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Midwestern Regional Carbon Sequestration Partnership (MRCSP) Phase III (Development Phase)

Distributed Temperature Sensing (DTS) to Monitor CO_2 Migration in an Enhanced Oil Recovery Field in Northern Michigan

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Notice

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Acronyms and Abbreviations

3D	Three-Dimensional
BGS	Below Ground Surface
CO_2	Carbon Dioxide
CO_2-EOR	Carbon Dioxide-Enhanced Oil Recovery
DAS	Distributed Acoustic Sensor
DLS	Dog Leg Severity
DOE	United States Department of Energy
DTS	Distributed Temperature Sensing
EERC	Energy and Environmental Research Center
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
KOP	Kickoff Point
Md	Millidarcies
MD	Measured Depth
MMbbls	Million Barrels
MMP	Minimum Miscibility Pressure
MRCSP	Midwest Regional Carbon Sequestration Partnership
MT	Metric Tons
NETL	National Energy Technology Laboratory
NNPRT	Northern Niagaran Pinnacle Reef Trend
OOIP	Original Oil in Place
OTDR	Optical Time Domain Reflectometry
PCOR	Plains CO_2 Reduction
PNC	Pulse Neutron Capture
psi	Pounds per square inch
SECARB	Southeast Regional Carbon Sequestration Partnership
SPF	Shot Per Foot
TD	Total Depth
TVD	True Vertical Depth

1.0 Introduction

The Midwest Regional Carbon Sequestration Partnership (MRCSP) was established in 2003 by the U.S. Department of Energy/National Energy Technology Laboratory (DOE/NETL) to assess the technical potential, economic viability, and public acceptability of carbon sequestration within the midwestern United States. This task is part of the Michigan Basin Large-Scale Injection Project, and since the research began, MRCSP has successfully monitored net storage of more than 1 million metric tons (MT) of carbon dioxide (CO_2) into the Northern Niagaran Pinnacle Reef Trend (NNPRT). Carbon dioxide enhanced oil recovery (CO_2-EOR) in northern Michigan has been conducted since 1996, with the cumulative injection totaling more than 2 million MT.

The NNPRT consists of closely spaced but highly compartmentalized pinnacle reefs located about 6,000 feet (ft.) below ground surface (BGS) (Haagsma, et al., 2020). Various monitoring methods have been used to understand the behavior of CO_2 in these closed reservoir systems. Monitoring methods that have been used in these reefs include surface and borehole seismic technologies, geophysical logging, geochemistry monitoring, and bottomhole pressure and temperature monitoring. Pressure and temperature monitoring are typically done using memory-style gauges placed inside the well at reservoir depth (Mishra, et al., 2020). Memory gauges do not provide real-time data, nor do they provide the vertical spatial resolution necessary to assess conditions along the entire wellbore. These limitations may be overcome with distributed temperature sensing (DTS) using fiber optic cable as a distributed sensor (Shatarah and Olbrycht, 2017) that measures temperature at intervals along the length of the fiber, which can be extended from surface to bottom hole.

One of the tasks completed under MRCSP was the analysis of CO_2 flow patterns using DTS data. This task is based on DTS data acquired from the Chester 16 pinnacle reef located in Otsego County, Michigan. The reef is comprised of two formations, including the A1 Carbonate, with an area of 157 acres, and the underlying Brown Niagaran, with an area of 124 acres. The original oil in place (OOIP) is estimated to be approximately 6.8 million barrels (MMbbls). Chester 16 underwent primary production between 1971 and 1983, followed by a brief period of secondary water flood injection in 1983 and 1990. During primary and secondary production, the reef produced approximately 2.4 MMbbls of oil, recovering approximately 35% of the OOIP. After 1990, the reef was abandoned and laid dormant until 2017, when Core Energy started tertiary oil production using CO_2-EOR. As of August, 2019, approximately 147,000 MT of CO_2 was injected toward an initial miscible flood. The reef currently has one injection well (Chester 6-16) and one monitoring well (Chester 8-16). DTS is installed in both wells.

