. In that case, permits would need to be obtained in

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[227] *See, e.g.*, UTAH CODE § 54-3-1.

[228] *See* CAL. PUB. UTIL. CODE § 399.11; OR. REV. STAT. § 469A.052; UTAH CODE § 10-19-201; WASH. REV. CODE § 19.285.040.

[229] *See, e.g.*, CAL. HEALTH & SAFETY § 38566; Code CAL. PUB. UTIL. § 8341; WASH. REV. CODE § 80.80.040.

[230] *See* OR. REV. STAT. § 757.518.

accordance with the Clean Water Act and other applicable requirements before brine could be discharged into a receiving water or via land application. Any water treatment that results in sludge or contaminated filter materials could trigger hazardous waste disposal permitting requirements.

Alternatively, brine could be disposed of in evaporative ponds, though this could pose additional regulatory challenges, and highly concentrated minerals would require additional processing and disposal. Portions of Eastern Utah suffer from elevated ozone levels, which have been attributed, in part, to oil and gas development activities. Evaporation of oil and gas product water has been identified as a contributor to elevated ozone levels because product water often contains volatile organic compounds (VOCs). VOCs evaporate readily and are subject to atmospheric photochemical reactions that produce ground-level ozone. Any brine that is removed from the storage reservoir may therefore need to be treated to remove VOCs, if VOCs are present in the brine, before evaporation could proceed. Similar concerns could arise if the brine contains trace quantities of radionuclides, or hazardous chemical elements such as arsenic.

Surface disposal could also raise environmental concerns if brine is stored in evaporation ponds that attract wildlife. Hydrocarbons in the brine could coat the wings of migratory birds that are attracted to the water surface. Similarly, salts or other minerals that are toxic to migratory birds can cause avian mortality. Mortality that is attributable to surface disposal operations could trigger liability under the Migratory Bird Treaty Act, the Bald and Gold Eagle Protection Act, the Endangered Species Act, or other state and federal statutes.

Rocky Mountain CarbonSAFE Phase I

Appendix L

CarbonSAFE Class VI Requirement Matrix

DRAFT	EPA Class VI Guidance Document / Sections	CarbonSAFE Phase I Project Plan	Phase I Task	Phase I Subtask	Responsible Person(s)
40 CFR 146.82 - Required Class VI Permit Information					
(a) Prior to the issuance of a permit for the construction of a new Class VI well or the conversion of an existing Class I, Class II, or Class V well to a Class VI well, the owner or operator shall submit, pursuant to §146.91(e), and the Director shall consider the following:					
(1) Information required in §144.31 (e)(1) through (6) of this Section;			2.0	2.1	DEQ/DWQ
144.31 (e) (1) The activities conducted by the applicant which require it to obtain permits under RCRA, UIC, the National Pollution Discharge Elimination System (NPDES) program under the Clean Water Act, or the Prevention of Significant Deterioration (PSD) program under the Clean Air Act.					
144.31 (e) (2) Name, mailing address, and location of the facility for which the application is submitted.					
144.31 (e) (3) Up to four SIC codes which best reflect the principal products or services provided by the facility.					
144.31 (e) (4) The operator's name, address, telephone number, ownership status, and status as Federal, State, private, public, or other entity.					
144.31 (e) (5) Whether the facility is located on Indian lands.					
144.31 (e) (6) A listing of all permits or construction approvals received or applied for under any of the following programs:					
(i) Hazardous Waste Management program under RCRA.					
(ii) UIC program under SDWA.					
(iii) NPDES program under CWA.					
(iv) Prevention of Significant Deterioration (PSD) program under the Clean Air Act.					
(v) Nonattainment program under the Clean Air Act.					
(vi) National Emission Standards for Hazardous Pollutants (NESHAPS) preconstruction approval under the Clean Air Act.					

DRAFT	EPA Class VI Guidance Document / Sections	CarbonSAFE Phase I Project Plan	Phase I Task	Phase I Subtask	Responsible Person(s)
(vii) Ocean dumping permits under the Marine Protection Research and Sanctuaries Act.					
(viii) Dredge and fill permits under section 404 of CWA					
(ix) Other relevant environmental permits, including State permits.					
(2) A map showing the injection well for which a permit is sought and the applicable area of review consistent with § 146.84. Within the area of review, the map must show the number or name, and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, State- or EPA-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features including structures intended for human occupancy, State, Tribal, and Territory boundaries, and roads. The map should also show faults, if known or suspected. Only information of public record is required to be included on this map;	Site Characterization / Sect. 2.2	CarbonSAFE Site Pre-Feasibility Plan	3.0	3.1, 3.2, 3.3, 3.4	UGS - Morgan; UU - Chan
(3) Information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, including:		CarbonSAFE Site Pre-Feasibility Plan	3.0	3.1, 3.2, 3.3	UGS - Morgan; UU - Chan
(i) Maps and cross sections of the area of review;	Site Characterization / Sect. 2.3.1			3.1, 3.2	
(ii) The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not interfere with containment;	Site Characterization / Sect. 2.3.2				
(iii) Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;	Site Characterization / Sect. 2.3.3, 3.1, 2.3.4, 2.3.5, 2.3.10				
(iv) Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s);	Site Characterization / Sect. 2.3.6				

DRAFT	EPA Class VI Guidance Document / Sections	CarbonSAFE Phase I Project Plan	Phase I Task	Phase I Subtask	Responsible Person(s)
(v) Information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment; and	Site Characterization / Sect. 2.3.7				
(vi) Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area.	Site Characterization / Sect. 2.1				
(4) A tabulation of all wells within the area of review which penetrate the injection or confining zone(s). Such data must include a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require;	AoR & CA / Sect. 4	CarbonSAFE Site Pre-Feasibility Plan			
(5) Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their positions relative to the injection zone(s), and the direction of water movement, where known;	Site Characterization / Sect. 2.3.8	CarbonSAFE Site Pre-Feasibility Plan			
(6) Baseline geochemical data on subsurface formations, including all USDWs in the area of review;	Site Characterization / Sect. 2.3.9	CarbonSAFE Site Pre-Feasibility Plan			
(7) Proposed operating data for the proposed geologic sequestration site:		Task 4.0 Plan	4.0, 3.0		UU: Miland Deo / PacifiCorp
(i) Average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the carbon dioxide stream;					
(ii) Average and maximum injection pressure;					
(iii) The source(s) of the carbon dioxide stream; and					
(iv) An analysis of the chemical and physical characteristics of the carbon dioxide stream.				4.1	
(8) Proposed pre-operational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone(s) and confining zone(s) and that meets the requirements at § 146.87;		Not Phase I			
(9) Proposed stimulation program, a description of stimulation fluids to be used and a determination that stimulation will not interfere with containment;		Not Phase I			

DRAFT	EPA Class VI Guidance Document / Sections	CarbonSAFE Phase I Project Plan	Phase I Task	Phase I Subtask	Responsible Person(s)
(10) Proposed procedure to outline steps necessary to conduct injection operation;		Not Phase I			
(11) Schematics or other appropriate drawings of the surface and subsurface construction details of the well;		Not Phase I			
(12) Injection well construction procedures that meet the requirements of § 146.86;		Not Phase I			
(13) Proposed area of review and corrective action plan that meets the requirements under § 146.84;	AoR & CAP / All Sections	AoR & CAP			
(14) A demonstration, satisfactory to the Director, that the applicant has met the financial responsibility requirements under § 146.85;		Not Phase I; Economic Assess.			
(15) Proposed testing and monitoring plan required by § 146.90;		Not Phase I; Economic Assess.			
(16) Proposed injection well plugging plan required by § 146.92(b);		Not Phase I; Economic Assess.			
(17) Proposed post-injection site care and site closure plan required by § 146.93(a);		Not Phase I; Economic Assess.			
(18) At the Director's discretion, a demonstration of an alternative post-injection site care timeframe required by § 146.93(c);		Not Phase I; Economic Assess.			
(19) Proposed emergency and remedial response plan required by § 146.94(a);		Not Phase I			
(20) A list of contacts, submitted to the Director, for those States, Tribes, and Territories identified to be within the area of review of the Class VI project based on information provided in paragraph (a)(2) of this section; and		Not Phase I, Public Outreach			
(21) Any other information requested by the Director.					
(b) The Director shall notify, in writing, any States, Tribes, or Territories within the area of review of the Class VI project based on information provided in paragraphs (a)(2) and (a)(20) of this section of the permit application and pursuant to the requirements at § 145.23(f)(13) of this chapter.		EPA Responsibility			
(c) Prior to granting approval for the operation of a Class VI well, the Director shall consider the following information:		Not Phase I			

DRAFT	EPA Class VI Guidance Document / Sections	CarbonSAFE Phase I Project Plan	Phase I Task	Phase I Subtask	Responsible Person(s)
(1) The final area of review based on modeling, using data obtained during logging and testing of the well and the formation as required by paragraphs (c)(2), (3), (4), (6), (7), and (10) of this section;		Not Phase I			
(2) Any relevant updates, based on data obtained during logging and testing of the well and the formation as required by paragraphs (c)(3), (4), (6), (7), and (10) of this section, to the information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, submitted to satisfy the requirements of paragraph (a)(3) of this section;	Site Characterization / Sect. 4	Not Phase I			
(3) Information on the compatibility of the carbon dioxide stream with fluids in the injection zone(s) and minerals in both the injection and the confining zone(s), based on the results of the formation testing program, and with the materials used to construct the well;	Site Characterization / Sect. 3.3		3.0	3.1	UU: Chan; UGS: Morgan
(4) The results of the formation testing program required at paragraph (a)(8) of this section;	Site Characterization / Sect. 4.1	Not Phase I			
(5) Final injection well construction procedures that meet the requirements of § 146.86;		Not Phase I			
(6) The status of corrective action on wells in the area of review;		Not Phase I			
(7) All available logging and testing program data on the well required by § 146.87;	Site Characterization / Sect. 4.2, 4.3, 4.4, 4.5	Not Phase I			
(8) A demonstration of mechanical integrity pursuant to § 146.89;		Not Phase I			

DRAFT	EPA Class VI Guidance Document / Sections	CarbonSAFE Phase I Project Plan	Phase I Task	Phase I Subtask	Responsible Person(s)
(9) Any updates to the proposed area of review and corrective action plan, testing and monitoring plan, injection well plugging plan, post-injection site care and site closure plan, or the emergency and remedial response plan submitted under paragraph (a) of this section, which are necessary to address new information collected during logging and testing of the well and the formation as required by all paragraphs of this section, and any updates to the alternative post-injection site care timeframe demonstration submitted under paragraph (a) of this section, which are necessary to address new information collected during the logging and testing of the well and the formation as required by all paragraphs of this section; and		Not Phase I			
(10) Any other information requested by the Director.					
(d) Owners or operators seeking a waiver of the requirement to inject below the lowermost USDW must also refer to § 146.95 and submit a supplemental report, as required at § 146.95(a). The supplemental report is not part of the permit application.			3.0	3.1	
40 CFR § 146.83 - Minimum criteria for siting. NOTICE: Section 3 of the Site Characterization Guidance entitled 'Data Synthesis for Demonstration of Site Suitability' contains more detail than indicated below.	Site Characterization		3.0	3.1 3.2 3.3 3.4	UU: Chan; UGS: Morgan
(a) Owners or operators of Class VI wells must demonstrate to the satisfaction of the Director that the wells will be sited in areas with a suitable geologic system. The owners or operators must demonstrate that the geologic system comprises:	Site Characterization		3.0	3.1 3.2	
(1) An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream;	Site Characterization		3.0	3.1 3.2	

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(2) Confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).	Site Characterization		3.0	3.1 3.2	
(b) The Director may require owners or operators of Class VI wells to identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.	Site Characterization		3.0	3.1 3.2	
40 CFR § 146.84 - Area of review and corrective action.	AoR Evaluation & Corrective Action (AoR & CA)				
(a) The area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.	AoR & CA				
(b) The owner or operator of a Class VI well must prepare, maintain, and comply with a plan to delineate the area of review for a proposed geologic sequestration project, periodically reevaluate the delineation, and perform corrective action that meets the requirements of this section and is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. As a part of the permit application for approval by the Director, the owner or operator must submit an area of review and corrective action plan that includes the following information:	AoR & CA	AoR & CA Plan			

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(1) The method for delineating the area of review that meets the requirements of paragraph (c) of this section, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	AoR & CA / Sect. 2 & 3		3.0	3.2	
(2) A description of:					
(i) The minimum fixed frequency, not to exceed five years, at which the owner or operator proposes to reevaluate the area of review;	AoR & CA / Sect. 5	Not Phase I			
(ii) The monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation as determined by the minimum fixed frequency established in paragraph (b)(2)(i) of this section.	AoR & CA / Sect. 5	Not Phase I			
(iii) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and	AoR & CA / Sect. 5	Not Phase I			
(iv) How corrective action will be conducted to meet the requirements of paragraph (d) of this section, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.	AoR & CA / Sect. 5	Not Phase I			
(c) Owners or operators of Class VI wells must perform the following actions to delineate the area of review and identify all wells that require corrective action:			3.0		
(1) Predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the Director. The model must:	AoR & CA / Sect. 2 & 3		3.0	3.1, 3.2	

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(i) Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s) and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project;	AoR & CA / Sect. 2 & 3		3.0	3.1	
(ii) Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	AoR & CA / Sect. 2 & 3		3.0	3.1	
(iii) Consider potential migration through faults, fractures, and artificial penetrations.	AoR & CA / Sect. 2 & 3		3.0	3.1	
(2) Using methods approved by the Director, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone(s). Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require; and	AoR & CA / Sect. 4.2		3.0		
(3) Determine which abandoned wells in the area of review have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs, including use of materials compatible with the carbon dioxide stream.	AoR & CA / Sect. 4.3				
(d) Owners or operators of Class VI wells must perform corrective action on all wells in the area of review that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate.	AoR & CA / Sect. 4.4	Not Phase I			
(e) At the minimum fixed frequency, not to exceed five years, as specified in the area of review and corrective action plan, or when monitoring and operational conditions warrant, owners or operators must:	AoR & CA / Sect. 5	Not Phase I			
(1) Reevaluate the area of review in the same manner specified in paragraph (c)(1) of this section;					
(2) Identify all wells in the reevaluated area of review that require corrective action in the same manner specified in paragraph (c) of this section;					

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(3) Perform corrective action on wells requiring corrective action in the reevaluated area of review in the same manner specified in paragraph (d) of this section; and					
(4) Submit an amended area of review and corrective action plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the area of review and corrective action plan is needed. Any amendments to the area of review and corrective action plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate.					
(f) The emergency and remedial response plan (as required by § 146.94) and the demonstration of financial responsibility (as described by § 146.85) must account for the area of review delineated as specified in paragraph (c)(1) of this section or the most recently evaluated area of review delineated under paragraph (e) of this section, regardless of whether or not corrective action in the area of review is phased.		Not Phase I			
(g) All modeling inputs and data used to support area of review reevaluations under paragraph (e) of this section shall be retained for 10 years.					
40 CFR § 146.85 - Financial responsibility.	Financial Responsibility (FR)		2.0	2.2	UU: Ruple, Davies
(a) The owner or operator must demonstrate and maintain financial responsibility as determined by the Director that meets the following conditions:					
(1) The financial responsibility instrument(s) used must be from the following list of qualifying instruments:	FR / Sect. 3 A				
(i) Trust Funds.					
(ii) Surety Bonds.					
(iii) Letter of Credit.					
(iv) Insurance.					

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(v) Self Insurance (i.e., Financial Test and Corporate Guarantee).					
(vi) Escrow Account.					
(vii) Any other instrument(s) satisfactory to the Director.	FR / Sect. 3 B				
(2) The qualifying instrument(s) must be sufficient to cover the cost of:	FR / Sect. 4				
(i) Corrective action (that meets the requirements of § 146.84);					
(ii) Injection well plugging (that meets the requirements of § 146.92);					
(iii) Post injection site care and site closure (that meets the requirements of § 146.93); and					
(iv) Emergency and remedial response (that meets the requirements of § 146.94).					
(3) The financial responsibility instrument(s) must be sufficient to address endangerment of underground sources of drinking water.	FR / Sect. 6				
(4) The qualifying financial responsibility instrument(s) must comprise protective conditions of coverage.	FR / Sect. 5				
(i) Protective conditions of coverage must include at a minimum cancellation, renewal, and continuation provisions, specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew with a new qualifying financial instrument, and requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.					

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(A) Cancellation—for purposes of this part, an owner or operator must provide that their financial mechanism may not cancel, terminate or fail to renew except for failure to pay such financial instrument. If there is a failure to pay the financial instrument, the financial institution may elect to cancel, terminate, or fail to renew the instrument by sending notice by certified mail to the owner or operator and the Director. The cancellation must not be final for 120 days after receipt of cancellation notice. The owner or operator must provide an alternate financial responsibility demonstration within 60 days of notice of cancellation, and if an alternate financial responsibility demonstration is not acceptable (or possible), any funds from the instrument being cancelled must be released within 60 days of notification by the Director.					
(B) Renewal—for purposes of this part, owners or operators must renew all financial instruments, if an instrument expires, for the entire term of the geologic sequestration project. The instrument may be automatically renewed as long as the owner or operator has the option of renewal at the face amount of the expiring instrument. The automatic renewal of the instrument must, at a minimum, provide the holder with the option of renewal at the face amount of the expiring financial instrument.					
(C) Cancellation, termination, or failure to renew may not occur and the financial instrument will remain in full force and effect in the event that on or before the date of expiration: The Director deems the facility abandoned; or the permit is terminated or revoked or a new permit is denied; or closure is ordered by the Director or a U.S. district court or other court of competent jurisdiction; or the owner or operator is named as debtor in a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code; or the amount due is paid.					
(5) The qualifying financial responsibility instrument(s) must be approved by the Director.	FR / Sect. 7				

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(i) The Director shall consider and approve the financial responsibility demonstration for all the phases of the geologic sequestration project prior to issue a Class VI permit (§ 146.82).					
(ii) The owner or operator must provide any updated information related to their financial responsibility instrument(s) on an annual basis and if there are any changes, the Director must evaluate, within a reasonable time, the financial responsibility demonstration to confirm that the instrument(s) used remain adequate for use. The owner or operator must maintain financial responsibility requirements regardless of the status of the Director's review of the financial responsibility demonstration.					
(iii) The Director may disapprove the use of a financial instrument if he determines that it is not sufficient to meet the requirements of this section.					
(6) The owner or operator may demonstrate financial responsibility by using one or multiple qualifying financial instruments for specific phases of the geologic sequestration project.	FR / Sect. 5 H				
(i) In the event that the owner or operator combines more than one instrument for a specific geologic sequestration phase (e.g., well plugging), such combination must be limited to instruments that are not based on financial strength or performance (i.e., self insurance or performance bond), for example trust funds, surety bonds guaranteeing payment into a trust fund, letters of credit, escrow account, and insurance. In this case, it is the combination of mechanisms, rather than the single mechanism, which must provide financial responsibility for an amount at least equal to the current cost estimate.					
(ii) When using a third-party instrument to demonstrate financial responsibility, the owner or operator must provide a proof that the third-party providers either have passed financial strength requirements based on credit ratings; or has met a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.					

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(iii) An owner or operator using certain types of third-party instruments must establish a standby trust to enable EPA to be party to the financial responsibility agreement without EPA being the beneficiary of any funds. The standby trust fund must be used along with other financial responsibility instruments (e.g., surety bonds, letters of credit, or escrow accounts) to provide a location to place funds if needed.					
(iv) An owner or operator may deposit money to an escrow account to cover financial responsibility requirements; this account must segregate funds sufficient to cover estimated costs for Class VI (geologic sequestration) financial responsibility from other accounts and uses.					
(v) An owner or operator or its guarantor may use self insurance to demonstrate financial responsibility for geologic sequestration projects. In order to satisfy this requirement the owner or operator must meet a Tangible Net Worth of an amount approved by the Director, have a Net working capital and tangible net worth each at least six times the sum of the current well plugging, post injection site care and site closure cost, have assets located in the United States amounting to at least 90 percent of total assets or at least six times the sum of the current well plugging, post injection site care and site closure cost, and must submit a report of its bond rating and financial information annually. In addition the owner or operator must either: Have a bond rating test of AAA, AA, A, or BBB as issued by Standard & Poor's or Aaa, Aa, A, or Baa as issued by Moody's; or meet all of the following five financial ratio thresholds: A ratio of total liabilities to net worth less than 2.0; a ratio of current assets to current liabilities greater than 1.5; a ratio of the sum of net income plus depreciation, depletion, and amortization to total liabilities greater than 0.1; A ratio of current assets minus current liabilities to total assets greater than -0.1; and a net profit (revenues minus expenses) greater than 0.					

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(vi) An owner or operator who is not able to meet corporate financial test criteria may arrange a corporate guarantee by demonstrating that its corporate parent meets the financial test requirements on its behalf. The parent's demonstration that it meets the financial test requirement is insufficient if it has not also guaranteed to fulfill the obligations for the owner or operator.					
(vii) An owner or operator may obtain an insurance policy to cover the estimated costs of geologic sequestration activities requiring financial responsibility. This insurance policy must be obtained from a third party provider.					
(b) The requirement to maintain adequate financial responsibility and resources is directly enforceable regardless of whether the requirement is a condition of the permit.					
(1) The owner or operator must maintain financial responsibility and resources until:					
(i) The Director receives and approves the completed post-injection site care and site closure plan; and					
(ii) The Director approves site closure.					
(2) The owner or operator may be released from a financial instrument in the following circumstances:					
(i) The owner or operator has completed the phase of the geologic sequestration project for which the financial instrument was required and has fulfilled all its financial obligations as determined by the Director, including obtaining financial responsibility for the next phase of the GS project, if required; or					
(ii) The owner or operator has submitted a replacement financial instrument and received written approval from the Director accepting the new financial instrument and releasing the owner or operator from the previous financial instrument.					
(c) The owner or operator must have a detailed written estimate, in current dollars, of the cost of performing corrective action on wells in the area of review, plugging the injection well(s), post-injection site care and site closure, and emergency and remedial response.					

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(1) The cost estimate must be performed for each phase separately and must be based on the costs to the regulatory agency of hiring a third party to perform the required activities. A third party is a party who is not within the corporate structure of the owner or operator.					
(2) During the active life of the geologic sequestration project, the owner or operator must adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instrument(s) used to comply with paragraph (a) of this section and provide this adjustment to the Director. The owner or operator must also provide to the Director written updates of adjustments to the cost estimate within 60 days of any amendments to the area of review and corrective action plan (§ 146.84), the injection well plugging plan (§ 146.92), the post-injection site care and site closure plan (§ 146.93), and the emergency and remedial response plan (§ 146.94).					
(3) The Director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic sequestration project, the owner or operator must revise the cost estimate no later than 60 days after the Director has approved the request to modify the area of review and corrective action plan (§ 146.84), the injection well plugging plan (§ 146.92), the post-injection site care and site closure plan (§ 146.93), and the emergency and response plan (§ 146.94), if the change in the plan increases the cost. If the change to the plans decreases the cost, any withdrawal of funds must be approved by the Director. Any decrease to the value of the financial assurance instrument must first be approved by the Director. The revised cost estimate must be adjusted for inflation as specified at paragraph (c)(2) of this section.					

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(4) Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the owner or operator, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the Director, or obtain other financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the owner or operator has received written approval from the Director.					
(d) The owner or operator must notify the Director by certified mail of adverse financial conditions such as bankruptcy that may affect the ability to carry out injection well plugging and post-injection site care and site closure.					
(1) In the event that the owner or operator or the third party provider of a financial responsibility instrument is going through a bankruptcy, the owner or operator must notify the Director by certified mail of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the owner or operator as debtor, within 10 days after commencement of the proceeding.					
(2) A guarantor of a corporate guarantee must make such a notification to the Director if he/she is named as debtor, as required under the terms of the corporate guarantee.					
(3) An owner or operator who fulfills the requirements of paragraph (a) of this section by obtaining a trust fund, surety bond, letter of credit, escrow account, or insurance policy will be deemed to be without the required financial assurance in the event of bankruptcy of the trustee or issuing institution, or a suspension or revocation of the authority of the trustee institution to act as trustee of the institution issuing the trust fund, surety bond, letter of credit, escrow account, or insurance policy. The owner or operator must establish other financial assurance within 60 days after such an event.					

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(e) The owner or operator must provide an adjustment of the cost estimate to the Director within 60 days of notification by the Director, if the Director determines during the annual evaluation of the qualifying financial responsibility instrument(s) that the most recent demonstration is no longer adequate to cover the cost of corrective action (as required by § 146.84), injection well plugging (as required by § 146.92), post-injection site care and site closure (as required by § 146.93), and emergency and remedial response (as required by § 146.94).					
(f) The Director must approve the use and length of pay-in-periods for trust funds or escrow accounts.					
40 CFR § 146.86 - Injection well construction requirements.	Well Construction / Sect. 2	Not Phase I			
(a) General. The owner or operator must ensure that all Class VI wells are constructed and completed to:					
(1) Prevent the movement of fluids into or between USDWs or into any unauthorized zones;	Well Construction / Sect. 2.1				
(2) Permit the use of appropriate testing devices and workover tools; and	Well Construction / Sect. 2.2				
(3) Permit continuous monitoring of the annulus space between the injection tubing and long string casing.	Well Construction / Sect. 2.2.2				
(b) Casing and cementing of Class VI wells.	Well Construction / Sect. 2.4, 2.5				

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(1) Casing and cement or other materials used in the construction of each Class VI well must have sufficient structural strength and be designed for the life of the geologic sequestration project. All well materials must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The casing and cementing program must be designed to prevent the movement of fluids into or between USDWs. In order to allow the Director to determine and specify casing and cementing requirements, the owner or operator must provide the following information:	Well Construction / Sect. 2.4.1				
(i) Depth to the injection zone(s);					
(ii) Injection pressure, external pressure, internal pressure, and axial loading;					
(iii) Hole size;					
(iv) Size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material);					
(v) Corrosiveness of the carbon dioxide stream and formation fluids;					
(vi) Down-hole temperatures;					
(vii) Lithology of injection and confining zone(s);					
(viii) Type or grade of cement and cement additives; and					
(ix) Quantity, chemical composition, and temperature of the carbon dioxide stream.					
(2) Surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of a single or multiple strings of casing and cement.	Well Construction / Sect. 2.5				
(3) At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages.	Well Construction / Sect. 2.5				

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(4) Circulation of cement may be accomplished by staging. The Director may approve an alternative method of cementing in cases where the cement cannot be recirculated to the surface, provided the owner or operator can demonstrate by using logs that the cement does not allow fluid movement behind the well bore.	Well Construction / Sect. 2.5				
(5) Cement and cement additives must be compatible with the carbon dioxide stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project. The integrity and location of the cement shall be verified using technology capable of evaluating cement quality radially and identifying the location of channels to ensure that USDWs are not endangered.	Well Construction / Sect. 2.5.3				
(c) Tubing and packer.					
(1) Tubing and packer materials used in the construction of each Class VI well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director.	Well Construction / Sect. 2.6				
(2) All owners or operators of Class VI wells must inject fluids through tubing with a packer set at a depth opposite a cemented interval at the location approved by the Director.	Well Construction / Sect. 2.6				
(3) In order for the Director to determine and specify requirements for tubing and packer, the owner or operator must submit the following information:	Well Construction / Sect. 2.7				
(i) Depth of setting;					
(ii) Characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids;					
(iii) Maximum proposed injection pressure;					
(iv) Maximum proposed annular pressure;					
(v) Proposed injection rate (intermittent or continuous) and volume and/or mass of the carbon dioxide stream;					

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(vi) Size of tubing and casing; and					
(vii) Tubing tensile, burst, and collapse strengths.					
40 CFR § 146.87 - Logging, sampling, and testing prior to injection well operation.					
(a) During the drilling and construction of a Class VI injection well, the owner or operator must run appropriate logs, surveys and tests to determine or verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in all relevant geologic formations to ensure conformance with the injection well construction requirements under § 146.86 and to establish accurate baseline data against which future measurements may be compared. The owner or operator must submit to the Director a descriptive report prepared by a knowledgeable log analyst that includes an interpretation of the results of such logs and tests. At a minimum, such logs and tests must include:					
(1) Deviation checks during drilling on all holes constructed by drilling a pilot hole which is enlarged by reaming or another method. Such checks must be at sufficiently frequent intervals to determine the location of the borehole and to ensure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling; and	Well Construction / Sect. 2.2.3				
(2) Before and upon installation of the surface casing:					
(i) Resistivity, spontaneous potential, and caliper logs before the casing is installed; and	Well Construction / Sect. 2.2.4				
(ii) A cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented.	Well Construction / Sect. 2.5.4				
(3) Before and upon installation of the long string casing:					
(i) Resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder logs, and any other logs the Director requires for the given geology before the casing is installed; and					

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(ii) A cement bond and variable density log, and a temperature log after the casing is set and cemented.					
(4) A series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which may include:	Testing & Monitoring Sect. 2, 2.2, 2.3.4				
(i) A pressure test with liquid or gas;					
(ii) A tracer survey such as oxygen-activation logging;					
(iii) A temperature or noise log;					
(iv) A casing inspection log; and					
(5) Any alternative methods that provide equivalent or better information and that are required by and/or approved of by the Director.	Testing & Monitoring Sect. 2, 2.2, 2.3.4				
(b) The owner or operator must take whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone(s), and must submit to the Director a detailed report prepared by a log analyst that includes: Well log analyses (including well logs), core analyses, and formation fluid sample information. The Director may accept information on cores from nearby wells if the owner or operator can demonstrate that core retrieval is not possible and that such cores are representative of conditions at the well. The Director may require the owner or operator to core other formations in the borehole.			3.0	3.1	UGS: Morgan
(c) The owner or operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s).					
(d) At a minimum, the owner or operator must determine or calculate the following information concerning the injection and confining zone(s):					
(1) Fracture pressure;	Site Characterization / Sect. 4.4				
(2) Other physical and chemical characteristics of the injection and confining zone(s); and					
(3) Physical and chemical characteristics of the formation fluids in the injection zone(s).					

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(e) Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):					
(1) A pressure fall-off test; and,					
(2) A pump test; or					
(3) Injectivity tests.					
(f) The owner or operator must provide the Director with the opportunity to witness all logging and testing by this subpart. The owner or operator must submit a schedule of such activities to the Director 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test.					
40 CFR § 146.88 - Injection well operating requirements.	Well Construction / Sect. 4				
(a) Except during stimulation, the owner or operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW. Pursuant to requirements at § 146.82(a)(9), all stimulation programs must be approved by the Director as part of the permit application and incorporated into the permit.	Well Construction / Sect. 4.1				
(b) Injection between the outermost casing protecting USDWs and the well bore is prohibited.	Well Construction / Sect. 4.1				
(c) The owner or operator must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director. The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.	Well Construction / Sect. 4.2				

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(d) Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the owner or operator must maintain mechanical integrity of the injection well at all times.					
(e) The owner or operator must install and use:					
(1) Continuous recording devices to monitor: The injection pressure; the rate, volume and/or mass, and temperature of the carbon dioxide stream; and the pressure on the annulus between the tubing and the long string casing and annulus fluid volume; and	Testing & Monitoring Sect. 3.2, 3.3				
(2) Alarms and automatic surface shut-off systems or, at the discretion of the Director, down-hole shut-off systems (e.g., automatic shut-off, check valves) for onshore wells or, other mechanical devices that provide equivalent protection; and					
(3) Alarms and automatic down-hole shut-off systems for wells located offshore but within State territorial waters, designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate, or other parameters diverge beyond permitted ranges and/or gradients specified in the permit.					
(f) If a shutdown (i.e., down-hole or at the surface) is triggered or a loss of mechanical integrity is discovered, the owner or operator must immediately investigate and identify as expeditiously as possible the cause of the shutoff. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required under paragraph (e) of this section otherwise indicates that the well may be lacking mechanical integrity, the owner or operator must:					
(1) Immediately cease injection;					
(2) Take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone;					
(3) Notify the Director within 24 hours;					

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(4) Restore and demonstrate mechanical integrity to the satisfaction of the Director prior to resuming injection; and					
(5) Notify the Director when injection can be expected to resume.					
40 CFR § 146.89 - Mechanical integrity.	Testing & Monitoring				
(a) A Class VI well has mechanical integrity if:					
(1) There is no significant leak in the casing, tubing, or packer; and	Testing & Monitoring Sect. 2.2				
(2) There is no significant fluid movement into a USDW through channels adjacent to the injection well bore.	Testing & Monitoring Sect. 2.3				
(b) To evaluate the absence of significant leaks under paragraph (a)(1) of this section, owners or operators must, following an initial annulus pressure test, continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in § 146.88 (e);	Testing & Monitoring Sect. 2.1				
(c) At least once per year, the owner or operator must use one of the following methods to determine the absence of significant fluid movement under paragraph (a)(2) of this section:	Testing & Monitoring Sect. 2.3				
(1) An approved tracer survey such as an oxygen-activation log; or					
(2) A temperature or noise log.					
(d) If required by the Director, at a frequency specified in the testing and monitoring plan required at § 146.90, the owner or operator must run a casing inspection log to determine the presence or absence of corrosion in the long-string casing.	Testing & Monitoring Sect. 3.4				

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(e) The Director may require any other test to evaluate mechanical integrity under paragraphs (a)(1) or (a)(2) of this section. Also, the Director may allow the use of a test to demonstrate mechanical integrity other than those listed above with the written approval of the Administrator. To obtain approval for a new mechanical integrity test, the Director must submit a written request to the Administrator setting forth the proposed test and all technical data supporting its use. The Administrator may approve the request if he or she determines that it will reliably demonstrate the mechanical integrity of wells for which its use is proposed. Any alternate method approved by the Administrator will be published in the Federal Register and may be used in all States in accordance with applicable State law unless its use is restricted at the time of approval by the Administrator.	Testing & Monitoring Sect. 2.1				
(f) In conducting and evaluating the tests enumerated in this section or others to be allowed by the Director, the owner or operator and the Director must apply methods and standards generally accepted in the industry. When the owner or operator reports the results of mechanical integrity tests to the Director, he/she shall include a description of the test(s) and the method(s) used. In making his/her evaluation, the Director must review monitoring and other test data submitted since the previous evaluation.					
(g) The Director may require additional or alternative tests if the results presented by the owner or operator under paragraphs (a) through (d) of this section are not satisfactory to the Director to demonstrate that there is no significant leak in the casing, tubing, or packer, or to demonstrate that there is no significant movement of fluid into a USDW resulting from the injection activity as stated in paragraphs (a)(1) and (2) of this section.	Testing & Monitoring Sect. 2.2, 2.3.4				
40 CFR § 146.90 - Testing and monitoring requirements.	Testing & Monitoring				

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The owner or operator of a Class VI well must prepare, maintain, and comply with a testing and monitoring plan to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The testing and monitoring plan must be submitted with the permit application, for Director approval, and must include a description of how the owner or operator will meet the requirements of this section, including accessing sites for all necessary monitoring and testing during the life of the project. Testing and monitoring associated with geologic sequestration projects must, at a minimum, include:	Testing & Monitoring Sect. 1.2				
(a) Analysis of the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics;	Testing & Monitoring Sect. 3.1				
(b) Installation and use, except during well workovers as defined in § 146.88(d), of continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; and the annulus fluid volume added;	Testing & Monitoring Sect. 3.2, 3.3				
(c) Corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion, which must be performed on a quarterly basis to ensure that the well components meet the minimum standards for material strength and performance set forth in § 146.86(b), by:	Testing & Monitoring Sect. 3.4				
(1) Analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or					
(2) Routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or					
(3) Using an alternative method approved by the Director;					
(d) Periodic monitoring of the ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones including:	Testing & Monitoring Sect. 4				

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(1) The location and number of monitoring wells based on specific information about the geologic sequestration project, including injection rate and volume, geology, the presence of artificial penetrations, and other factors; and					
(2) The monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data that has been collected under § 146.82(a)(6) and on any modeling results in the area of review evaluation required by § 146.84(c).					
(e) A demonstration of external mechanical integrity pursuant to § 146.89(c) at least once per year until the injection well is plugged; and, if required by the Director, a casing inspection log pursuant to requirements at § 146.89(d) at a frequency established in the testing and monitoring plan;	Testing & Monitoring Sect. 2.3				
(f) A pressure fall-off test at least once every five years unless more frequent testing is required by the Director based on site-specific information;	Testing & Monitoring Sect. 3.5				
(g) Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) by using:	Testing & Monitoring Sect. 5				
(1) Direct methods in the injection zone(s); and,	Testing & Monitoring Sect. 5.2				
(2) Indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the Director determines, based on site-specific geology, that such methods are not appropriate;	Testing & Monitoring Sect. 5.3				
(h) The Director may require surface air monitoring and/or soil gas monitoring to detect movement of carbon dioxide that could endanger a USDW.	Testing & Monitoring Sect. 6				
(1) Design of Class VI surface air and/or soil gas monitoring must be based on potential risks to USDWs within the area of review;					
(2) The monitoring frequency and spatial distribution of surface air monitoring and/or soil gas monitoring must be decided using baseline data, and the monitoring plan must describe how the proposed monitoring will yield useful information on the area of review delineation and/or compliance with standards under § 144.12 of this chapter;					

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(3) If an owner or operator demonstrates that monitoring employed under §§ 98.440 to 98.449 of this chapter (Clean Air Act, 42 U.S.C. 7401 et seq.) accomplishes the goals of paragraphs (h)(1) and (2) of this section, and meets the requirements pursuant to § 146.91(c)(5), a Director that requires surface air/soil gas monitoring must approve the use of monitoring employed under §§ 98.440 to 98.449 of this chapter. Compliance with §§ 98.440 to 98.449 of this chapter pursuant to this provision is considered a condition of the Class VI permit;					
(i) Any additional monitoring, as required by the Director, necessary to support, upgrade, and improve computational modeling of the area of review evaluation required under § 146.84(c) and to determine compliance with standards under § 144.12 of this chapter;					
(j) The owner or operator shall periodically review the testing and monitoring plan to incorporate monitoring data collected under this subpart, operational data collected under § 146.88, and the most recent area of review reevaluation performed under § 146.84(e). In no case shall the owner or operator review the testing and monitoring plan less often than once every five years. Based on this review, the owner or operator shall submit an amended testing and monitoring plan or demonstrate to the Director that no amendment to the testing and monitoring plan is needed. Any amendments to the testing and monitoring plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate. Amended plans or demonstrations shall be submitted to the Director as follows:					
(1) Within one year of an area of review reevaluation;					
(2) Following any significant changes to the facility, such as addition of monitoring wells or newly permitted injection wells within the area of review, on a schedule determined by the Director; or					
(3) When required by the Director.					
(k) A quality assurance and surveillance plan for all testing and monitoring requirements.					