On its own, DTS provides a means to track temperature within the wellbores in real time. DTS data, when combined with other reservoir and operational data such as the injection rates, bottomhole pressures and temperature, characterize the migration patterns of CO_2 in the subsurface. The primary objective was to determine the distribution of CO_2 inflow zones within the A1 Carbonate and Brown Niagaran Formation. Changing the configuration of various well components allows Core Energy to inject CO_2 to either of these two formations, alone or as combined.

2.0 DTS Technology

DTS is a distributed sensing technology that uses fiber optic cable as a temperature sensor (other related technologies include Distributed Acoustic Sensing and Distributed Strain Sensing). In its simplest form, the glass fiber is interrogated using a laser pulse and the assemblage of returned light signals over time is analyzed. The returned light signal is the result of backscattered light waves released by atoms in the matrix of the fiber in reaction to the initial laser pulse. The timing of a given returned signal is related to the location of that measurement on the fiber (using known light travel time in the fiber), and the character and magnitude of the returned signal is used to compute the temperature at that point.

There are multiple types of backscattered signals created in response to a laser pulse. Raman backscattering (Raman, 1928) is typically the basis of DTS temperature measurements. Other types of backscattering include Rayleigh and Brillouin backscattering; other distributed measurement systems use these signals or a combination of them. The Raman signal is composed of Stokes and Anti-Stokes frequency bands. The Stokes band is weakly temperature dependent, whereas the Anti-Stokes band is strongly temperature dependent. Therefore, a temperature reading is computed from the ratio of Anti-Stokes to Stokes signals.

In practice, DTS temperature systems typically provide temperature measurements at 1-meter (m) spacing along the entire cable. The timing of a single DTS survey pass is limited in theory by the time needed to interrogate the entire cable length, but in practice by the speed of processing the data, which is still typically less than a millisecond. A single DTS pass, as described in the previous paragraphs, would have poor signal-to-noise ratio, and so in practice, a DTS interrogator unit will repeat and combine or “stack” multiple DTS passes to achieve acceptable signal-to-noise ratio. Typical downhole DTS installations might stack passes such that a DTS survey is generated every one to five minutes, but hourly DTS results were generally used in this task.

2.1 Field Applications of DTS

DTS technologies have been deployed for a wide variety of applications, including measurement and monitoring of near-surface hydrologic processes (groundwater-surface water interactions), management and monitoring of secondary oil recovery methods such as steam flood performance (Saputelli et al., 1998), water alternating gas operations (Brown et al., 2004), and estimation of water injection and oil production profiles (Ouyang and Belanger, 2006). The ability of DTS technology to monitor downhole temperature conditions during CO_2 storage operations has been demonstrated at the pilot scale by the Regina-based Petroleum Technology Research Council’s Aquistore storage site (Miller et al., 2016), the US DOE-affiliated Southeast Regional Carbon Sequestration Partnership (SECARB) in Cranfield, Mississippi (Butsch et al., 2013), and the Ketzin project in Germany (Wurdemann et al., 2010).

A CO_2 monitoring survey similar to the work in this task was performed in an onshore Gulf of Mexico study area and highlights the usefulness of DTS data in identifying the arrival of a CO_2 plume at monitoring wells, especially in conjunction with pressure/temperature gauges (Nunez-Lopez et al., 2014). In this task, two wells placed 230 ft. and 367 ft. from the injection well were equipped with DTS. Formation cooling was recorded in both monitoring wells, and the cooling arrived at the furthest monitoring well prior to arriving at the closer monitoring well, confirming heterogeneity in the reservoir. As expected, the temperature front lagged behind the initial arrival of the pressure front observed in the wells by a matter of weeks.