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40 CFR § 146.91 - Reporting requirements. NOTICE: There are additional reporting requirements pertaining to the development of CCS Project Plans that are not detailed below. READ THE RECORDKEEPING, REPORTING & DATA MANAGEMENT GUIDANCE.	Recordkeeping, Reporting & Data Management (R R & DM)				
The owner or operator must, at a minimum, provide, as specified in paragraph (e) of this section, the following reports to the Director, for each permitted Class VI well:					
(a) Semi-annual reports containing:	RR & DM / Sect. 5.1				
(1) Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;	RR & DM / Sect. 5.1.1				
(2) Monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure;	RR & DM / Sect. 5.1.2				
(3) A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;	RR & DM / Sect. 5.1.3				
(4) A description of any event which triggers a shut-off device required pursuant to § 146.88(e) and the response taken;	RR & DM / Sect. 5.1.3				
(5) The monthly volume and/or mass of the carbon dioxide stream injected over the reporting period and the volume injected cumulatively over the life of the project;	RR & DM / Sect. 5.1.2				
(6) Monthly annulus fluid volume added; and	RR & DM / Sect. 5.1.2				
(7) The results of monitoring prescribed under § 146.90.	RR & DM / Sect. 5.1.4				
(b) Report, within 30 days, the results of:	RR & DM / Sect. 5.2				
(1) Periodic tests of mechanical integrity;					

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(2) Any well workover; and,					
(3) Any other test of the injection well conducted by the permittee if required by the Director.					
(c) Report, within 24 hours:	RR & DM / Sect. 5.4.1				
(1) Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW;					
(2) Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;					
(3) Any triggering of a shut-off system (i.e., down-hole or at the surface);					
(4) Any failure to maintain mechanical integrity; or.					
(5) Pursuant to compliance with the requirement at § 146.90(h) for surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any release of carbon dioxide to the atmosphere or biosphere.					
(d) Owners or operators must notify the Director in writing 30 days in advance of:	RR & DM / Sect. 5.2				
(1) Any planned well workover;					
(2) Any planned stimulation activities, other than stimulation for formation testing conducted under § 146.82; and					
(3) Any other planned test of the injection well conducted by the permittee.					
(e) Regardless of whether a State has primary enforcement responsibility, owners or operators must submit all required reports, submittals, and notifications under subpart H of this part to EPA in an electronic format approved by EPA.	RR & DM / Sect. 2				
(f) Records shall be retained by the owner or operator as follows:	RR & DM / Sect. 2.5				

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(1) All data collected under § 146.82 for Class VI permit applications shall be retained throughout the life of the geologic sequestration project and for 10 years following site closure.					
(2) Data on the nature and composition of all injected fluids collected pursuant to § 146.90(a) shall be retained until 10 years after site closure. The Director may require the owner or operator to deliver the records to the Director at the conclusion of the retention period.					
(3) Monitoring data collected pursuant to § 146.90(b) through (i) shall be retained for 10 years after it is collected.					
(4) Well plugging reports, post-injection site care data, including, if appropriate, data and information used to develop the demonstration of the alternative post-injection site care timeframe, and the site closure report collected pursuant to requirements at §§ 146.93(f) and (h) shall be retained for 10 years following site closure.					
(5) The Director has authority to require the owner or operator to retain any records required in this subpart for longer than 10 years after site closure.					
40 CFR § 146.92 - Injection well plugging.	Well Plugging, PISC, Site Closure (WP PISC & SC) / Sect. 2				
(a) Prior to the well plugging, the owner or operator must flush each Class VI injection well with a buffer fluid, determine bottomhole reservoir pressure, and perform a final external mechanical integrity test.	WP PISC & SC / Sect. 2.4				

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(b) Well plugging plan. The owner or operator of a Class VI well must prepare, maintain, and comply with a plan that is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The well plugging plan must be submitted as part of the permit application and must include the following information:	WP PISC & SC / Sect. 2.3				
(1) Appropriate tests or measures for determining bottomhole reservoir pressure;					
(2) Appropriate testing methods to ensure external mechanical integrity as specified in § 146.89;					
(3) The type and number of plugs to be used;					
(4) The placement of each plug, including the elevation of the top and bottom of each plug;					
(5) The type, grade, and quantity of material to be used in plugging. The material must be compatible with the carbon dioxide stream; and					
(6) The method of placement of the plugs.					
(c) Notice of intent to plug. The owner or operator must notify the Director in writing pursuant to § 146.91(e), at least 60 days before plugging of a well. At this time, if any changes have been made to the original well plugging plan, the owner or operator must also provide the revised well plugging plan. The Director may allow for a shorter notice period. Any amendments to the injection well plugging plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate.	WP PISC & SC / Sect. 2.2				
(d) Plugging report. Within 60 days after plugging, the owner or operator must submit, pursuant to § 146.91(e), a plugging report to the Director. The report must be certified as accurate by the owner or operator and by the person who performed the plugging operation (if other than the owner or operator.) The owner or operator shall retain the well plugging report for 10 years following site closure.	WP PISC & SC / Sect. 2.7				

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40 CFR § 146.93 - Post-injection site care and site closure.	Well Plugging, PISC, Site Closure (WP PISC & SC)	Liability Plan	2.0	2.3 + input from others	
(a) The owner or operator of a Class VI well must prepare, maintain, and comply with a plan for post-injection site care and site closure that meets the requirements of paragraph (a)(2) of this section and is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.	WP PISC & SC / Sect. 3				
(1) The owner or operator must submit the post-injection site care and site closure plan as a part of the permit application to be approved by the Director.	WP PISC & SC / Sect. 3.1				
(2) The post-injection site care and site closure plan must include the following information:	WP PISC & SC / Sect. 3.1.1				
(i) The pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s);					
(ii) The predicted position of the carbon dioxide plume and associated pressure front at site closure as demonstrated in the area of review evaluation required under § 146.84(c)(1);					
(iii) A description of post-injection monitoring location, methods, and proposed frequency;					
(iv) A proposed schedule for submitting post-injection site care monitoring results to the Director pursuant to § 146.91(e); and,					
(v) The duration of the post-injection site care timeframe and, if approved by the Director, the demonstration of the alternative post-injection site care timeframe that ensures non-endangerment of USDWs.					

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(3) Upon cessation of injection, owners or operators of Class VI wells must either submit an amended post-injection site care and site closure plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the plan is needed. Any amendments to the post-injection site care and site closure plan must be approved by the Director, be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate.	WP PISC & SC / Sect. 3.1.1				
(4) At any time during the life of the geologic sequestration project, the owner or operator may modify and resubmit the post-injection site care and site closure plan for the Director's approval within 30 days of such change.					
(b) The owner or operator shall monitor the site following the cessation of injection to show the position of the carbon dioxide plume and pressure front and demonstrate that USDWs are not being endangered.	WP PISC & SC / Sect. 3.3				
(1) Following the cessation of injection, the owner or operator shall continue to conduct monitoring as specified in the Director-approved post-injection site care and site closure plan for at least 50 years or for the duration of the alternative timeframe approved by the Director pursuant to requirements in paragraph (c) of this section, unless he/she makes a demonstration under (b)(2) of this section. The monitoring must continue until the geologic sequestration project no longer poses an endangerment to USDWs and the demonstration under (b)(2) of this section is submitted and approved by the Director.	WP PISC & SC / Sect. 3.3				

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(2) If the owner or operator can demonstrate to the satisfaction of the Director before 50 years or prior to the end of the approved alternative timeframe based on monitoring and other site-specific data, that the geologic sequestration project no longer poses an endangerment to USDWs, the Director may approve an amendment to the post-injection site care and site closure plan to reduce the frequency of monitoring or may authorize site closure before the end of the 50-year period or prior to the end of the approved alternative timeframe, where he or she has substantial evidence that the geologic sequestration project no longer poses a risk of endangerment to USDWs.	WP PISC & SC / Sect. 3.4				
(3) Prior to authorization for site closure, the owner or operator must submit to the Director for review and approval a demonstration, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs.	WP PISC & SC / Sect. 3.4				
(4) If the demonstration in paragraph (b)(3) of this section cannot be made (i.e., additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs) at the end of the 50-year period or at the end of the approved alternative timeframe, or if the Director does not approve the demonstration, the owner or operator must submit to the Director a plan to continue post-injection site care until a demonstration can be made and approved by the Director.					

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(c) Demonstration of alternative post-injection site care timeframe. At the Director's discretion, the Director may approve, in consultation with EPA, an alternative post-injection site care timeframe other than the 50 year default, if an owner or operator can demonstrate during the permitting process that an alternative post-injection site care timeframe is appropriate and ensures non-endangerment of USDWs. The demonstration must be based on significant, site-specific data and information including all data and information collected pursuant to §§ 146.82 and 146.83, and must contain substantial evidence that the geologic sequestration project will no longer pose a risk of endangerment to USDWs at the end of the alternative post-injection site care timeframe.	WP PISC & SC / Sect. 3.2.2				
(1) A demonstration of an alternative post-injection site care timeframe must include consideration and documentation of:					
(i) The results of computational modeling performed pursuant to delineation of the area of review under § 146.84;					
(ii) The predicted timeframe for pressure decline within the injection zone, and any other zones, such that formation fluids may not be forced into any USDWs; and/or the timeframe for pressure decline to pre-injection pressures;					
(iii) The predicted rate of carbon dioxide plume migration within the injection zone, and the predicted timeframe for the cessation of migration;					
(iv) A description of the site-specific processes that will result in carbon dioxide trapping including immobilization by capillary trapping, dissolution, and mineralization at the site;					
(v) The predicted rate of carbon dioxide trapping in the immobile capillary phase, dissolved phase, and/or mineral phase;					
(vi) The results of laboratory analyses, research studies, and/or field or site-specific studies to verify the information required in paragraphs (iv) and (v) of this section;					

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(vii) A characterization of the confining zone(s) including a demonstration that it is free of transmissive faults, fractures, and micro-fractures and of appropriate thickness, permeability, and integrity to impede fluid (e.g., carbon dioxide, formation fluids) movement;					
(viii) The presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic sequestration project or any other projects in proximity to the predicted/modeled, final extent of the carbon dioxide plume and area of elevated pressure;					
(ix) A description of the well construction and an assessment of the quality of plugs of all abandoned wells within the area of review;					
(x) The distance between the injection zone and the nearest USDWs above and/or below the injection zone; and					
(xi) Any additional site-specific factors required by the Director.					
(2) Information submitted to support the demonstration in paragraph (c)(1) of this section must meet the following criteria:					
(i) All analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards;					
(ii) Estimation techniques must be appropriate and EPA-certified test protocols must be used where available;					
(iii) Predictive models must be appropriate and tailored to the site conditions, composition of the carbon dioxide stream and injection and site conditions over the life of the geologic sequestration project;					
(iv) Predictive models must be calibrated using existing information (e.g., at Class I, Class II, or Class V experimental technology well sites) where sufficient data are available;					

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(v) Reasonably conservative values and modeling assumptions must be used and disclosed to the Director whenever values are estimated on the basis of known, historical information instead of site-specific measurements;					
(vi) An analysis must be performed to identify and assess aspects of the alternative post-injection site care timeframe demonstration that contribute significantly to uncertainty. The owner or operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration.					
(vii) An approved quality assurance and quality control plan must address all aspects of the demonstration; and,					
(viii) Any additional criteria required by the Director.					
(d) Notice of intent for site closure. The owner or operator must notify the Director in writing at least 120 days before site closure. At this time, if any changes have been made to the original post-injection site care and site closure plan, the owner or operator must also provide the revised plan. The Director may allow for a shorter notice period.	WP PISC & SC / Sect. 4.1				
(e) After the Director has authorized site closure, the owner or operator must plug all monitoring wells in a manner which will not allow movement of injection or formation fluids that endangers a USDW.	WP PISC & SC / Sect. 4.2				
(f) The owner or operator must submit a site closure report to the Director within 90 days of site closure, which must thereafter be retained at a location designated by the Director for 10 years. The report must include:	WP PISC & SC / Sect. 4.3				
(1) Documentation of appropriate injection and monitoring well plugging as specified in § 146.92 and paragraph (e) of this section. The owner or operator must provide a copy of a survey plat which has been submitted to the local zoning authority designated by the Director. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks. The owner or operator must also submit a copy of the plat to the Regional Administrator of the appropriate EPA Regional Office;					

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(2) Documentation of appropriate notification and information to such State, local and Tribal authorities that have authority over drilling activities to enable such State, local, and Tribal authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zone(s); and					
(3) Records reflecting the nature, composition, and volume of the carbon dioxide stream.					
(g) Each owner or operator of a Class VI injection well must record a notation on the deed to the facility property or any other document that is normally examined during title search that will in perpetuity provide any potential purchaser of the property the following information:	WP PISC & SC / Sect. 4.3				
(1) The fact that land has been used to sequester carbon dioxide;					
(2) The name of the State agency, local authority, and/or Tribe with which the survey plat was filed, as well as the address of the Environmental Protection Agency Regional Office to which it was submitted; and					
(3) The volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.					
(h) The owner or operator must retain for 10 years following site closure, records collected during the post-injection site care period. The owner or operator must deliver the records to the Director at the conclusion of the retention period, and the records must thereafter be retained at a location designated by the Director for that purpose.	WP PISC & SC / Sect. 4.3				
40 CFR § 146.94 - Emergency and remedial response.	No EPA Guidance	Emergency & Remedial Response Plan			PacifiCorp

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(a) As part of the permit application, the owner or operator must provide the Director with an emergency and remedial response plan that describes actions the owner or operator must take to address movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and post-injection site care periods. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.		Not Phase I			
(b) If the owner or operator obtains evidence that the injected carbon dioxide stream and associated pressure front may cause an endangerment to a USDW, the owner or operator must:					
(1) Immediately cease injection;					
(2) Take all steps reasonably necessary to identify and characterize any release;					
(3) Notify the Director within 24 hours; and					
(4) Implement the emergency and remedial response plan approved by the Director.					
(c) The Director may allow the operator to resume injection prior to remediation if the owner or operator demonstrates that the injection operation will not endanger USDWs.					
(d) The owner or operator shall periodically review the emergency and remedial response plan developed under paragraph (a) of this section. In no case shall the owner or operator review the emergency and remedial response plan less often than once every five years. Based on this review, the owner or operator shall submit an amended emergency and remedial response plan or demonstrate to the Director that no amendment to the emergency and remedial response plan is needed. Any amendments to the emergency and remedial response plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate. Amended plans or demonstrations shall be submitted to the Director as follows:					
(1) Within one year of an area of review reevaluation;					

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(2) Following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the Director; or					
(3) When required by the Director.					
40 CFR § 146.95 - Class VI injection depth waiver requirements.	No EPA Guidance		3.0	3.1	UU: Chan, UGS: Morgan
This section sets forth information which an owner or operator seeking a waiver of the Class VI injection depth requirements must submit to the Director; information the Director must consider in consultation with all affected Public Water System Supervision Directors; the procedure for Director—Regional Administrator communication and waiver issuance; and the additional requirements that apply to owners or operators of Class VI wells granted a waiver of the injection depth requirements.					
(a) In seeking a waiver of the requirement to inject below the lowermost USDW, the owner or operator must submit a supplemental report concurrent with permit application. The supplemental report must include the following,					
(1) A demonstration that the injection zone(s) is/are laterally continuous, is not a USDW, and is not hydraulically connected to USDWs; does not outcrop; has adequate injectivity, volume, and sufficient porosity to safely contain the injected carbon dioxide and formation fluids; and has appropriate geochemistry.					
(2) A demonstration that the injection zone(s) is/are bounded by laterally continuous, impermeable confining units above and below the injection zone(s) adequate to prevent fluid movement and pressure buildup outside of the injection zone(s); and that the confining unit(s) is/are free of transmissive faults and fractures. The report shall further characterize the regional fracture properties and contain a demonstration that such fractures will not interfere with injection, serve as conduits, or endanger USDWs.					

DRAFT	EPA Class VI Guidance Document / Sections	CarbonSAFE Phase I Project Plan	Phase I Task	Phase I Subtask	Responsible Person(s)
(3) A demonstration, using computational modeling, that USDWs above and below the injection zone will not be endangered as a result of fluid movement. This modeling should be conducted in conjunction with the area of review determination, as described in § 146.84, and is subject to requirements, as described in § 146.84(c), and periodic reevaluation, as described in § 146.84(e).					
(4) A demonstration that well design and construction, in conjunction with the waiver, will ensure isolation of the injectate in lieu of requirements at 146.86(a)(1) and will meet well construction requirements in paragraph (f) of this section.					
(5) A description of how the monitoring and testing and any additional plans will be tailored to the geologic sequestration project to ensure protection of USDWs above and below the injection zone(s), if a waiver is granted.					
(6) Information on the location of all the public water supplies affected, reasonably likely to be affected, or served by USDWs in the area of review.					
(7) Any other information requested by the Director to inform the Regional Administrator's decision to issue a waiver.					
(b) To inform the Regional Administrator's decision on whether to grant a waiver of the injection depth requirements at §§ 144.6 of this chapter, 146.5(f), and 146.86(a)(1), the Director must submit, to the Regional Administrator, documentation of the following:					
(1) An evaluation of the following information as it relates to siting, construction, and operation of a geologic sequestration project with a waiver:					
(i) The integrity of the upper and lower confining units;					
(ii) The suitability of the injection zone(s) (e.g., lateral continuity; lack of transmissive faults and fractures; knowledge of current or planned artificial penetrations into the injection zone(s) or formations below the injection zone);					
(iii) The potential capacity of the geologic formation(s) to sequester carbon dioxide, accounting for the availability of alternative injection sites;					

DRAFT	EPA Class VI Guidance Document / Sections	CarbonSAFE Phase I Project Plan	Phase I Task	Phase I Subtask	Responsible Person(s)
(iv) All other site characterization data, the proposed emergency and remedial response plan, and a demonstration of financial responsibility;					
(v) Community needs, demands, and supply from drinking water resources;					
(vi) Planned needs, potential and/or future use of USDWs and non-USDWs in the area;					
(vii) Planned or permitted water, hydrocarbon, or mineral resource exploitation potential of the proposed injection formation(s) and other formations both above and below the injection zone to determine if there are any plans to drill through the formation to access resources in or beneath the proposed injection zone(s)/formation(s);					
(viii) The proposed plan for securing alternative resources or treating USDW formation waters in the event of contamination related to the Class VI injection activity; and,					
(ix) Any other applicable considerations or information requested by the Director.					
(2) Consultation with the Public Water System Supervision Directors of all States and Tribes having jurisdiction over lands within the area of review of a well for which a waiver is sought.					
(3) Any written waiver-related information submitted by the Public Water System Supervision Director(s) to the (UIC) Director.					
(c) Pursuant to requirements at § 124.10 of this chapter and concurrent with the Class VI permit application notice process, the Director shall give public notice that a waiver application has been submitted. The notice shall clearly state:					
(1) The depth of the proposed injection zone(s);					
(2) The location of the injection well(s);					
(3) The name and depth of all USDWs within the area of review;					
(4) A map of the area of review;					

DRAFT	EPA Class VI Guidance Document / Sections	CarbonSAFE Phase I Project Plan	Phase I Task	Phase I Subtask	Responsible Person(s)
(5) The names of any public water supplies affected, reasonably likely to be affected, or served by USDWs in the area of review; and,					
(6) The results of UIC-Public Water System Supervision consultation required under paragraph (b)(2) of this section.					
(d) Following public notice, the Director shall provide all information received through the waiver application process to the Regional Administrator. Based on the information provided, the Regional Administrator shall provide written concurrence or non-concurrence regarding waiver issuance.					
(1) If the Regional Administrator determines that additional information is required to support a decision, the Director shall provide the information. At his or her discretion, the Regional Administrator may require that public notice of the new information be initiated.					
(2) In no case shall a Director of a State-approved program issue a waiver without receipt of written concurrence from the Regional Administrator.					
(e) If a waiver is issued, within 30 days of waiver issuance, EPA shall post the following information on the Office of Water's Web site:					
(1) The depth of the proposed injection zone(s);					
(2) The location of the injection well(s);					
(3) The name and depth of all USDWs within the area of review;					
(4) A map of the area of review;					
(5) The names of any public water supplies affected, reasonably likely to be affected, or served by USDWs in the area of review; and					
(6) The date of waiver issuance.					
(f) Upon receipt of a waiver of the requirement to inject below the lowermost USDW for geologic sequestration, the owner or operator of the Class VI well must comply with:					
(1) All requirements at §§ 146.84, 146.85, 146.87, 146.88, 146.89, 146.91, 146.92, and 146.94;					

DRAFT	EPA Class VI Guidance Document / Sections	CarbonSAFE Phase I Project Plan	Phase I Task	Phase I Subtask	Responsible Person(s)
(2) All requirements at § 146.86 with the following modified requirements:					
(i) The owner or operator must ensure that Class VI wells with a waiver are constructed and completed to prevent movement of fluids into any unauthorized zones including USDWs, in lieu of requirements at § 146.86(a)(1).					
(ii) The casing and cementing program must be designed to prevent the movement of fluids into any unauthorized zones including USDWs in lieu of requirements at § 146.86(b)(1).					
(iii) The surface casing must extend through the base of the nearest USDW directly above the injection zone and be cemented to the surface; or, at the Director's discretion, another formation above the injection zone and below the nearest USDW above the injection zone.					
(3) All requirements at § 146.90 with the following modified requirements:					
(i) The owner or operator shall monitor the groundwater quality, geochemical changes, and pressure in the first USDWs immediately above and below the injection zone(s); and in any other formations at the discretion of the Director.					
(ii) Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) by using direct methods to monitor for pressure changes in the injection zone(s); and, indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the Director determines, based on site-specific geology, that such methods are not appropriate.					
(4) All requirements at § 146.93 with the following, modified post-injection site care monitoring requirements:					
(i) The owner or operator shall monitor the groundwater quality, geochemical changes and pressure in the first USDWs immediately above and below the injection zone; and in any other formations at the discretion of the Director.					

DRAFT	EPA Class VI Guidance Document / Sections	CarbonSAFE Phase I Project Plan	Phase I Task	Phase I Subtask	Responsible Person(s)
(ii) Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) by using direct methods in the injection zone(s); and indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the Director determines based on site-specific geology, that such methods are not appropriate;					
(5) Any additional requirements requested by the Director designed to ensure protection of USDWs above and below the injection zone(s).					

Rocky Mountain CarbonSAFE Phase I

Appendix M

Area of Review (AoR) Evaluation and Corrective Action Guidance

UIC Class VI Requirements

Area of Review (AoR) Evaluation and Corrective Action Guidance

Prepared by Candace Cady

(Condensation of EPA's UIC Class VI Well
Area of Review Evaluation and Corrective Action Guidance)

UTAH DEPARTMENT OF ENVIRONMENTAL QUALITY
WATER QUALITY

! ! DISCLAIMER ! !