3.0 Site Description

3.1 Reef Geology

The Chester 16 reef is in the Chester township of Otsego County, Northern Michigan. Figure 3-1 shows a map-view and three-dimensional (3D) view of the Chester 16 reef with the two wells. 3D seismic data and geologic characterization suggests the Chester 16 reef is actually two distinct reef cores near one another. The injection well Chester 6-16 penetrated the reef complex at a high flank position in the southern reef core area and the monitoring well Chester 8-16 penetrated the reef complex at a crestal position in the northern reef core area.

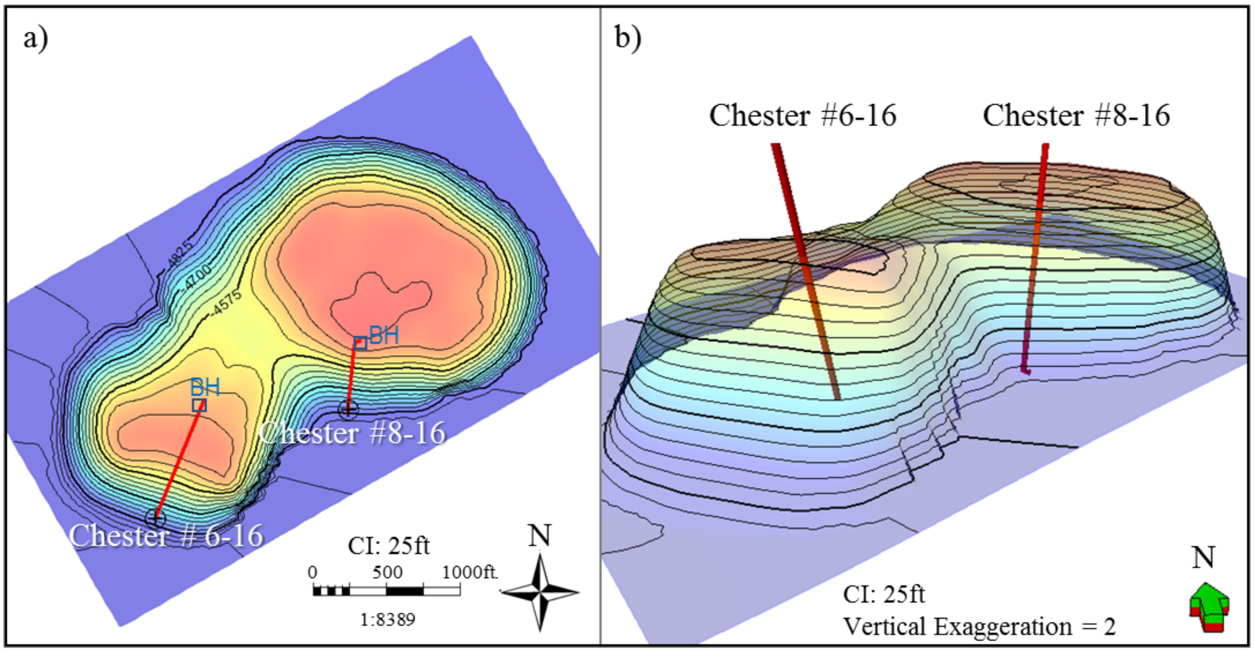


Figure 3-1. (a) Map-view of Chester 16 reef; (b) 3D view showing location of two wells.

Two formations comprise the reservoir in this reef—the A1 Carbonate and the Brown Niagaran Formations. The primary reservoir is the overlying A1 Carbonate, which has an average porosity of 9.8% and average permeability of 7.8 millidarcies (mD) based on core data. It has a distinct high porosity zone along the crest of the reef and is composed of porous dolomite. The A1 Carbonate is dense along the flanks of the reef, which limits the extent of the reservoir. The Brown Niagaran tends to have low average porosity and permeability (3% and 1.7 mD, based on core data) due to lack of dolomitization with occasional fractures and/or dolomitic zones. Salt plugging, which limits the available pore space, is common in the Brown Niagaran in the limestone reefs. However, it is not prevalent in the Chester 16 reef. These two formations are overlain by approximately 1,500 ft. of confining rock units comprised of interbedded salt, shale, and low porosity carbonate, which serve to confine the injected CO_2 within the target formations. The original oil-water contact occurs in the lower third of the reef structure, leaving two-thirds of the reef viable for EOR production.

3.2 Well Configurations

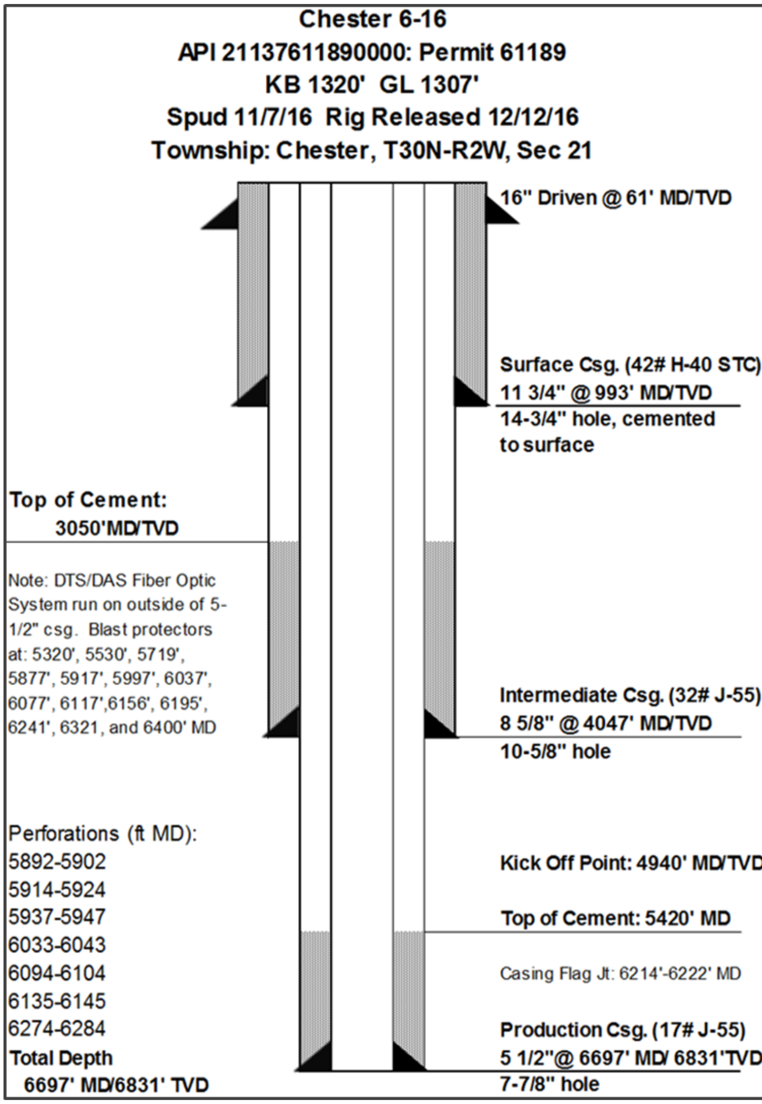
The Chester 16 reef has undergone prior primary production, with older wells now plugged & abandoned. Core Energy acquired this reef for CO_2-EOR purposes and drilled two new wells in the reef— Chester

6-16 injection well and the Chester 8-16 monitoring well. The Chester 8-16 well will eventually become a production well once the initial CO_2 flood is completed to pressurize the reef to its minimum miscibility pressure (MMP), approximately 1,300 psi operating pressure. At pressures above MMP, oil is expected to flow to the production well. By August 15, 2019, Core Energy had injected approximately 144,476 MT of CO_2 in this reef, and the Chester 8-16 monitoring well was perforated but not yet injecting CO_2 injection or producing oil.