This document is meant to make the CarbonSAFE Rocky Mountains team aware of EPA's Class VI injection well requirements as they are presented in the several guidance documents prepared by EPA. It is NOT meant to be a stand-alone document. I encourage you, I implore you to read the relevant sections of the guidance documents, the final Class VI rule, and all references contained therein which pertain to your particular task on the CarbonSAFE team!

Overview of AoR & CA Requirements

- Prepare, maintain, and comply with an AoR and Corrective Action Plan that includes all of the required elements of the plan [40 CFR 146.84(b)];
- Delineate the AoR using computational modeling and identify all wells that require corrective action [40 CFR 146.84(c)];
- Perform all required corrective action on wells in the AoR [40 CFR 146.84(d)];
- Re-evaluate the AoR throughout the life of the project [40 CFR 146.84(e)];
- Ensure that the Emergency and Remedial Response Plan and financial responsibility demonstration account for the most recently approved AoR [40 CFR 146.84(f)]; and
- Retain modeling inputs and data used to support AoR re-evaluations for 10 years [40 CFR 146.84(g)].

Organization of this Guidance

- Computational Modeling for Geologic Sequestration (pages 7 – 29)
- AoR Delineation Using Computational Models (pages 30 – 49)
- Identifying Artificial Penetrations and Performing Corrective Action (pages 50 – 67)
- AoR Re-evaluation (pages 68 – 77)

Activities Relating to AoR

- Prior to Issuance of a Class VI Permit:
  - Collection of relevant site characterization and operational data [40 CFR 146.82(a)(3), 146.82(a)(5), 146.82(a)(6), and 146.83];
  - Determination of relevant operational data that will inform the AoR modeling [40 CFR 146.82(a)(7), and 146.82(a)(10)-(11)];
  - Development of an AoR and Corrective Action Plan [40 CFR 146.82(a)(13) and 146.84(b)];
  - Performing AoR modeling and delineation [40 CFR 146.82(a)(2)]; and
  - Identification and assessment of artificial penetrations within the AoR [40 CFR 146.82(a)(4)].

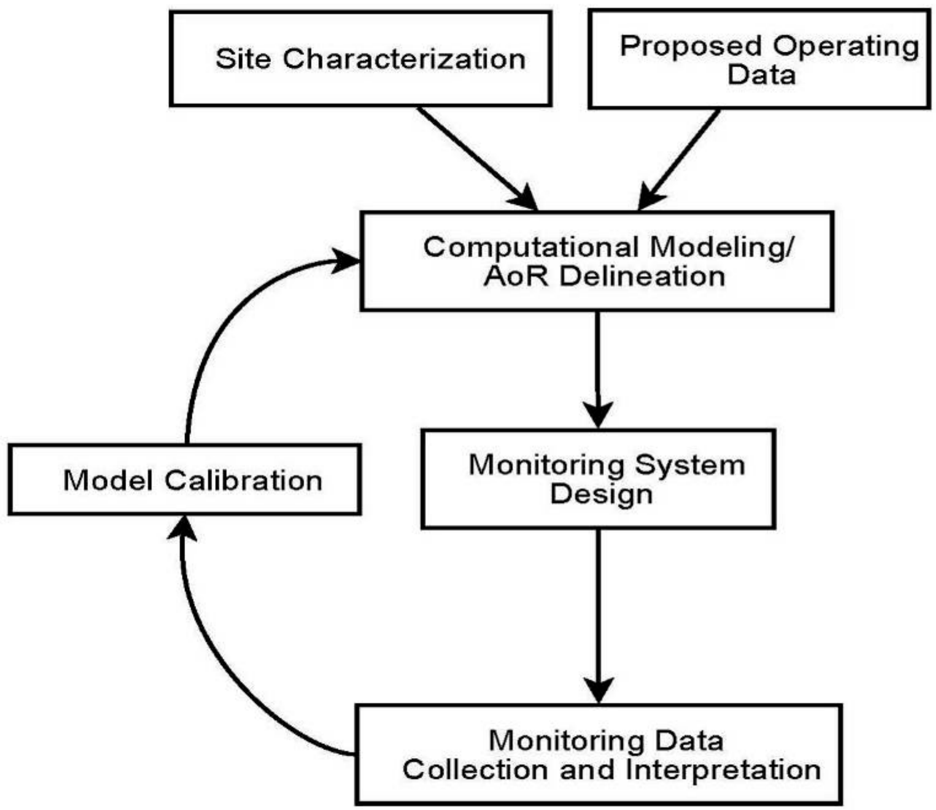
Activities Relating to AoR (cont.)

- Prior to Being Granted Authorization to Inject into Class VI Well:
  - Collection and/or updating of relevant site characterization and operational data that will inform AoR modeling
    [40 CFR 146.82(c)(2)-(5), 146.82(c)(7), and 146.83];
  - Identification of any needed updates to the AoR and Corrective Action Plan
    [40 CFR 146.82(c)(9)];
  - Finalizing AoR modeling and delineation
    [40 CFR 146.82(c)(1)]; and
  - Performing corrective action on those penetrations that may serve as a conduit for fluid movement
    [40 CFR 146.82(c)(6) and 146.84(d)].

Activities Relating to AoR (cont.)

- During Injection and Post-Injection Site Care (PISC):
  - Re-evaluation of the AoR periodically, at least once every five (5) years [40 CFR 146.82(c)(9) and 146.84(e)], and updating the AoR and Corrective Action Plan; and
  - If phased corrective action is approved or when additional corrective action is warranted based on AoR re-evaluations, performing corrective action [40 CFR 146.82(c)(6) and 146.84(d)].

Relationship between Site Characterization, Modeling, & Monitoring



Computational Modeling for Geologic Sequestration

- Modeled Processes
- Model Parameters
- Computational Approaches
- Model Uncertainty & Sensitivity Analyses
- Model Calibration
- Existing Codes used for Development of GS Models

Computational Modeling for Geologic Sequestration

Modeled Processes

- Modeled Processes
  - multiphase flow – Class VI Rule requires inclusion in computational modeling.
  - reactive transport
  - geomechanical processes
  - coupled multiphase flow & geomechanical processes
  - coupled multiphase flow & geochemical processes
  - interactive coupling of all 3 processes where geochemical & geomechanical processes are significant

Computational Modeling for Geologic Sequestration

Model Parameters

Table 2.1

Computational Modeling for Geologic Sequestration

Computational Approaches

- the guidance discusses the 'numerical formulation of the governing equations applied over a spatially discretized model domain that defines the spatial extent and resolution of the problem (i.e., the model grid). This formulation is solved by a numerical method, such as finite element or finite difference approximation.'
- the guidance further discusses the processes which are most suitably addressed by numerical methods some of which are:
  - fluid and heat flow;
  - phase changes, mass transfer, and chemical reactions;
  - steady-state and transient problems relative to injection & withdrawal rates.

Computational Modeling for Geologic Sequestration

Computational Approaches (cont.)

- the guidance also discusses the use of analytical, semi-analytical and hybrid methods to complement numerical modeling efforts in AoR delineation
- these methods may be useful:
  - for assessing transport of carbon dioxide through abandoned well bores;
  - as screening tools to quickly assess potential storage sites;
  - as a relatively simple comparative check on numerical modeling results.

Computational Modeling for Geologic Sequestration

Model Uncertainty & Sensitivity Analyses

- the guidance discusses model uncertainty due to:
  - uncertainties in governing equations and model framework due to incomplete scientific data or lack of knowledge or data on the behavior of supercritical CO_2 in the subsurface or simplifications
  - parameter uncertainties due to lack of data, poor data quality, inherent variability in natural systems
  - process and scale dependency

Computational Modeling for Geologic Sequestration

Model Uncertainty & Sensitivity Analyses (cont.)

- the guidance also discusses characterization of parameter uncertainty by conducting a model sensitivity analysis
  - provides indication of those modeling parameters that are most sensitive (i.e., that most impact predictions of carbon dioxide migration, trapping, and pressure changes), and
  - provides guidance for what parameters to focus on during data collection, parameter estimation, and model calibration.

Model Calibration

- the guidance discusses the concept of model calibration and the use of manual and automated manual calibration
- model calibration of the Frio Brine Pilot Project is presented

Computational Modeling for Geologic Sequestration

Existing Codes used for Development of GS Models

- the guidance briefly discusses existing codes used for development of GS models
  - petroleum reservoir codes: STARS, GEM, ECLIPSE, CHEARS
  - US DOE: STOMP, CRUNCH, TOUGH-series

AoR Delineation Using Computational Models

- AoR Delineation Class VI Rule Requirements
- Data Collection and Compilation
- Model Development
- AoR Delineation Based on Model Results
- Reporting AoR Delineation Results to the UIC Program Director

AoR Delineation Using Computational Models

AoR Delineation Class VI Rule Requirements

- 40 CFR 146.84(a): The AoR is the region surrounding the GS project where USDWs may be endangered by the injection activity. The AoR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.

AoR Delineation Using Computational Models

AoR Delineation Class VI Rule Requirements (cont.)

- 40 CFR 146.84(c)(1): Owners or operators of Class VI wells must predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the UIC Program Director. The model must:

AoR Delineation Using Computational Models

AoR Delineation Class VI Rule Requirements (cont.)

(i) Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s), and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the GS project;

(ii) Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and

(iii) Consider potential migration through faults, fractures, and artificial penetrations.

AoR Delineation Using Computational Models

Data Collection and Compilation

- the guidance emphasizes that the extent to which site and operational conditions are realistically represented determines the validity of the resulting model predictions. (aka: Avoid garbage in, garbage out syndrome!)
  - Site Hydrology - Regional and site-specific geology provide the foundations of the computational model used to delineate the AoR.
  - Operational Data - 40 CFR 146.84(c)(1)(i) requires that the model be based on .... and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project;

AoR Delineation Using Computational Models

Model Development

- with regards to the development of computational models, the guidance discusses the following major points:
  - Conceptual Model of the Proposed Injection Site
  - Determination of Physical Processes to be Included in the Computational Model
  - Computational Model Design
    - Computational Code Determination
    - Model Spatial Extent, Discretization, and Boundary Conditions
    - Model Timeframe
    - Parameterization
  - Executing the Computational Model

AoR Delineation Using Computational Models

AoR Delineation Based on Model Results

- 40 CFR 146.84(a) and 40 CFR 146.84(c)(1) require that the predicted AoR, which is based on the computational modeling, submitted with the Class VI permit application be based on a delineation of the area where the GS project may cause endangerment of USDWs
- at the discretion of the UIC Program Director, a single AoR modeling exercise may be conducted for a single GS project with multiple wells
- boundaries of AoR are based on simulated predictions of the extent of the separate-phase (i.e. supercritical, liquid, or gaseous) plume and pressure front.

AoR Delineation Using Computational Models

AoR Delineation Based on Model Results (cont.)

- EPA recommends that the AoR encompass the maximum extent of the separate-phase plume or pressure front over the lifetime of the project and entire timeframe of the model simulations.
- definition of pressure front - the minimum pressure within the injection zone necessary to cause fluid flow from the injection zone into the formation matrix of the USDW through a hypothetical conduit (i.e., artificial penetration) that is perforated in both intervals (the injection interval and the USDW interval).

AoR Delineation Using Computational Models

AoR Delineation Based on Model Results (cont.)

- the guidance describes the following several methods for estimating the pressure front based on various assumptions
  - *Pressure front based on bringing injection zone and USDW to equivalent hydraulic heads (applicable to under-pressurized case only).*
  - *Pressure front based on displacing fluid initially present in the borehole (applicable to hydrostatic case only).*
  - *Methods for over-pressurized cases.*
- the guidance presents, in detail, a hypothetical example of an AoR delineation

AoR Delineation Using Computational Models

Reporting AoR Delineation Results to the UIC Program Director

- 40 CFR 146.82(a)(13) requires the submittal of the AoR and Corrective Action Plan with the initial permit application
- Information pertaining to how this plan should be submitted is provided in the *UIC Program Class VI Well Project Plan Development Guidance.*
- the guidance lists the 10 data elements EPA recommends be submitted with the permit application
- 40 CFR 146.82(c)(1) requires that the final delineated AoR based on computational modeling is submitted to the UIC Program Director prior to receiving authorization to inject.

Identifying Artificial Penetrations & Performing Corrective Action

- Rule Requirements
- Identifying Artificial Penetrations within the AoR
- Assessing Identified Abandoned Wells
- Performing Corrective Action on Wells within the AoR
- Reporting Well Identification, Assessment, and Corrective Action to the UIC Program Director

Identifying Artificial Penetrations & Performing CA

Rule Requirements

- 40 CFR 146.84(c)(2): Using methods approved by the UIC Program Director, identify all penetrations, including active and abandoned wells and underground mines, in the AoR that may penetrate the confining zone(s). Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/ or completion, and any additional information the UIC Program Director may require;
- 40 CFR 146.84(c)(3): Determine which abandoned wells in the AoR have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs, including use of materials compatible with the carbon dioxide stream;

Identifying Artificial Penetrations & Performing CA

Rule Requirements (cont.)

- 40 CFR 146.84(d): Perform corrective action on all wells in the AoR that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate;
- 40 CFR 146.84(e)(2): During the AoR reevaluation process, identify all wells in the reevaluated AoR that require corrective action in the same manner specified in 40 CFR 146.84(c);
- 40 CFR 146.84(e)(3): Perform corrective action on wells requiring corrective action in the reevaluated AoR in the same manner specified in 40 CFR 146.84(d);
- 40 CFR 146.84(e)(4): Revise the AoR and Corrective Action Plan as necessary whenever the AoR is reevaluated.

Identifying Artificial Penetrations & Performing CA

Identifying Artificial Penetrations within the AoR

- 40 CFR 146.84(d) requires identified abandoned wells that have been improperly plugged or not plugged at all (such penetrations can provide unimpeded flow conduits out of the injection zone) must be properly plugged in order to prevent endangerment of USDWs.
- the guidance describes the following methods for identifying artificial penetrations:
  - historical research
  - site reconnaissance
  - aerial and satellite imagery review
  - geophysical surveys – magnetic methods, electromagnetic methods, ground penetrating radar,

Identifying Artificial Penetrations & Performing CA

Assessing Identified Abandoned Wells

- the guidance discusses the process of assessing each identified artificial penetration for the potential to serve as a conduit for fluid movement.
  - abandoned well plugging records review
  - abandoned well field testing
    - after all the available records have been reviewed, any wells located within the AoR that cannot be proven to have plugs adequate to prevent migration of carbon dioxide or formation fluids out of the injection zone must be evaluated by field tests in order to determine the quality of plugging, as required by 40 CFR 146.84(c)(3).
    - the guidance describes several tools used for assessing the integrity of abandoned wells.

Identifying Artificial Penetrations & Performing CA

Performing Corrective Action on Wells within the AoR

- the guidance includes a graphical well evaluation decision tree – Fig. 4-3
- the Class VI Rule allows for corrective action on a phased basis
- acceptable forms of corrective action include well plugging and/or remedial cementing of the improperly abandoned wells. Both are described in the guidance.
- EPA recommends performing enhanced monitoring in the vicinity of improperly abandoned wells, including ground water monitoring and using indirect geophysical techniques for obtaining monitoring results. (See the *UIC Program Class VI Well Testing and Monitoring Guidance* for appropriate monitoring.)

Identifying Artificial Penetrations & Performing CA

Reporting Well Identification, Assessment, and CA to the UIC Program Director

- the guidance emphasizes that the AoR and Corrective Action Plan (see the *UIC Program Class VI Well Project Plan Development Guidance* for details in the development of this plan) must indicate what well identification and assessments will be used and how corrective action will be conducted.

AoR Re-Evaluation

- Class VI Rule Requirements Related to AoR Re-evaluation
- Conditions Warranting an AoR Re-evaluation
- Performing an AoR Re-evaluation

AoR Re-Evaluation

Class VI Rule Requirements Related to AoR Re-evaluation

- 40 CFR 146.84(e): At the minimum fixed frequency, not to exceed five years, as specified in the AoR and Corrective Action Plan, or when monitoring and operational conditions warrant, owners or operators must:

  (1) Re-evaluate the AoR in the same manner specified in 40 CFR 146.84(c)(1);

  (2) Identify all wells in the re-evaluated AoR that require corrective action in the same manner specified in 40 CFR 146.84(c);

  (3) Perform corrective action on wells requiring corrective action in the re-evaluated AoR in the same manner specified in 40 CFR 146.84(d); and

AoR Re-Evaluation

Class VI Rule Requirements Related to AoR Re-evaluation (cont.)

(4) Submit an amended AoR and Corrective Action Plan or demonstrate to the UIC Program Director through monitoring data and modeling results that no amendment to the AoR and Corrective Action Plan is needed. Any amendments to the AoR and Corrective Action Plan must be approved by the UIC Program Director, must be incorporated into the permit, and are subject to the permit modification requirements at 40 CFR 144.39 or 144.41, as appropriate.

AoR Re-Evaluation

Conditions Warranting an AoR Re-evaluation

- AoR re-evaluation is required at a minimum fixed frequency of at least once every five years, or when monitoring and operational conditions warrant. EPA recommends, and the guidance describes, that monitoring and operational conditions that may warrant a re-evaluation of the AoR include:
  - Significant changes in site operations that may alter model predictions and the AoR delineation;
  - Monitoring results for the injected carbon dioxide plume and/or the associated pressure front that differ significantly from model predictions; or
  - New site characterization data obtained that may significantly change model predictions and the delineated AoR.

Performing an AoR Re-evaluation

- the guidance describes the steps in performing an AoR re-evaluation including:
  - comparison of plume monitoring data with model predictions
  - comparison of pressure monitoring data with model predictions
  - evaluate outcome of monitoring data and model comparison
  - revise the AoR delineation (and model) and AoR and Corrective Action Plan, if necessary
- the guidance presents a hypothetical example of an AoR re-evaluation and a presentation of the revised AoR

Rocky Mountain CarbonSAFE Phase I

Appendix N

Site Characterization Guidance

UIC Class VI Requirements

Site Characterization Guidance

Prepared by Candace Cady

(Condensation of EPA's UIC Class VI Well Site Characterization Guidance)

UTAH DEPARTMENT OF ENVIRONMENTAL QUALITY
WATER QUALITY

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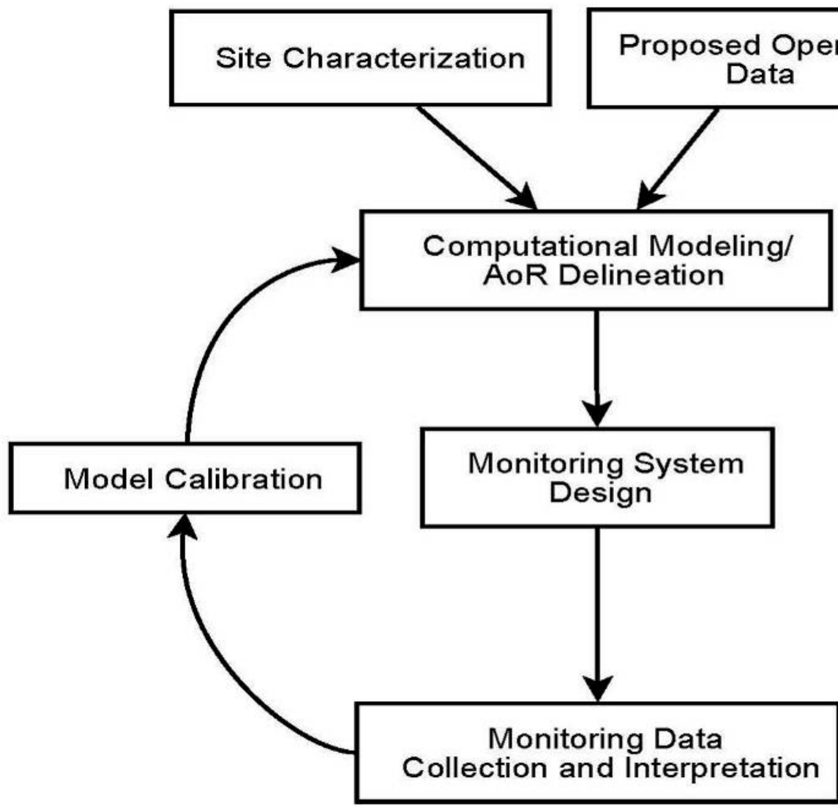
Organization of this Guidance

- Activities Performed Prior to Construction of a Class VI Well
  - ✓ information required for Class VI permit application
  - ✓ meet requirements of 40 CFR 146.82(a)(2), (3), (5), and (6)
- Data Synthesis for Demonstration of Site Suitability
- Activities Performed Prior to Operation of a Class VI Well
  - ✓ activities & information before injection may be authorized
  - ✓ meet requirements of 40 CFR 146.82(c)(2)–(4) and (7), and 146.87(b)–(e).

Relationship between Site Characterization, Modeling, & Monitoring



Prior to Construction

- Regional Geology, Hydrogeology, & Local Structural Geology (pages 9 - 11)
- Map of Injection Well, Area of Review (AoR), Surface Water Bodies, Artificial Penetrations, & Faults (page 11 - 13)
- Detailed Geology & Hydrogeologic Site Characterization within AoR (page 13 - 44)

Class VI AoR Delineation Requirements

- 40 CFR 146.84(a): The AoR is the region surrounding the GS project where USDWs may be endangered by the injection activity. The AoR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.

Class VI AoR Delineation Requirements (cont.)

- 40 CFR 146.84(c)(1): Owners or operators of Class VI wells must predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the UIC Program Director. The model must:

Class VI AoR Delineation Requirements (cont.)

(i) Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s), and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the GS project;

(ii) Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and

(iii) Consider potential migration through faults, fractures, and artificial penetrations.

Regional Geology, Hydrogeology, & Local Structural Geology

- 40 CFR 146.82(a)(3)(vi) requires submittal of geologic & topographic maps & cross sections illustrating regional geology, hydrogeology, geologic structure of local area surrounding the project area
- the guidance discusses the features to highlight in maps & accompanying narrative:
  - ✓ names, lithologies, & depths of injection formation(s) & confining zone(s)
  - ✓ depths, extent, & groundwater flow patterns of regional USDW
  - ✓ brief synopsis of geologic history of project site
  - ✓ regional faults, fault types, trends, & whether they transect the injection formation(s) and/or confining zone(s)

Regional Geology, Hydrogeology, & Local Structural Geology (cont.)

✓ structural geology of the local area

- presence & trends of folds
- whether proposed storage site will be bounded by faults or other structural features.

- UIC Director may require characterization of secondary confining zone [40 CFR 146.83(b)].

Map of Injection Well, Area of Review, Surface Water Bodies, Artificial Penetrations, & Faults

- 40 CFR 146.82(a)(2) requires submittal of an Area of Review (AoR) map showing existing information in the public record regarding:
  - ✓ surface bodies of water & springs
  - ✓ mines (both surface & subsurface) & quarries
  - ✓ surface features, including structures intended for human occupancy
  - ✓ political boundaries such as state, tribal & territorial boundaries
  - ✓ surface trace of all known & suspected faults
  - ✓ number or name, & location of all injection wells, producing wells, abandoned wells, plugged wells, dry holes, or deep stratigraphic holes
  - ✓ state- or EPA-approved subsurface cleanup sites.

Map of Injection Well, Area of Review, Surface Water Bodies, Artificial Penetrations, & Faults (cont.)

- 40 CFR 146.82(a)(4) requires tabulation of all wells within AoR that penetrate the injection or confining zone(s) – artificial penetrations – to include:
  - ✓ description of each well's type, construction, date drilled, location and depth
  - ✓ record of plugging and/or completion
  - ✓ any additional information UIC Director may require.

Detailed Geology & Hydrogeologic Site Characterization

- Maps & Cross Sections of AoR
- Fault & Fractures in AoR
- Depth, Areal Extent, & Thickness of Injection & Confining Zones
- Petrology & Mineralogy of Injection & Confining Zones
- Porosity, Permeability, & Capillary Pressure of Injection & Confining Zones
- Geomechanical Characterization
- Seismic History
- Hydrology & Hydrogeology of AoR
- Baseline Geochemical Characterization
- Geophysical Characterization
- Surface Air & Soil Gas Monitoring

Detailed Geology & Hydrogeologic Site Characterization

Maps & Cross Sections of AoR

- 40 CFR 146.82(a)(3)(i) requires submittal of maps & cross sections of AoR
  - ✓ topographic maps
  - ✓ geologic maps w/ cross sections & stratigraphic columns summarizing lithology, sequence of geologic units (including injection & confining zones and USDWs), approximate formation thicknesses, lateral extent of units, and correlation of units in vicinity of project and across region

Detailed Geology & Hydrogeologic Site Characterization

Maps & Cross Sections of AoR (cont.)

- narrative accompanying maps and cross sections of the AoR should be similar in scope to the evaluation of regional geology, but provide more detail on the AoR; narrative should highlight lateral extent of injection formation and show that it is continuous throughout proposed site; at a minimum, the following should be described:
  - ✓ formation names, lithologies, and depths of the injection formation(s), confining zone(s), and USDWs within the proposed AoR;
  - ✓ general description of stratigraphy, including the vertical distance and formations separating the injection formation from USDWs; and
  - ✓ structural geology of the project site, including whether the proposed storage site will be bounded or influenced by a structural trap (e.g., faults or a dome).

Detailed Geology & Hydrogeologic Site Characterization

Faults & Fractures in the AoR

- 40 CFR 146.82(a)(3)(ii) requires submittal of information on location, orientation, and properties of known or suspected faults & fractures that may transect the confining zone(s) in the AoR and a determination that they would not interfere with containment.
- This information is needed to demonstrate that the site has a confining zone(s) free of transmissive faults or fractures and that will allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s). Evaluation of fault stability and fault or fracture sealing capacity is needed to demonstrate that faults will not interfere with containment of the carbon dioxide.

Detailed Geology & Hydrogeologic Site Characterization

Faults & Fractures in the AoR (cont.)

- EPA recommends obtaining information on fault in injection zone including whether a fault zone consists of one major plane or a series of faults that may collectively provide a conduit for fluid movement through confining zone, especially if faults intersect lenses of high permeability.
- faults and fractures shall be assessed for stability and the likelihood that they are sealing

Detailed Geology & Hydrogeologic Site Characterization

Faults & Fractures in the AoR (cont.)

- in describing faults & fractures, EPA recommends the following information:
  - ✓ location and characteristics of the fault or fracture (e.g., geometry, depth, fault displacement, units juxtaposed by fault);
  - ✓ formations intersected or transected by the fault or fracture;
  - ✓ methods and results of fault stability analyses and comparison to preliminary anticipated (modeled) pressures during the injection phase of the project; and
  - ✓ information on faults and fractures in the lower confining zone (in cases where an injection depth waiver is sought).

Detailed Geology & Hydrogeologic Site Characterization

Faults & Fractures in the AoR (cont.)

- in demonstating non-transmissivity of faults and fractures, EPA recommends the following information:
  - ✓ description of the approach used to infer whether a fault or fracture is transmissive;
  - ✓ summary table of data used to formulate the estimate;
  - ✓ supporting data and information (e.g., analyses of core samples, results of geophysical surveys, pore pressure data, maps, and cross sections) and any relevant calculations (e.g., calculation of shale gouge ratio);
  - ✓ narrative that describes and integrates the relevant information, including a discussion of any spatial heterogeneity in sealing properties and whether a fault or fracture is likely to be transmissive in the project area; and
  - ✓ discussion of uncertainties in the data.

Detailed Geology & Hydrogeologic Site Characterization

Depth, Areal Extent , and Thickness of Injection & Confining Zones

- 40 CFR 146.82(a)(3)(iii) requires submittal of information on the depth, areal extent & thickness of the injection formation & confining zone(s)
- in illustrating this information, EPA suggests the following:
  - ✓ isopach maps
  - ✓ isochore maps supported by available well logs and cores
  - ✓ seismic or other geophysical survey results w/ relevant info highlighted
  - ✓ well log data, if available, w/ injection & confining zones highlighted
- narrative about required information including discussion of variability of thickness of injection formation & confining zone(s) ; data quality & uncertainties.

Detailed Geology & Hydrogeologic Site Characterization

Petrology & Mineralogy of Injection & Confining Zones

- 40 CFR 146.82(a)(3)(iii) requires submittal of data on mineralogy of injection & confining zone(s).
- supports identification of any geochemical reactions that may affect storage and containment of injected carbon dioxide which could result from potential changes in properties of injection or confining zones (e.g., porosity, permeability, injectivity).
- provides information on mobilization of trace elements from formation matrix if minerals known to contain trace elements are identified, which informs decisions regarding parameters to analyze as part of a testing and monitoring program.

Detailed Geology & Hydrogeologic Site Characterization

Petrology & Mineralogy of Injection & Confining Zones (cont.)

- evaluation of minerals and potential geochemical reactions is the basis of the required demonstration of compatibility of the carbon dioxide stream with fluids in the injection zone and minerals in the injection and confining zones required prior to commencement of injection
- if evaluation of potential geochemical processes suggests long-term storage and confinement of carbon dioxide may be affected by changes in the injection formation and confining zone(s), the AoR delineation may need to account for geochemical reactions through the use of reactive transport models

Detailed Geology & Hydrogeologic Site Characterization

Petrology & Mineralogy of Injection & Confining Zones (cont.)

- any potential effects on storage and confinement due to mechanisms such as precipitation and dissolution may also affect the post-injection site care (PISC) time frame.
- data collection & analysis
  - ✓ existing data within AoR? sufficient quality & completeness?
  - ✓ discuss possible need for stratigraphic test well with UIC Director
  - ✓ basic lithology from mud logging & cores; polarized light microscopy, SEM, powder XRD

Detailed Geology & Hydrogeologic Site Characterization

Petrology & Mineralogy of Injection & Confining Zones (cont.)

- EPA recommends a narrative report that includes the following information:
  - ✓ methods used in examining samples;
  - ✓ locations (on maps) and depths of samples and the names of the formations sampled;
  - ✓ lithologies and descriptions (e.g., color, texture) from cores or hand samples;
  - ✓ mineralogic and petrologic descriptions obtained via microscopy (with approximate percentages of minerals);
  - ✓ cementation minerals and dissolution features; and
  - ✓ preliminary discussion of geochemical reactions that may affect the storage, confinement, and/or overall performance of the project.

Detailed Geology & Hydrogeologic Site Characterization

Porosity, Permeability, & Capillary Pressure of Injection & Confining Zones

- 40 CFR 146.82(a)(3)(iii) requires submittal of data on porosity, permeability & capillary pressure of injection & confining zones
  - ✓ crucial for a number of aspects of site characterization including determination of storage capacity, injectivity, & integrity of confining zone
  - ✓ also needed for multiphase modeling to predict plume & pressure front behavior & to delineate AoR.

Detailed Geology & Hydrogeologic Site Characterization

Geomechanical Characterization

- 40 CFR 146.82(a)(3)(iv) requires that geomechanical information be submitted on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone.
- geomechanical characterization is important for evaluating confining zone integrity as well as setting safe operational parameters
- information to provide:
  - ✓ test(s) performed, dates, and locations (on maps);
  - ✓ sample collection procedures for cores;
  - ✓ test conditions (as appropriate);
  - ✓ results in tabular and/or graphical form;

Detailed Geology & Hydrogeologic Site Characterization

Geomechanical Characterization (cont.)

- ✓ narrative of test results, including any anomalies or uncertainties in the data;
- ✓ comparison of data from different tests if more than one type of test is used for a particular parameter; and
- ✓ any issues with sample procurement, e.g., disintegration of poor quality rocks during transport or sample retrieval, the existence of discontinuities (fractures, fossils, etc.) in tested samples.

Detailed Geology & Hydrogeologic Site Characterization

Seismic History

- 40 CFR 146.82(a)(3)(v) requires a report on the seismic history of the project site, including the presence and depth of all seismic sources
- information to submit:
  - ✓ tabulation and/or map of seismic sources and their depths;
  - ✓ tabulation of seismic events, their hypocenters, and magnitudes for as far back as data are available;
  - ✓ sources of all seismic history data;
  - ✓ information on any seismic risk models used and the results; and
  - ✓ discussion of the degree of seismic risk in the region and information to support a determination that the confining system and wells at the project site are not vulnerable to damage from seismic activity.

Detailed Geology & Hydrogeologic Site Characterization

Hydrology & Hydrogeology of AoR

- 40 CFR 146.82(a)(5) requires submission of maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells, and springs within the AoR, their positions relative to the injection zone(s) and confining zone(s), and the direction of water movement, where known
- to meet this requirement, EPA recommends the following information:
  - ✓ numbers, thicknesses, and lithologies of USDWs (including interbedded low permeability zones);
  - ✓ information on all USDWs in the AoR and the region, and whether they are currently being used for drinking water; and
  - ✓ location of water wells and springs within the AoR.

Detailed Geology & Hydrogeologic Site Characterization

Baseline Geochemical Characterization

- 40 CFR 146.82(a)(6) requires baseline geochemical information on subsurface formations including all USDWs in the AoR including both fluid and solid phase chemical analysis.
  - ✓ information on water chemistry indicates which formations in the stratigraphic column qualify as USDWs and confirms that the proposed injection formation is not a USDW.
  - ✓ geochemical information on both solids and fluids is also needed, in combination with the mineralogic data required at 40 CFR 146.82(a)(3)(iii), to determine whether the interaction of the formation fluids with the injectate and solids will cause changes in injectivity, changes in the properties of the confining zone, or the release of trace elements.

Detailed Geology & Hydrogeologic Site Characterization

Geophysical Characterization

- the guidance discusses the use of geophysical methods for obtaining subsurface information in lieu of direct physical sampling. These methods include:
  - ✓ Seismic Methods – 2D, 3D, Vertical Seismic Profile (VSP), 3D-VSP, Cross-well, Borehole Microseismic
  - ✓ Gravity Methods – Aerial & Surface Gravity, Borehole Gravity
  - ✓ Electrical / Electromagnetic Geophysical Methods – Natural Source, Controlled Source, Electrical Resistance Tomography (ERT)
  - ✓ Magnetic Methods – Aerial & Surface Magnetic

Detailed Geology & Hydrogeologic Site Characterization

Surface Air & Soil Gas Monitoring

- 40 CFR 146.90(h) – at the discretion of the UIC Program Director, monitoring of surface air and/or soil gas for CO_2 leakage may be required.
  - ✓ Baseline surface air and soil gas data should be collected if the UIC Program Director requires surface air and soil gas monitoring as part of the Testing and Monitoring Plan.
  - ✓ in the guidance, EPA makes recommendations regarding the selection of monitoring parameters and the location of monitoring sites
  - ✓ Further information on technologies that can be used for soil gas and surface air monitoring can be found in the *UIC Program Class VI Well Testing and Monitoring Guidance* and the *Subpart RR General Technical Support Document for Injection and Geologic Sequestration of Carbon Dioxide (USEPA, 2010)*.

Demonstration of Site Suitability

The information required at 40 CFR 146.82 and described in this guidance provide comprehensive data and descriptions for many properties of the proposed project site (e.g., porosity, geochemistry).

These data do not individually provide a complete picture of the site to demonstrate that it can safely receive and confine the carbon dioxide.

Together, however, this information can form a comprehensive picture of the site and demonstrate whether it is a good candidate for GS and meets the requirements at 40 CFR 146.83.

This section describes how the owner or operator can synthesize the information collected during site characterization to demonstrate site suitability.

Demonstration of Site Suitability

- Facies Analysis for Project Site
- Structure of Injection & Confining Zones
- Compatibility of CO_2 Stream w/ Subsurface & Well Materials
- Demonstration of Storage Capacity
- Demonstration of Confining Zone Integrity
- Considerations for Secondary Confinement
- Reporting Process

Facies Analysis for Project Site

- 40 CFR 146.82(a)(3)(iii) requires owners or operators to provide information on facies changes in the injection and confining zones.
- prepare narrative of the inferred depositional environment(s) at the project site in the context of the site geologic conceptual model; narrative should reference appropriate data, maps, geophysical images, cross sections, and stratigraphic columns and should address, at a minimum:
  - implications for connectivity within the injection formation and the suitability of the confining zone;
  - lithofacies distributions mapped in the injection and confining formations, including the distributions of properties such as porosity and permeability for each lithofacies;
  - potential for preferential flow paths;
  - diagenetic processes that may affect present-day hydrogeologic properties; and
  - uncertainties associated with the data and with the resulting facies model.

Structure of Injection & Confining Zones

- 40 CFR 146.82(a)(3)(vi) requires that geologic and topographic maps and cross sections illustrate the geologic structure of the local area.
- prepare narrative that clearly describes how the local and regional geologic structure are conducive to GS and that an adequate confining system is present. The narrative should:
  - describe how the structure of the injection and confining zones fit into and support the development of the site conceptual model developed for delineation of the AoR.
  - identify which features support the capacity of the site to contain carbon dioxide, including the role of structural traps.
  - address potential weaknesses (e.g., if faults are present, whether data indicate that they are sealing).
  - discuss whether there are alternative interpretations to the data.

Compatibility of CO_2 Stream with Subsurface & Well Materials

- 40 CFR 146.82(c)(3) requires a report demonstrating the compatibility of the carbon dioxide stream with fluids in the injection zone(s) and minerals in both the injection and the confining zone(s), based on the results of the formation testing program, and with the materials used to construct the well; needed to support an understanding of the following:
  1) whether subsurface interactions among the injectate, fluids, and solids will lead to precipitation or dissolution of minerals such that permeability, porosity, and injectivity may change;
  2) if geochemical changes due to the introduction of large amounts of carbon dioxide into the subsurface might cause trace elements such as lead or arsenic to be liberated from subsurface solids; and
  3) if interactions among the fluid, carbon dioxide, and cement might cause deterioration of the cement such that the cement sheath would become a conduit for fluid migration.

Compatibility of CO_2 Stream with Subsurface & Well Materials (cont.)

- Demonstration of Compatibility of the Carbon Dioxide Stream with Fluids and Minerals will use information gathered during site characterization and during execution of formation testing program, including:
  - chemical analyses of fluids in the injection zone and, if available, the confining zone;
  - mineralogy of the injection and confining zones;
  - bulk chemical analyses of solids in the injection and confining zones;
  - pressure, temperature, and pH in the injection zone and, if available, the confining zone; and
  - chemical characteristics of the injectate .

Compatibility of CO2 Stream with Subsurface & Well Materials (cont.)

- Demonstration of Compatibility with Well Materials showing that reactions between the cement, formation fluids, and carbon dioxide will not lead to deterioration in the strength of the cement sheath or increases in the porosity and permeability that could result in the cement sheath becoming a conduit for carbon dioxide or carbon dioxide-rich fluids. Information gathered during site characterization and during well construction will be used, including :
  - chemical analyses of fluids in the injection zone and, if available, the confining zone;
  - cement type and additives;
  - pressure, temperature, and pH in the injection zone and, if available, the confining zone;
  - chemical characteristics of the injectate, including impurities that may result in an especially low pH (e.g., sulfur dioxide); and
  - mineralogy of the injection and confining zones.

Demonstration of Storage Capacity

- 40 CFR 146.83(a)(1) requires a demonstration that the geologic system is comprised of an injection zone(s) of sufficient areal extent, thickness, porosity and permeability to receive the total anticipated volume of the carbon dioxide stream.
- the guidance discusses the geologic and project-specific (e.g. injection well configuration, CO_2 stream composition, etc.) characteristics that influence the estimation of storage capacity
- the guidance also discusses static and dynamic models and how they are used to make estimations of carbon dioxide storage capacity.

Demonstration of Storage Capacity (cont.)

- In reporting storage capacity estimates, the owner or operator should submit:
  - description of the selected estimation method, including a discussion of its suitability for the type of formation;
  - tabulation of any input data used, along with estimates of uncertainty in those data;
  - results in tabular or graphic format;
  - discussion of the results, relating them to proposed operational parameters and the anticipated total volume of carbon dioxide to be injected and the duration of the project and any identified site-specific vulnerabilities (e.g., faults, fractures, etc.);
  - discussion of assumptions and limitations of the method used;
  - discussion of uncertainty based on the results of a sensitivity analysis; and
  - discussion of how the results are consistent with and/or supported by the AoR delineation modeling.

Demonstration of Confining Zone Integrity

- 40 CFR 146.83(a)(2) requires a demonstration that the geologic system is comprised of confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).
- confining zone(s) may not allow migration of carbon dioxide, either through interconnected pore spaces across the thickness of the seal or through the confining zone along faults or fractures. In particular, analyses may be needed to ensure that existing non-transmissive faults will not become transmissive under anticipated injection and storage pressures.

Demonstration of Confining Zone Integrity (cont.)

- to demonstrate competence of confining zone(s), synthesis of several types of data gathered through the site characterization process will be required. examples of such data are:
  - **Lithologic and stratigraphic data**, e.g., on the depth, thickness, and mineralogy of the confining zone;
  - **Structural data**, e.g., on faults and fractures, including fault geometry, depth of origin and termination, and the amount of displacement along the fault, including determinations of whether slip is consistent or variable along the fault and where such variations occur;
  - **Data from core analysis**, e.g., the capillary pressure, rock strength, permeability, and porosity;
  - **Field formation testing data**, e.g., in situ fluid pressures, the magnitudes of principal stresses, and temperature ; and
  - **Geophysical survey data**, e.g., seismic, gravity, magnetic, or other geophysical methods

Demonstration of Confining Zone Integrity (cont.)

- the guidance discusses movement of carbon dioxide through a continuous confining zone lacking faults or fractures in terms of capillary pressure and permeability
- the guidance discusses transmission of carbon dioxide through faults which can be generated when capillary entry pressure and pore pressure exceed the rock strength
- the guidance discusses the characterization of the sealing potential of existing faults and fractures in terms of juxtaposition of units, cataclasis (misspelled as 'catalysis' in the guidance), diagenetic sealing, calculation of shale gouge ratio (SGR), and pressure compartmentalization
- special considerations for characterizing lower confining zones are discussed for those applying for an injection depth waiver.

Considerations for Secondary Confinement

- 40 CFR 146.83(b) provides the UIC Program Director with discretion to require identification and characterization of additional confining zones if:
  - primary confining zone does not exhibit sufficient strength to allow injection at the proposed pressures;
  - known or suspected faults or fractures transect the primary confining zone and would interfere with containment of carbon dioxide;
  - primary confining zone is not sufficiently extensive to cover the entire maximum extent of the carbon dioxide plume and pressure front or it is not sufficiently thick and homogeneous over the entire area; or
  - insufficient information or conflicting data about the primary confining zone.

Reporting Process

- 40 CFR 146.82(a) and (c) requires submittal of site characterization data with permit application or prior to receiving authorization to begin injection, respectively.
  - submitted in electronic format approved by EPA
  - data and supporting documents - submitted as PDF files, including charts, graphs, and tabular data.
  - raw data - submitted in separate files (e.g., LAS, Excel).
  - maps - submitted in a GIS-compatible format.
  - for additional information on complying with reporting requirements, see the *UIC Program Class VI Well Recordkeeping, Reporting, and Data Management Guidance for Owners and Operators.*

Prior to Injection

- 40 CFR 146.82(c) requires submittal of extensive geologic and hydrogeologic data collected during the construction of a Class VI well to demonstrate that the injection and confining zones are suitable for receiving and containing the injected fluids
- This section of the guidance focuses on the formation and well testing and logging activities that the owner or operator must conduct to generate the information and data required to receive authorization to inject at a Class VI well.

Prior to Injection

- Well Logging
- Core Analyses
- Characterization of Injection Formation Fluid Chemical & Physical Properties & Downhole Conditions
- Fracture Pressure of Injection & Confining Zones
- Hydrogeologic Testing

Well Logging

- 40 CFR 146.87 requires that, during the drilling and construction of a Class VI injection well, the owner / operator must run logs, conduct surveys, and perform tests when appropriate to determine or verify the depth, thickness, porosity, permeability, lithology, and salinity of any formation fluids in all relevant geologic formations.
- The *UIC Program Class VI Well Construction Guidance* provides information on how owners / operators can meet the injection well testing requirements.
- These post-well construction / pre-operational testing and logging data will provide updates to and can be synthesized with related injection and confining formation data obtained during the GS site characterization and submitted earlier as part of the Class VI permit application.

Well Logging (cont.)

- at a minimum, well logs must include resistivity, spontaneous potential, gamma ray, porosity, fracture finder logs, and any other logs the UIC Program Director requires based on the geology of the site. These logs must be conducted before installation of the surface casing and before installation of the long-string casing. Any alternative methods that provide equivalent or better information must be approved by the UIC Program Director prior to implementation.
- the guidance describes the information that must be submitted in fulfilling the well logging requirement

Core Analyses

- 40 CFR 146.87(b) requires the owner / operator to take whole cores or sidewall cores of the injection and confining zones and formation fluid samples from the injection zone(s) and to submit to the UIC Program Director a detailed report prepared by a log analyst.
- the guidance discusses the nature of the core sampling and the information that should be included in the core logs: lithology, thickness, grain size, sedimentary structures, diagenetic features, contacts, textural maturity, oil staining, fracturing, and porosity.
- laboratory analysis of cores should include petrology and mineralogy; petrophysical properties; and geomechanical properties
- the guidance discusses special core analysis (SCAL) to obtain an in-depth suite of tests for parameters relevant to GS, such as relative permeability, capillary pressure, fluid compatibility, wettability, and pore volume compressibility.

Characterization of Injection Formation Fluid Chemical & Physical Properties & Downhole Conditions

- 40 CFR 146.82(a)(8) and 146.87(b) require the sampling and characterization of the chemical and physical properties of the formation fluids in the injection zone.
- 40 CFR 146.87(c) requires the recording of the fluid temperature, pH, specific conductivity (SC), reservoir pressure, and static fluid level
- the guidance discusses methods for collecting required data
- see the *UIC Program Class VI Well Testing and Monitoring Guidance* for additional information

Fracture Pressure of Injection & Confining Zones

- 40 CFR 146.87(d)(1)] requires owners or operators to determine or calculate the fracture pressure of the injection and confining zones
- the guidance discusses the common method for obtaining the required information – step rate test – and recommended test set up (EPA Region 8 Step-Rate Test Procedure).

Hydrogeologic Testing

- 40 CFR 146.87(e)(1)–(3) requires verification of the hydrogeologic characteristics of the injection zone(s) by performing a pressure fall-off test and either a pump test or an injectivity test.
- the guidance discusses the recommended test procedures (EPA Region 6 'The Nuts and Bolts of Falloff Testing') and how these tests are used to determine the transmissibility of the reservoir, the skin factor, and to identify nearby faults or fractures

Rocky Mountain CarbonSAFE Phase I

Appendix O

Stakeholders

	Organization	Contact Name	Potential Benefits	Potential Concerns	Email	Phone	Postal Address	Website	Notes
Officials/Government Agencies	USTAR	Andrew Sweeney	Economic stability. As market forces and legislation require decreased carbon emmisions, the project may provide	Increased electrical rates could slow economic growth.	asweeney@utah.gov		60 E. South Temple, Third Floor, Salt Lake City, UT 84111	https://ustar.org/	Utah Science Technology and Research Initiative. "leverage science and technology innovation to expand and diversify the State's economy"
	Utah's Governor's Office of Energy Development	Alair Emory	The project falls under the offices purview to facilitating the development of the Utah's diverse energy sector.	Environmental issues.	alairemory@utah.gov	801-538-8722	P.O. Box 144845, Salt Lake City, UT 84114	http://energy.utah.gov/	
	CoalBlue	Jonathan Wood	Energy production with "clean, low-carbon coal."		jwood@coalblue.org	410-662-2130	1110 Vermont Ave, NW Suite 1000, Washington DC 20005	http://coalblue.org/	Group founded by Democrats to promote 'clean, low-carbon coal.'
	Sandia National Laboratories, Center for Experimental Geosciences	Charles Choens			rcchoen@sandia.gov		MS 0735, Sandia National Laboratories, 1515 Eubank SE, Albuquerque, NM, 87123		
	PRRC, New Mexico Tech / SWP	Martha Cather			martha@prrc.nmt.edu	575-835-6916	801 Leroy Place, Socorro, NM 87801	http://www.prrc.nmt.edu/	Petroleum Recovery Research Center, Industry Service & Outreach Group. Martha heads up the outreach component of the Southwest Regional Partnership on Carbon Sequestration.
	Emery County	Lynn Sitterud	Direct jobs. As market forces and legislation require decreased carbon emmisions, the project may provide economic stability by stabilizing the region's coal mines and power plants.	Increased consumer electrical rates. Increased power production costs resulting in non-competitive wholesale pricing. Induced seismicity.	lynns@emery.utah.gov	435-381-3570	P.O. Box 629, Castle Dale, UT 84513	http://www.emerycounty.com	Chairman - Lynn Sitterud Commissioners - Paul Cowley, Kent Wilson
	Castle Dale City Town Council		same as above	same as above	mayor@castledalecity.org	435-381-2115	P.O. Box 728, Castle Dale, UT 84513	http://www.getdirtywithus.org	Mayor - Danny VanWagoner City Council - Bradley Giles, Joel Dorsch, Doug Weaver, Jacob Barnett, Julie Johansen
	Orangeville City		same as above	same as above	orange@etv.net	435-748-2651	P.O. Box 677, Orangeville, UT 84537	http://www.ovcity.info	Mayor Roger Swenson City Council- Carol Stilson, Carole Larsen, Brandon Hoffman, Janet Tuttle, Kirk McQuivey
	The Seven County Infrastructure Coalition	Mike McKee Executive Director			mmckee@7county.utah.gov	435-823-5010	5995 S. Redwood Road Salt Lake City, UT 84123	http://scic-utah.org	The Coalition includes Carbon, Daggett, Duchesne, Emery, San Juan, Sevier, and Uintah Countys. Its main role is to identify revenue-producing infrastructure assets benefiting the region. Its mission is to plan infrastructure corridors, procure funding, permit, design, secure rights-of-way and own such facilities.
	UT House of Representatives R-Bountiful	Rep. Raymond Ward	Reducing atmospheric CO2 will address climate change.		rayward@le.utah.gov	801-440-8765	954 E. MILLBROOK WAY, BOUNTIFUL, UT, 84010	http://house.utah.gov/rep/WARDR	2018, Sponsored H.C.R. 1, Concurrent Resolution on Climate Change, which acknowledges climate change and "states that the Legislature and Governor will continue to base decisions regarding state energy policies on the best scientific evidence available..."
	UT House of Representatives R-North Salt Lake	Rep. Rebecca Edwards	Reducing atmospheric CO2 will address climate change.		beckyedwards@le.utah.gov	801-554-1968	1121 EAGLEWOOD LOOP, NORTH SALT LAKE, UT, 84054	http://house.utah.gov/rep/EDWARRP	2018, Sponsored H.C.R. 7, Concurrent Resolution on Economic and Enviornmental Stewardship, which "recognizes the impacts of a changing climate on Utah citizens; expresses commitment to create and support economically viable and broadly supported solutions, including in rural communities..."
		Robert Finley			finelygeology@gmail.com	217-649-1744			Formerly with the IL Geological Survey, where he went through, as part of the FutureGen project, everything you now face with CarbonSAFE. He can speak authoritatively about the safety of CCS (for a project done right). Believe he could be very helpful in addressing, and hopefully calming, concerns/fears about leakage and contamination.
Environmental health directors from the local health departments around the state				Worker health and safety. Any local environmental impacts from infrastructure. Induced seismicity.				https://deq.utah.gov/Topics/Resources/healthdptsdw.htm	Suggested by Candice Cady.
	Bear River Health Department	Grant Koford		same as above	gkoford@brhd.org	435-792-6575	85 East 1800 North, Logan, Utah 84341	http://www.brhd.org/	
	Central Utah Public Health	Nathan Selin		same as above	nselin@utah.gov	435-896-5451 ext 342	70 Westview Dr., Richfield, Utah, 84701	http://www.centralutahpublichealth.com/index.html	
	Davis County Health Dept.	Dennis Keith		same as above	dkeith@daviscountyutah.gov	801-525-5100	Davis County Health Department, Environmental	http://www.daviscountyutah.gov/health/about-	
	Salt Lake Valley Health Dept.	Royal DeLegge		same as above	rdelegge@slco.org	385-468-3860	788 East Woodoak Lane (5380 South), Murray, UT 84117	http://slco.org/health/	
	San Juan Health	Rick Meyer		same as above	rmeyer@sanjuancounty.org	435-678-2723 ext. 1005	196 East Center Street, Blanding UT 84511	http://www.sanjuanpublichealth.org/index.html	
	Southeastern Utah District Health Dept.	Brady Bradford		same as above	bbradfor@utah.gov	435-637-3671	28 South 100 East, Price UT 84501	https://www.seuhealth.com/program	
	Southwest Utah Public Health Dept	Gary House		same as above	ghouse@swuhealth.org	435-673-3528	620 South 400 East, Suite 400, St. George, UT 84770	https://swuhealth.org/southwest-utah-environmental-health/	
	Summit County Health Dept	Phil Bondurant		same as above	pbondurant@summitcounty.org	435-333-1584	650 Round Valley Drive, Park City, Utah 84060	http://summitcountyhealth.org/environmental-health/	
	Tooele County Health Dept.	Wade Tolebert		same as above	wtolbert@tooelehealth.org	435-277-2440	151 N. Main Street, Tooele, UT 84074	http://tooelehealth.org/environmental-health/	
	TriCounty Health Department	Darrin Brown		same as above	dbrown@tricountyhealth.com	435-247-1163	133 South 500 East Vernal, Ut 84078	https://tricountyhealth.com/environmental-health/	
	Utah County Health Dept.	Bryce Larsen		same as above	brycel@utahcounty.gov	801-851-7525	151 S. University Ave., Provo, UT 84601	http://www.utahcountyonline.org/Dept2/Health/Environmental%20Health/home.asp	
	Wasatch County Health Dept.	Dwight Hill		same as above	dhill@wasatch.utah.gov	435-657-3261	55 South 500 East Heber City, Utah 84032	http://www.wasatchcountyhd.org/Programs/EnvironmentalHealth.aspx	
	Weber County Health Dept.	Michela Gladwell		same as above	mgladwell@co.weber.ut.us	801-399-7160	477 23rd Street, Ogden, UT 84401	http://www.webermorganhealth.org/environmental-health-services/	
Regulators	Utah Division of Oil, Gas and Mining	John Baza			johnbaza@utah.gov	801-5385340	1594 W North Temple, Suite 1210, Salt Lake City, UT 84116	https://www.ogm.utah.gov	Director- John Baza
Business Interests	PacifiCorp	Ian Andrews	Public acceptance of continued use of coal-fired power plants. Future legislation may mandate some sort of CO2 capture	Infrastructure and opperating costs. Decreased capacity.	Ian.Andrews@PacifiCorp.com	888-221-7070	1407 West North Temple, Ste 310, SLC, UT 84116		
	PacifiCorp (Hunter)	Larry Bruno			Larry.Bruno@pacificorp.com	435-748-5114	UT-10, Castle Dale, UT 84513		

	PacifiCorp (Hunter)	Quinn Healy			Quinn.Healy@pacificorp.com	435-748-5114	UT-10, Castle Dale, UT 84513		
	HBW Resources	Andrew Browning			abrowning@hbwresources.com	713-337-8810	2211 Norfolk Street #410, Houston, TX 77098	https://hbwresources.com/	Energy industry consultant
	Schlumberger outreach	Wayne Rowe			rowe5@slb.com	303-594-1219	1875 Lawrence St. Ste. 500, Denver, CO 80202	https://hbwresources.com/	Western U.S. Program Manager for Schlumberger Carbon Services
Locals/ Interested Citizens		Paul Anderson	via email- Project would help reduce CO2 emissions and bring jobs.	via email: long-term leakage, who bears costs of construction and operation? Concerns addressed via email reply.	paul@pbageo.com	801-364-6613	PO Box 101, Emery, UT 84522		Consulting geologist. Ferron specialist. Involved with many UGS projects.
		Mary Ann Wright			MAW@pbageo.com	801-502-9611	PO Box 101, Emery, UT 84522		Retired Utah Division of Oil, Gas and Mining
		Ken Fleck			Ken.Fleck@pacificorp.com	435-650-0386	280 N 1280 W, Price, UT 84501		UGS Board member / Geology and Environmental Affairs Manager PacifiCorp - Interwest Mining Company
		Pete Kilbourne			pkgeog@gmail.com	435-650-8041	140 Hillcrest Dr Price, UT 84501		UGS Board member / PKGeography LLC
Environmental Groups (local/regional)	Southern Utah Wilderness Alliance	Karin Duncker Associate Director	Reducing atmospheric CO2 will address climate change.	Any impacts to "wilderness	karin@suwa.org	801-428-3971	425 E 100 S, SLC, UT 84111	https://suwa.org/	"...defend America's redrock wilderness from oil and gas development, unnecessary road construction, rampant off-road vehicle use, and other threats to Utah's wilderness-quality lands.
	Western Resource Advocates	Joro Walker	same as above	Air quality degradation due to continued coal-fired powerplant operation. Any potential impacts to sage grouse habitat. Any potential impacts to San Rafael Swell	joro.walker@westernresources.org	801-413-7353	150 South 600 East, Suite 2A, SLC, UT 84102	http://westernresourceadvocates.org/regions/utah/	likely concerned about coal, sage grouse, and the Swell
	Wild Utah Project	Allison Jones	same as above	Any potential impacts to sage grouse, wildlife habitat connectivity, or endemic plants	info@wildutahproject.org	801-328-3550	824 S 400 W, Suite B117, SLC, UT 84101	https://www.wildutahproject.org/	likely concerned about sage grouse, wildlife habitat connectivity, and endemic plants
	Sierra Club of Utah	Mark Clemens	Reducing atmospheric CO2 will address climate change. (The Sierra Club Foundation's Forward Fund supports "Identifying and supporting new opportunities to bring ecologically sound carbon capture and sequestration processes to scale.")	Any potential impacts to sage grouse habitat. Concerns about continued reliance on coal.	mark.clemens@sierraclub.org	801-467-9294	423 West 800 South, Ste A103, SLC, UT 84101-223	http://utah.sierraclub.org/	likely concerned about coal and sage grouse
	National Parks Conservation Association	Britte Kirsch Regional Coordinator	Reducing atmospheric CO2 will address climate change.	Regional air quality degradation due to continued coal-fired powerplant operation.	ekirsch@npca.org	801-521-0785	307 West 200 South, Ste. 5000, SLC, UT 84101	https://www.npca.org/regions/southwest	interested in coal fired power plant emissions and downwind air quality that could impact national parks
	Physicians for a Healthy Environment	Denni Cawley	same as above	Air quality degradation due to continued coal-fired powerplant operation.	dcawleyuphe@gmail.com	385-707-3677	423 W. 800 S., Suite A108, SLC, UT 84101	http://uphe.org/	possibly concerned about coal and indirect impacts to air quality
Environmental Groups (national)	Natural Resources Defense Council	George Peridas	Reducing atmospheric CO2 will address climate change.		gperidas@nrdc.org	415-875-6100	111 Sutter Street, 21st Floor, San Francisco, CA 94104	https://www.nrdc.org/	supports CCS
	National Audubon Society	David Yarnold, President	same as above	Any potential impacts to sage grouse habitat or other ground nesting birds	mhsiclait@audubon.org -executive assistant	212-979-3196	225 Varick St, 7th Fl. , NY, NY 10014		
	National Audubon Society	Heather Dove Great Salt Lake Chapter	same as above	Any potential impacts to sage grouse habitat or other ground nesting birds	president@greatsaltlakeaudubon.org	801-201-3637	PO Box 520867, SLC, UT 84152-0867	http://www.greatsaltlakeaudubon.org/about-us/directory	because of potential impacts to greater sage grouse
	Wilderness Society	Scott Miller	same as above	Any potential impacts to San Rafael Swell	Scott_Miller@tws.org	303-468-1961	1660 Wynkoop Street, Suite 850, Denver, CO 80202	http://wilderness.org/	interested in the Swell
	Teddy Roosevelt Conservation Partnership	Kevin Farron Western Field Associate	same as above	Any potential impacts to upland bird and big game habitat in the area	kfarron@trcp.org	406-926-3201	725 W. Alder St., Suite 1, Missoula, MT 59802	http://www.trcp.org/leadership/	upland bird and big game habitat in the area
	Sportsmen for Fish and Wildlife	Troy Justensen President	same as above	Any potential impacts to upland bird and big game habitat in the area	xtremeoutfitter@msn.com	801-557-3362	215 North Redwood Road #1, North Salt Lake, UT 84054	https://sfw.net/	upland bird and big game habitat in the area
Educators	Utah State University Eastern	Michelle Fleck	Post-secondary educational opportunities		michelle.fleck@usu.edu	435-613-5232	Utah State University Eastern 263 Reeves Building 451 East 400 North Price, Utah 84501	https://geology.usu.edu/people/faculty/index	
	Emery High School	Steven Gordon	High school educational opportunities		Steveng@emeryschools.org	435-381-2689	955 North Center St, P.O. Box 499, Castle Dale, UT 84513	http://ehs.emeryschools.org/About-Us/Meet-the-Faculty	Principal
	Emery High School	Lee Moss	High school science teaching opportunities		Moss@emeryschools.org	435-381-2689	955 North Center St, P.O. Box 499, Castle Dale, UT 84513	http://ehs.emeryschools.org/About-Us/Meet-the-Faculty	Chemistry and physics teaher

STEP Project Report

Period Ending: December 31, 2019

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 minimize coal consumption and the attendant emissions associated with reduced coal use. The study will focus on the application of parabolic solar troughs and will also consider power tower collections systems. The project is on schedule and began in February 2019.

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; and
- Land requirements.

Project Accounting:

Cost Object	2017	2018	2019	Total
Annual Collection (Budget)	$0.00	$0.00	$187,000	$187,000
Annual Spend (Capital)	$0.00	$0.00	$0.00	$0.00
Committed Funds	$0.00	$0.00	$0.00	$0.00
Uncommitted Funds	$0.00	$0.00	$0.00	$0.00
External OMAG Expenses	$0.00	$0.00	$83,057*	$83,057
Subtotal	$0.00	$0.00	$83,057	$83,057

*All OMAG expenses were paid to Brigham Young University for the completion of the milestones listed below.

Project Milestones:

Project Milestones	Delivery Date	Status
Contract between BYU and PacifiCorp complete	2/5/2019	Completed
Kickoff Meeting	2/12/2019	Completed
Report 1 to include literature review and representative model development	4/30/2019	Completed
Report 2, baseline plant model comparison to operational data	8/31/2019	Completed
Report 3, solar resource data, solar integration point, CSP characterization for modeling	12/31/2019	Completed
Report 4, preliminary estimates of fuel reduction, estimates for land use, capital cost, and impact on power generation	4/30/2020	On Target
Report 5, refine the plant model, parametric variations and optimization analyses	12/31/2020	On Target
Final report submitted, update and compilation of previous reports, and recommendation for implementation	12/31/2020	On Target

Program Benefits:

Thermal energy collected from a Concentrated Solar Power ("CSP") plant can be integrated into a traditional power plant (coal, natural gas, etc.) to offset the amount of fossil fuel required for heating. With CSP contributing to the heating load, less fuel is required, resulting in a decrease in fossil fuel cost and emissions. This study will address the viability of integrating CSP with coal-fired power plants including the Hunter Plant in Castle Dale, Utah. To aid in future evaluations, this study will include identifying a general plant model that can be used to determine hybrid feasibility and the optimization of solar integration into a general hybrid plant model. This statement of work outlines the milestones to be achieved during each period.

Potential future applications for similar projects: As we learn more about the technology, we will have a better understanding of potential future applications. It is possible that this technology could be deployed at several traditional power plants.

STEP Project Report

Period Ending December 31, 2019

STEP Project Name: Circuit Performance Meters (Substation Metering). COMPLETE.

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. The scope of the project involves setting up remote communication paths with all installed meters and the purchase of a data management and analytics tool to analyze, interpret and report on the collected data.

Project Accounting:

	2017	2018	2019	Total
Annual Collection (Budget)	$110,000	$550,000	$440,000	$1,100,000
Annual Spend (Capital)	$13,676	$427,349	$451,777	$892,802
External OMAG Expenses	$0	$0	$0	$0
Subtotal	$13,676	$427,349	$451,777	$892,802

Project Milestones:

Milestones	Delivery Date	Status/Progress
Complete two pilot sites in 2017	December 31, 2017	The two pilot sites were completed by December 31, 2017.
Execute contract for data analytics 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 twenty five circuits in 2018	December 31, 2018	Meter installations on twenty circuits were completed in 2018. All installed meters are operating and sending data to the Company's data collection system.

Install metering on 23 circuits in 2019	December 31, 2019	Meter installations on thirty four circuits were completed in 2019. All installed meters are operating and sending data to the Company's data collection system.

Program Benefits

- Enable increasing levels of distributed energy resources on the power grid by economically providing increased visibility on loading levels, load shape, and event information. Information gained will be used to develop interconnection studies and hosting capacities for customers while determining safe switching procedures and cost effective capital improvement plans.
- Assist 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 increased 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 distributed generation interconnection customer approval delays.
- 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. The Company is also looking into the possibility of integrating the smart meter with remote terminal units. Results of this investigation will be made in the final report that is on track to be complete by the end of 2020.

STEP Project Report

Period Ending December 31, 2019

STEP Project Name: Commercial Line Extension Pilot Program

Project Objective:

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

Project Accounting:

Table 1 gives the budgeted amounts through 2019. Funds are considered committed when the Company has determined the qualifying job costs and the STEP incentive amount. This is the Approved Date in **Table 3**. When funds are transferred into the job they are included in the Annual Spend (Capital). These correspond to the Paid items in the Status column in **Table 3**.

Table 1				
	2017	**2018**	**2019**	**Total**
Annual Collection (Budget)	$500,000	$500,000	$500,000	$1,500,000
Annual Spend (Capital)*	$0.00	$69,340	$81,743	$151,083
Committed Funds	$0.00	$11,682	$94,265	$105,947
Uncommitted Funds	$0.00	$0.00	$0.00	$0.00
External OMAG Expenses	$0.00	$0.00	$0.00	$0.00
Subtotal	$0.00	$81,022	$176,008	$257,030

*The annual spend figures correlate to the numbers shown on the accounting information provided on page 1.0.

Applications Received:

The request for primary voltage facilities also serves as the application for the Commercial Line Extension Pilot Program. When a line extension work request is received, the Company meets with the applicant and determines the nature of the project. The Company receives a wide range of line extension requests. For a request to qualify for the commercial line extension pilot program, the project must include installation of backbone infrastructure, and also not have enough electric service revenue allowances to cover the cost of that backbone. None of the developments receiving STEP funds are additional phases of the same development that had previously received STEP funds under a different phase.

Applications – Table 2				
	2017	2018	2019	Total
Applications Received	2	12	10	24
Applications Approved	2	12	10	24
Recipients Receiving Multiple Rewards	0	0	0	0

Table 3 – Individual Project Details:

In Docket No. 16-035-36, the Commission issued an order on February 6, 2019 approving the Company's request to increase the per-project incentive payment limit to $250,000 from the previously approved amount of $50,000. The intention of this change was to incentivize larger projects that could benefit from the funds to participate in the program. The total program budget is $2.5 million over the five-year pilot program period.

As of December 31, 2019, all developments receiving STEP funds were still under construction. At the time of this report no PV charging stations have been installed. Some developments only include road and utility infrastructure. These developments have no buildings or parking established by the initial developer. No charging station locations have been established at developments without buildings or parking

Other developments have plans for specific business or buildings as part of the initial development. For those developments where parking is established, charging station locations have been established as defined by the the STEP program.

Individual Project Details – Table 3									
	Status (paid or committed)	Approved Date	Gross Project Cost	Internal Backbone Cost	STEP 20% Incentive	Number of lots in Develop-ment	Parking installed (Y or N)	Number of charging locations (Conduit Extensions)	Number of individual PV charging stations
1	Paid in 2018	7/7/2017	$ 38,253	$ 36,611	$ 7,322	7	Y	1	TBD
2	Paid in 2018	9/18/2017	$ 40,069	$ 37,606	$ 7,521	5	N	--	--
				2017 Total	**$ 14,843**				
3	Paid in 2018	1/16/2018	$ 43,685	$ 39,783	$ 7,957	7	Y	1	TBD
4	Paid in 2018	3/14/2018	$ 102,804	$ 102,670	$ 20,534	7	Y	1	TBD
5	Paid in 2019	3/19/2018	$ 80,183	$ 80,183	$ 16,037	9	N	--	--
6	Paid in 2019	3/20/2018	$ 102,360	$ 100,714	$ 20,143	3	Y	1	TBD
7	Paid in 2019	3/29/2018	$ 25,141	$ 24,218	$ 4,844	5	Y	1	TBD

8	Paid in 2019	5/29/2018	$ 68,720	$ 30,669	$ 6,134	6	N	--	--
9	Paid in 2019	7/13/2018	$ 30,957	$ 29,315	$ 5,863	4	Y	2	TBD
10	Committed	7/26/2018	$ 58,410	$ 58,410	$ 11,682	1	Y	1	TBD
11	Paid in 2019	11/1/2018	$ 52,789	$ 13,035	$ 2,607	5	N	--	--
12	Paid in 2019	11/7/2018	$ 37,081	$ 33,803	$ 6,761	6	N	--	--
13	Paid in 2019	11/12/2018	$ 19,192	$ 19,192	$ 3,838	8	Y	1	TBD
14	Paid in 2019	12/6/2018	$ 248,411	$ 118,107	$ 23,621	1	N	--	--
				2018 Total	**$ 130,020**				
15	Committed	2/6/2019	$ 51,316	$ 48,038	$ 9,608	6	N	--	--
16	Committed	3/4/2019	$ 28,080	$ 22,827	$ 4,565	8	N	--	--
17	Paid in 2019	3/8/2019	$ 12,246	$ 11,794	$ 2,359	5	Y	1	TBD
18	Committed	4/10/2019	$ 56,807	$ 51,889	$ 10,378	8	N	--	--
19	Committed	4/10/2019	$ 57,078	$ 52,160	$ 10,432	8	Y	1	TBD
20	Paid in 2019	4/11/2019	$ 111,259	$ 77,709	$ 15,542	9	N	--	--
21	Committed	5/29/2019	$ 209,393	$ 133,897	$ 26,779	10	N	--	--
22	Committed	10/4/2019	$ 36,628	$ 34,160	$ 6,832	5	N	--	--
23	Committed	10/9/2019	$ 81,901	$ 77,787	$ 15,557	10	Y	1	TBD
24	Committed	11/6/2019	$ 50,570	$ 50,570	$ 10,114	4	N	--	--
				2019 Total	**$ 112,166**				

Project Milestones:

The Commercial Line Extension Pilot Program review is applied each time a commercial or industrial developer requests installation of primary voltage backbone facilities within their development. Each development is independent, and is evaluated when the developer makes the request for service. Funds are transferred to the individual job upon the developer paying its share of the cost of the development.

Key Challenges, Findings, Results and Lessons Learned:

The Commercial Line Extension Program was designed to encourage developers to install a full electrical backbone within their developments. This allows the Company to better engineer the electrical grid serving the area, leading to cost savings, greater reliability, and fewer future upgrade investments.

To the extent developers build within their developments, sites for PV charging will be identified and power made available to those locations. This will encourage adoption of EVs and contribute to the environmental benefits of EV use.

Potential future applications for similar projects:

This program will give the Company experience in incentivizing proper infrastructure planning to developers. This understanding will allow for more efficient upfront design of commercial and industrial developments and siting of electrical infrastructure supporting such areas.

STEP Project Report

Period Ending: December 31, 2019

STEP Project Name: Gadsby Emissions Curtailment

Project Objective:

To help improve air quality, the Gadsby Emissions Curtailment program allows the Gadsby Power Plant to 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, UDAQ 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, UDAQ 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	2018	2019	Total
Annual Collection (Budget)	$100,000	$100,000	$100,000	$300,000
Annual Spend	$0.00	$0.00	$7,067	$7,067
Committed Funds	$0.00	$0.00	$0.00	$0.00
Uncommitted Funds	$0.00	$0.00	$0.00	$0.00
External OMAG Expenses	$0.00	$0.00	$0.00	$0.00
Subtotal	$0.00	$0.00	$7,067	$7,067

On December 4 - 9, 2019, the Company curtailed Gadsby power plant due to UDAQ issuing a red advisory. The total calculated value of the curtailment over the time period was $7,067. The curtailment value is calculated by taking the difference between the on peak/off peak market price and the dispatch cost by unit. The difference is multiplied by the generation in MWh by unit. Confidential workpapers containing the calculation are included with this filing.

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 UDAQ (see Appendix 1), the Gadsby 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, 2019

STEP Project Name: Panguitch Solar and Storage Technology 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 12.47 kilovolt distribution circuits that are connected to the 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.

In Docket No. 16-035-36, the Commission approved the Company's request to increase funding for the Solar and Storage Technology Project by $1.75 million due to the response to the Company's Request for Proposals ("RFP"). Commercial operation commenced on March 3, 2020, but the Company awaits final completion from the EPC contractor.

Project Accounting:

	2017	2018	2019	Total
Annual Collection (Budget)	$500,000	$2,350,000	$5,900,000	$8,750,000
Annual Spend (Capital)*	$331,995	$75,474	$6,373,549	$6,781,019
Committed Funds	$0.00	$0.00	$0.00	$0.00
Uncommitted Funds	$0.00	$0.00	$0.00	$0.00
External OMAG Expenses	$0.00	$0.00	$0.00	$0.00
Subtotal	$331,995	$75,474	$6,373,549	$6,781,019

*The information provided includes funds charged to the STEP account and does not include funds from the Blue Sky program that were allocated to this project.

Project Milestones:

Milestones	Delivery Date	Status/Progress
Prairie Dog Permit	July 30, 2018	Complete
Small Generation Interconnection Agreement – Finalized	June 4, 2018	Complete

Award an engineering, procurement and construction (EPC) contract.	February 22, 2019	Complete
EPC Design Complete	August 1, 2019	Complete
EPC Major Equipment Delivered	September 3, 2019	Complete
Construction Complete	November 1, 2019	Complete
Commercial Operation Begins	March 9, 2020	Complete
Final Completion	December 31, 2020	On track

Key Challenges, Findings, Results and Lessons Learned:

Description of Investment	Anticipated Outcome	Challenges	Findings	Results	Lessons Learned
a. Enable Investment Tax Credit (ITC)	Utility will operate the solar and battery system to address system issues as well as capture ITC benefits	System not original designed for such capability	The battery and solar control architecture was not initially designed to accommodate ITC requirements	Control architecture changes were implemented on January 21, 2020	During design and setting of design criteria include ITC philosophy in specification and controls
b. Interconnection cost increases	N/A	Tight labor market for procurement of contractors (and wth required schedule); Nine poles required replacement from Panguitch Substation to the site	Contractor cost increases; Communication costs and labor higher than originally estimated	Passage of time also impacted estimates; in the end interconnection costs increased significantly	Detailed loading information and field inspection may be needed to accurately estimate interconnection costs.

c. Issues with fencing and grounding	Repaired in field	Issues with project construction quality	Multiple issues were identified that raised concerns regarding construction quality.	Fencing and grounding issues were corrected during the commission ing stage.	Establish clear fencing and grounding standards in the contract; conduct both design and field reviews during commissio ning
d. Consider providing temporary diesel generators for battery back-ups	More reliable and robust system	Cost of generators, permitting, and other ancillary electrical	Cost of generators, permitting, and other ancillary electrical	Not included; future project if justified	May not be required depending on future project location

Project Benefits

- The loading on the 69–12.47 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 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.
- Provides battery and solar training for Company personnel at both the office and field levels including the operation and maintenance on similar facilities and equipment.

Potential future applications for similar projects:

Depending on the outcome, there could be a number of applications across Rocky Mountain Power's system on long radial feeds similar to Panguitch. These applications would provide economic deferrals for major transmission rebuilds.

STEP Project Report
Period Ending December 31, 2019

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 demonstrate and understand the ability to integrate generation, energy storage, and controls to create a microgrid.

Project Accounting:

	2017	2018	2019	Total
Annual Collection (Budget)	$0.00	$70,000	$110,000	$180,000
Annual Spend (Capital)	$0.00	$90,713	$77,717	$168,430
Committed Funds	$0.00	$0.00	$0.00	$0.00
Internal OMAG Expenses	$0.00	$0.00	$0.00	$0.00
External OMAG Expenses	$0.00	$0.00	$0.00	$0.00
Subtotal	$0.00	$90,713	$77,717	$168,430

Project Milestones:

Milestones	Delivery Date	Status/Progress
Data collection and EVR characterization	06/30/2018	COMPLETE - Installed smart meter and started analyzing the EVR load profiles
Preliminary microgrid planning tool	09/30/2018	COMPLETE - Developed a linear programming-based planning tool to determine the size of energy storage.
Microgrid layout and test plan	12/31/2018	COMPLETE - Finalized layout of the EVR microgrid
Deploy microgrid system at EVR	04/30/2020	ONGOING - A Matlab based EMS is also under development and tuned with the load data that is being collected. Streamlining communication protocol of all microgrid components.

Optimize planning tool for microgrid	08/31/2019	COMPLETE
Apply planning tool to HAFB microgrid	12/31/2019	MILESTONE REMOVED
Create fact sheet for planning tool	4/30/2020	ONGOING – Authoring sheet to simplify explanation of planning tool and microgrid implementation with economic benefits.
Recommendations to DERs interconnection policy	06/30/2020	ONGOING – Reviewing current proposed redlines to policy 138 and generating additional recommendations.

Key Challenges, Findings, Results and Lessons Learned:

Description of Investment	Anticipated Outcome	Challenges	Findings	Results	Lessons Learned
a. Microgrid system operational at USU's EVR	Connect microgrid components to the central control system at the EVR for monitoring and control.	1. Establishing a connection interface for all components to get a complete view of the system. Commands from inverters are not the same across vendors. 2. Policy 138 requirement of a grounding transformer. 3. Transformer requirement to be located at point of interconnection of the solar array (policy 138), but the microgrid system required a neutral reference when disconnected from the grid. This requires a neutral reference be located at the service entrance and automatic transfer switch rather than at the solar array POI. 4. Grounding transformer needed to be increased in order to handle the neutral currents of the single-phase loads of the facility when islanded while also meeting the interconnection requirements. 5. Determining the allowable facility ampacity and	1. With revisions to policy 138 and transient overvoltage protection, the need for a grounding transformer for that feature was not required. 2. Plotting of the transformer not a concern. 3. The different system voltage needs of the facility, along with the ampacity usage, resulted in the widespread installation of solar inverters across the facility. 4. Communications for data collection and control of the inverters are vital for microgrid operation. 5. Much equipment is designed for conventional grid and must be revised for microgrid operation.	1. Data / Solar data to be available on EVR server for real-time viewing.	1. The grounding transformer was needed due to the battery inverter not able to establish a neutral reference for the facility when isolated. 2. Smart inverters that adhere to the IEEE 1547-2018 standard have TROV protection. This eliminates the need for grounding transformer TROV. 3. Try to establish the same types of communication protocols. 4. Market share for microgrid equipment is limited. 5. Protection relays are necessary for quick response to grid transients and fast control of equipment. 6. Natural gas generators are limited at the hundreds of kilowatts range. 7. In order to parallel a generator with the utility, the generator has to be prime power rated. This kind of rating is only

		ampere interrupt capacity of the EVR for DER interconnections. 6. Limited market share for microgrid equipment. 7. Designing for facility constraints.	6. Shortage on micro grid equipment in the hundreds of kilowatts range (i.e. automatic transfer switch and natural gas generator).		currently available at higher power levels (thousands of kilowatt levels). 8. Emergency standby generators are only available at the power levels the EVR is operating at.
b. Optimize planning tool for microgrid	Creation of planning tool for use in industry.	1. Quantifying real equipment prices as tool inputs	1. Many different technical, financial, and meteorological components have an effect on the design and economics of a microgrid	1. Optimized planning tool for various customers communica ted.	1. The design and financial benefits of a microgrid can be easily quantified, given accurate pricing, load, and weather data.
c. Create fact sheet for planning tool	Fact sheet to provide explanation for process to implement a microgrid and its benefits.	1. None currently identified.	1. Planning tool is simple to use and quantifies economic benefits of a microgrid to a customer	1. Clear fact sheet describing purpose of tool and value of results.	1. The microgrid planning tool can be applied to various customers to conceptually design a microgrid and detail its load-shaping and cost-saving capability.
d. Policy 138 review and proposed changes	Review of the interconnection policy, and identify areas for possible revision.	1. EVR facility has multiple inverters, policy 138 required a manual disconnect for each inverter within ten feet of the utility meter. Due to space limitations, the AC disconnects are not able to be located next to the meter. 2. Early challenge of grounding transformer for policy 138 compliance. 3. Transformer POI to the EVR facility was significant challenge. 4. Transformer requirement to be located at point of interconnection of the solar array (policy 138), but the microgrid system required a neutral reference when disconnected from the grid. This requires a neutral reference be located at the service entrance and automatic transfer switch rather than at the solar array POI.	1. Changes to policy 138 TROV protection, resulted in grounding transformer not needed. 2. Exceptions to AC disconnect locations can be granted on a per review basis. 3. Protection relays will help ensure that tripping times specified in the policy 138 are met.	1. Submission of proposed rule changes to policy 138.	1. Through software control, energy storage can be controlled similar to PV smart inverters. 2. SEL-751 protection relays have fast response to grid/facility transients. 3. Protection relays can be used to monitor energy storage, and disconnect the energy storage/facility from the grid. 4. A combination of software and hardware controls allows seamless control of energy storage to allow interconnection to utility. 5. The AC and DC disconnects on the inverters themselves are lockable and disable the inverter from operation. 6. The disconnects on the inverters could serve as the utility required disconnects for interconnection.

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.
- Establishes a tool to optimize conceptual design for a microgrid given location, load shape, and rate structure.

Potential future applications for similar projects:

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

STEP Project Report

Period Ending December 31, 2019

STEP Project Name:

Smart Inverter Project (COMPLETE)

Project Objective:

To investigate the capabilities of smart inverters and their impact and benefit for the Company's electric distribution system. This project is completed and final reports are included as Attachments.

Project Accounting:

	2017	2018	2019	Total
Annual Collection (Budget)	$0.00	$450,000	$0.00	$450,000
Annual Spend (Capital)	$0.00	$0.00	$0.00	$0.00
Committed Funds	$0.00	$0.00	$0.00	$0.00
Uncommitted Funds	$0.00	$0.00	$0.00	$0.00
Internal OMAG Expenses	$0.00	$33,861	$0.00	$33,861
External OMAG Expenses	$0.00	$349,998*	$0.00	$349,998
Subtotal	$0.00	$383,859	$0.00	$383,859

*External OMAG includes a contractual payment of $250,000 to Electric Power Research Institute and $100,000 to Utah State University for their services on the project.

Project Milestones:

Milestones	Delivery Date	Status/Progress
Hosting Capacity Study of RMP Distribution Circuits	6/31/2018	Complete
Laboratory Evaluation of Smart Inverters	09/30/2018	Complete
Smart Inverter Setting Analysis	8/31/2018	Complete
Review of Interconnection Requirements and Industry Practices	10/31/2018	Complete

Key Challenges, Findings, Results and Lessons Learned:

Description of Investment

STEP funding for this project was used to investigate the capabilities of smart inverters and their positive and negative impacts on RMP's electric distribution system.

Anticipated Outcome

- Evaluate readiness level of smart PV and battery inverters to comply with the new IEEE 1547-2018 standard.
- Performance analysis of smart inverters during both steady state and transient operating conditions.
- Investigate hosting capacity and potential benefit of smart inverters for several Rocky Mountain Power feeders.
- Analyze smart inverter settings in detail for two different feeders, and report on the range, requirements, and benefit of adjustability.
- Summarize current utility practices for voltage/frequency ride-through and communication between inverters and utility.

Challenges

- There are differences in the ability to control the inverters using Modbus communication protocol, and all the settings cannot be programmed using this protocol.

Findings/ Results

- All the tested PV inverters are compliant with the settings listed in category 2 of the IEEE 1547-2018, except Inverter 2, which is only compliant with category 1, and hence can only be used in areas with low distributed energy resources (DER) penetration.
- Three phase PV inverters are capable of injecting 100% and absorbing 95% of rated active power. Single phase PV inverters, however, are capable of injecting and absorbing 45%-65% of rated active power.
- Over the load range of 10%-100%, the efficiency of all the inverters is higher than 95%
- The battery inverter does not comply with most of the tests designed for smart inverter testing.
- The battery inverter ensures a continuous supply to the backup load, and establishes its local voltage within two fundamental cycles.
- Some of the distribution feeders studied showed hosting capacity gains by using smart inverters; however, most saw limited improvement due to already being thermally constrained.
- Because improvements in hosting capacity depended greatly on the connection point, the improvements were smaller for distributed systems than central systems because the locations were less finely controlled.

Lessons Learned

- The performance of all PV smart inverters matches closely to the manufacturer specifications. However, for the same power ratings, the performance of inverters differs among manufacturers.
- All PV inverters are suitable for grid integration in accordance with several of the IEEE 1547-2018 standard requirements, and autonomously support grid during voltage transients.
- In addition to hosting capacity, reactive power from inverters can be used to improve distribution losses and substation power factor.
- With the “best” settings, Volt-VAR control performed better than the fixed power factor function; however, with bad settings the performance was worse than all fixed power factor levels.
- Use of several smart inverter functions (such as Volt-VAR) will require updates to PacifiCorp’s Generator Interconnection Policy (Policy 138).
- IEEE 1547 introduces the requirement for DER to have communications capability over an open protocol, utilities have not converged on an approach to interfacing with these devices.

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, 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.
- Provides guidance to the Company’s distribution engineers to enhance the 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 that 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 increased deployment of distributed and renewable energy sources for its customers.

Potential future applications for similar projects:

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

STEP Project Report

Period Ending December 31, 2019

STEP Project Name:

Battery Demand Reponse

Project Objective:

Rocky Mountain Power has partnered with Wasatch Development on their 600 unit multi-family development in Herriman, Utah. The apartments, known as Soleil Lofts, feature solar panels on the rooftops and a large storage battery within each unit. The batteries are integrated to the grid for system-wide demand response. The Battery Demand Response Project provides Rocky Mountain Power experience in solar and battery integration. The Company will also gain valuable real-world experience in advanced grid management during peak/off-peak energy use.

There are three main objectives we are seeking with this program: 1) better understanding of demand response 2) how behind-the-meter behavior affects load shaping, and 3) insights into creating rate design for customers with batteries.

Demand Response: The partnership with Wasatch Development will allow the company to utilize each battery for demand response at any given time. The Company can draw on this resource during peak grid loads which will reduce the peak load for the entire electric system.

Load Shaping: The Company has historically had limited access to behind-the-meter data. In the future, similar projects will likely be added to the grid and will interact with the grid load in new ways. Information gained in this project will help the Company plan for these future integrations.

Rate Design: By looking at behind-the-meter battery behavior, the Company can better understand how to create rate design pilots for customers with batteries.

Project Accounting:

	2017	2018	2019	Total
Annual Collection (Budget)	$0	$0	$0	$0
Annual Spend (Capital)	$0	$0	$4,270	$4,270
Committed Funds	$0	$0	$0	$0
Uncommitted Funds	$0	$0	$0	$0
Internal OMAG Expenses	$0	$0	$0	$0
External OMAG Expenses	$0	$0	$0	$0
Subtotal	$0	$0	$4,270	$4,270

Project Milestones:

Milestones	Delivery Date	Status/Progress
Project Approved by Public Service Commission of Utah Docket No. 16-035-36	June 28, 2019	Approved
Battery installations start	July, 2019	Completed
First Building Completed	September, 2019	Completed
Soleil Lofts become available for occupancy	Third quarter 2019	Completed
Project Kickoff meeting with PacifiCorp and Sonnen	December 1, 2019	Completed
Develop preliminary system communication design	December 15, 2019	Completed
RTU Configuration	March 31, 2020	Completed
Establish VPN setup and establish security protocol	March 31, 2020	Completed
Battery Demand Response (DR) test event	June 30, 2020	Scheduled
Last building completed.	September, 2020	Scheduled
Full 4.8 MW available for control	December, 2020	Scheduled

Program Benefits:

Knowledge and data gained from this project will allow the Company to explore the option of offering battery demand response technology in the future. Battery demand response could lead to lower costs for customers as well as less transmission congestion during summer peak loads.

The partnership with Wasatch Development allows the Company to study behind-the-meter behavior at a much cheaper price than starting a similar program from scratch. Information gained from this project, can be used to develop future rate design options for battery-system-integrated customers. Also, what we learn in this project, will enable a larger roll-out of similar projects in the future.

Potential future applications for similar projects:

Work with developers and other industry partners to identify and potentially deploy battery demand response systems connected to the grid that benefit the customer with lower rates and benefit the Company with lower peak load.

STEP Project Report

Period Ending December 31, 2019

STEP Project Name:

Intermodal Hub

Project Objective:

The Intermodal Hub Project will develop a power balance and demand management system for multi modal vehicle charging at sites with high peak power demand. The Intermodal Hub Project is designed to address the high cost of grid infrastructure needed for high output chargers by researching methods to adaptively manage power flow between the grid and various electric charging needs. The project will combine a diversity of electric charging needs (light rail, bus, passenger, truck, and ride hailing services) at an intermodal transit center to create a multi-megawatt, co-located, coordinated, and managed charging system.

Project Accounting:

	2017	**2018**	**2019**	**Total**
Annual Collection (Budget)	$0.00	$0.00	$0.00	$0.00
Annual Spend	$0.00	$0.00	$802,510	$802,510
Uncommitted Funds	$0.00	$0.00	$0.00	$0.00
Internal OMAG Expenses	$0.00	$0.00	$0.00	$0.00
External OMAG Expenses	$0.00	$0.00	$0.00	$0.00
Subtotal	$0.00	$0.00	$802,510	$802,510

Project Schedule:

Project Task	**2019**		**2020**				**2021**			
	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Analysis and Planning										
Simulation Planning/Validation										
Testbed for Software/Hardware										
Deployment and Evaluation										

Project Milestones:

Milestones	Delivery Date	Status/Progress
Task 1 Analysis and Planning: Multi modal charging analysis (power levels, vehicle types)	3/31/2020	In Progress – Consideration of current e-buses and charge equipment requirements have been accounted in learning model. Priority meters across the UTA site have been identified. Coordination with both UTA and RMP to obtain meter history for input to learning algorithms and load modeling. Continued development of model to simulate site dynamics and load optimization.
Task 1 Analysis and Planning: Distribution capacity/needs/impact analysis	3/31/2020	In Progress – Ongoing development of Open DSS model to evaluate electric distribution loading. Conversion of CYME files to model input format. Additional meter information required for review and model implementation.
Task 1 Analysis and Planning: City and suburban level planning of grid and transportation charging integration	3/31/2020	In Progress – Site walk/review and CYME files of grid. Open DSS modeling to identify capacities and optimization potentials for charging equipment.

Task 1 Analysis and Planning: Confirm study participants in addition to UTA (e.g., fleet, including delivery and ride hailing participant vehicles)	3/31/2020	In Progress – Determination with site (UTA) of current electric bus status and future planning. Site review for feasibility of EV public access and control. Discussions with EV charging equipment vendors (ABB) and third-party EV managers (Greenlots, EV Connect) to understand limitations of current management software and identify requirements for active control through USU developed algorithms.
Task 2 – Distribution System Simulation Planning and Validation Design initial intelligent prediction algorithms and demand response concepts	3/31/2021	In Progress – Algorithm development in Matlab. Integration of learning algorithm with agent model. Identification of rewards (e.g. pricing, battery SOC, load optimization, etc).
Task 2 – Distribution System Simulation Planning and Validation: Develop system simulation models for charging network and agent-based vehicle response	3/31/2021	In Progress – Initial agent-based models are being developed through Open AI Gym and Matlab. Reward identification and coding in process. Continued inputs and improvements as data inputs are received (both historical and realtime when available).
Task 2 – Distribution System Simulation Planning and Validation: Collect data from TRAX power feed and TRAX light rail cars; e-bus fleet; all charging equipment; fleet (including delivery and ride hailing participant vehicles) Data used for algorithm development and as machine learning training datasets	3/31/2021	In Progress – Planning process for data acquisition and hardware installation. Receipt of historical meter data from RMP for identified priority meters. New Flyer e-bus performance reports. ABB depot charger data through Driver Care and local data logger in progress.

Task 2 – Distribution System Simulation Planning and Validation: Perform systems level simulation analysis for early and broad deployment scenarios, validate benefit of managed approach when compared to worst-case design approach	3/31/2021	Not Started
Task 3 – Testbed for Software/Hardware Development and Integration: Specify, bid, and procure system hardware	6/30/2021	In Progress – Discussion with EV equipment vendors (ABB) and third-party software management (Greenlots, EV Connect) for integration and public access
Task 3 – Testbed for Software/Hardware Development and Integration: Anticipate needs for and develop cyber security management Design for compatibility with and security of communication network	6/30/2021	Not Started
Task 3 – Testbed for Software/Hardware Development and Integration: Write code and program algorithms on servers Algorithms include energy/load balancing and management Design for compatibility with AMI	6/30/2021	Not Started
Task 3 – Testbed for Software/Hardware Development and Integration: Evaluate hardware system (with integrated software) at the USU EVR	6/30/2021	Not Started
Task 3 – Testbed for Software/Hardware Development and Integration: Iterate algorithm designs and develop pilot demand response program	6/30/2021	Not Started

Task 4 – Deployment and Evaluation: Integrate hardware and software systems with UTA and RMP equipment and cyber secure communication network	12/31/2021	Not Started
Task 4 – Deployment and Evaluation: Integrate hardware and software systems with UTA and RMP equipment and cyber secure communication network	12/31/2021	Not Started
Task 4 – Deployment and Evaluation: Integrate hardware and software systems with UTA and RMP equipment and cyber secure communication network	12/31/2021	Not Started
Task 4 – Deployment and Evaluation: Deploy hardware system at the UTA multi-modal hub site through a phased approach in direct coordination with IT and operations at UTA	12/31/2021	Not Started
Task 4 – Deployment and Evaluation: Finalize recruiting, engage work with participants for pilot demand response program	12/31/2021	Not Started
Task 4 – Deployment and Evaluation: Integrate real-time data collection from all partners and participants into the hardware system	12/31/2021	Not Started

Task 4 – Deployment and Evaluation: Evaluate power control and demand response performance; iterate algorithms; develop best practices and recommendations	12/31/2021	Not Started

Key Challenges, Findings, Results and Lessons Learned:

Description of Investment	Anticipated Outcome	Challenges	Findings	Results	Lessons Learned
a. Understanding of system and energy requirements to be managed	a. Gather necessary meter inputs from site loads and charging equipment. Develop learning and electrical system models.	1. Charge equipment and meter information in as close to real-time as possible	1. In Progress	1. In Progress	1. Continued efforts in installing required hardware for metering information
a. Active control of EV equipment – OCPP communication (Open Charge Point Protocol)	a. Receive inputs in realtime and actively control EV equipment	1. Installation of local communication for realtime data and active control. Limitations/lag through cloud database and current OCPP	1. In Progress – discussion with third party EV software management	1. In Progress	1. Realtime control anticipated to be accomplished in a laboratory setting and limited communication requirements, with increased complexities and public access, integration with third-party EV managers necessary. Currently these third-party managers are not actively controlling charge capacity to assist with load balancing across a site.

Potential future applications for similar projects:

A key outcome of this project will be a "roadmap" for high power electric vehicle charging complexes that leverage existing infrastructure from dominant peak loads such as TRAX to support a host of additional multi modal vehicle charging needs at minimal cost. The roadmap guides the confluence of accommodating different vehicle types with combined known loading and scheduling of charging (expected and variable) and peak pricing/surge charging to level peak demand loading on the grid.

The system will serve as a model for deployment of highly efficient and intelligent power management systems to additional UTA and Company sites. It also enables leadership in managing charging demands that can disseminated to other agencies regionally, nationally and globally.

STEP Project Report

Period Ending December 31, 2019

STEP Project Name:

Advanced Resiliency Mangement System

Project Objective:

The ARMS project enables outage notifications from existing ERT[1] electric meters, installation of communication radios on distribution line equipment, and deployment of line sensor technology on distribution circuits. These technologies connect critical customers and enable real-time information exchange with the Company's control center. The Company will also study if there would be benefits of deploying this technology on distribution circuits that have poor reliability.

Project Accounting:

	2017	2018	2019	Total
Annual Collection (Budget)	$0	$0	$1,430,000	$1,430,000
Annual Spend (Capital)	$0	$0	$39,931	$39,931
Committed Funds	$0	$0	$0	$0
Uncommitted Funds	$0	$0	$0	$0
Internal OMAG Expenses	$0	$0	$0	$0
External OMAG Expenses	$0	$0	$0	$0
Subtotal	$0	$0	$39,931	$39,931

Spend in 2019 was under the budgeted amount due to software license purchases being delayed from 2019 to 2020 and 2021. Overall budget for project has not been changed.

Project Milestones:

Milestones	Delivery Date	Status/Progress
Request for DOE funding	August 2019	Complete
Test cellular communications for distribution protection devices	December 2019	Complete
Develop process to finalize circuit list for fault indicator installation	December 2019	Complete
Finalize Circuit List	June 2020	On Target
IT Cybersecurity clearance	June 2020	On Target
Test fault indicators	June 2020	On Target
Test EGMs	April 2021	On Target

[1] An encoder receiver transmitter (ERT) is a technology that allows manual meter reading to be replaced by a human driving an automobile equipped with a special computer and radio receiver. The meter's consumption data is transmitted through a simple digital radio protocol. This general technique has come to be known as automated meter reading, or AMR.

Procure & Install EGMs	Oct 2021	On Target
EGMs Go Live	Dec 2021	On Target

Project Benefits:

- Reduces manual and mobile metering requirements by removing seven meter reading/collection FTEs and associated overhead.
- Provides meter tampering detection. This ability will improve Rocky Mountain Power's ability to detect and prevent theft.
- Provides interval usage data to Utah customers through the Company's website.
- Provides a platform that can be leveraged for future grid modernization applications including distribution automation, outage management, data analytics and demand-response programs.
- Reduces customer property visits, meter-reading miles, and employee exposure to safety hazards.
- Reduces CO_2 emissions through fewer Rocky Mountain Power vehicles on the road.
- Improves outage response operations by leveraging real-time information from distribution line device. Helps determine safe switching procedures and cost effective capital improvement and maintenance plans.
- Improves reliability metrics such as Sustained Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI).
- Leverages real-time information collected from distribution line equipment to augment predictive capability of existing outage management systems and reduces Company reliance on customer reporting for outage notification.
- Reduces operations and maintenance costs by eliminating the need for manual load reading performed on circuits that do not have sophisticated meters with remote communication capabilities.

Potential future applications for similar projects:

Lessons learned in this project can be used for a wide range of meter and circuit installations in the future. As improvements are made to the system, the Company can upgrade the system using the knowledge and experience gained from this project.

Utah Solar Incentive Program (USIP)

The USIP amounts shown on page 1.0 represent the actual expenditures of the USIP program. When STEP commenced, the Company anticipated that a portion of STEP revenues would be necessary to fund the remainder of the USIP program obligations through 2023. The Company's September 12, 2016, application in Docket No. 16-035-36 assumed funds would be needed for all remaining USIP project applications that had received, or were expected to receive, conditional approvals but had not yet qualified for incentive payments. At that time, the remaining USIP obligations was estimated to be $33.6 million. Since 2016, an estimated $14.2 million of projects that were previously approved for incentives have expired and are no longer eligible to receive USIP funds. Therefore, the revenues collected under the discontinued Electric Service Schedule 107 ("Schedule 107") are sufficient to cover all remaining USIP incentive obligations without the use of any of the $50 million in STEP funds.

Currently, a portion of revenues collected under STEP are credited to the USIP account. On June 28, 2019, the Commission approved the Company's request to use the STEP funds that were previously budgeted for USIP for the Advanced Resiliency Management System project. On August 20, 2019 the Commission approved the Company's request to begin refunding $3.06 million in surplus revenue collected through Schedule 107 through a reduction in Electric Service Schedule No. 196 Sustainable Transportation and Energy Plan ("STEP") Cost Adjustment Pilot Program rates over one year beginning November 1, 2019[1]. For transparency and consistency with prior reports, the company will continue to report USIP expenses in the annual STEP reports for as long as STEP revenues are booked to the USIP account.

Table 1 provides the CY 2019 USIP account balance with USIP collections under Schedule 107.

Table 1: USIP Account Summary (With Electric Service Schedule 107 revenues only)

Utah Solar Incentive Program Account - Through 2019											
		Order	Program Total	2012	2013	2014	2015	2016	2017	2018	2019
Program Revenue			(26,298,037)	(961,324)	(6,293,704)	(6,320,828)	(6,317,639)	(6,323,285)	(308,633)	-	227,376
Program Expenditures:											
	Incentive	331190, 338901		-	981,796	2,328,676	3,292,006	4,884,763	4,766,963	3,459,713	2,317,571
	Program Administration	331191; 338902		-	253,665	322,664	173,248	412,866	94,788	27,098	13,807
	Marketing	331192; 338903		55,905	35,744	25,995	14,515	336	-	-	-
	Program Development	331193' 338904		30,748	99,140	577	-	-	-	-	-
	Expired Deposits	331194; 338905		-	-	-		(103,963)	(99,568)	-	(157,638)
		408641							-	-	-
	Cool Keeper program			-	-	-	-	(200,000)	-	-	-
Total Expenditures			23,031,414	86,653	1,370,345	2,677,912	3,479,769	4,994,002	4,762,183	3,486,811	2,173,740
Interest			(3,451,708)	(5,995)	(219,165)	(473,909)	(721,712)	(685,628)	(627,425)	(569,938)	(147,937)
USIP Account Balance (Sch. 107 only)			(6,718,331)								

The Total Expenditure amounts showing for CY 2017, 2018 and 2019 tie to the USIP expenditures on page 1.0 of this report and also tie to Table 15 in the Company's USIP annual reports[2].

The 2019 program revenue of $227,376 shown in Table 1 for CY 2019 represents the credits back to customers through the reduction in Schedule 196 beginning November 1, 2019. The USIP workpaper provides the updated forecast program expenditures.

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[1] See Docket No. 19-035-T12.

[2] See Docket No. 18-035-24 and Docket No. 19-035-25 for CY 2017 and 2018 total expenditures, respectively. The CY 2019 USIP annual report will be filed June 1, 2020.