3.2.1 Chester 6-16 Injection Well

The Chester 6-16 well was spudded in November 2016 and was completed in December 2016. It was directionally drilled from the kickoff point (KOP) at 4,047 ft. MD into the Gray Niagaran to a total depth (TD) of 6,697 ft. MD. The Gray Niagaran (6,513 ft. MD) serves as a sufficient underlying confining unit for the Brown Niagaran (5,970 ft. MD) and the A1 Carbonate (5,884 ft. MD), which are the two key reservoir intervals. The A2 Evaporite and the subsequent overlying formations serve as reservoir seals above the top of the A1 Carbonate.

The wellbore diagram for Chester 6-16 is shown in Figure 3-2. The maximum angle of inclination is 2.76 degrees and dog leg severity (DLS) does not exceed 1.3 degrees/100 ft. at any point along the well path trajectory. The well has three casing strings, including a 16-inch conductor casing set at 61 ft. MD (driven), an 11-3/4 inch surface casing set to 993 ft. MD and cemented back to surface, an 8 5/8 inch intermediate casing set to 4,047 ft. MD and cemented to 3,050 ft. MD, and a 5.5-inch injection casing set to 6,697 ft. MD and cemented to 5,420 ft. MD.



Formation Tops - based on KB		
Name	**MD**	**TVD**
BOD	857'	857'
Antrim	1,134'	1,134'
Trav Form	1,607'	1,607'
Trav Lime	1,647'	1,647'
Bell Shale	2,293'	2,293'
Dundee	2,363'	2,363'
Detroit River Group	2,601'	2,601'
Massive Anhydrite	3,125'	3,125'
Richfield	3,189'	3,189'
Amherstburg	3,372'	3,372'
Bois Blanc	3,493'	3,493'
Bass Island	3,950'	3,950'
G Unit	4,278'	4,278'
F Unit	4,315'	4,315'
F Salt	4,354'	4,354'
E Unit	5,073'	5,072'
D Unit	5,201'	5,198'
C Shale	5,245'	5,240'
B Unit	5,321'	5,311'
B Salt	5,361'	5,347'
A2 Carb	5,737'	5,649'
A2 Evap	5,839'	5,729'
A1 Carb	5,884'	5,762'
Brown Niagaran	5,970'	5,828'
Gray Niagaran	6,513'	6,242'

Figure 3-2. As-built wellbore diagram for Chester 6-16 (not to scale).

Perforations

The Chester 6-16 injection well was perforated in both the A1 Carbonate and the Brown Niagaran Formations. The well is completed with a tubing string, two packers, a plug positioned between the two formations, and a sliding sleeve system for directing injection together or separately to the two formations. The injection well is perforated at three locations in the A1 Carbonate Formation and four locations in the Brown Niagaran Formation (Table 3-1). Each perforated zone is 10 ft. deep and is shot once per foot (1 SPF).

Table 3-1. Perforation locations in the Chester 6-16 injection well.

Perforation #	Start Depth (feet, MD)	End Depth (feet, MD)	Formation
Perf 1	5,892	5,902	A1 Carbonate
Perf 2	5,914	5,924	A1 Carbonate
Perf 3	5,937	5,947	A1 Carbonate
Perf 4	6,033	6,043	Brown Niagaran
Perf 5	6,094	6,104	Brown Niagaran
Perf 6	6,135	6,145	Brown Niagaran
Perf 7	6,274	6,284	Brown Niagaran

When the A1 Carbonate Formation is targeted for injection, CO_2 is expected to flow through three perforated intervals within the formation. The contact between the A1 Carbonate and the Brown Niagaran is located at approximately 5,970 ft. (MD), and well components such as the plug and casing packers are set such that the Brown Niagaran Formation can be isolated from receiving injected CO_2. Two sets of downhole memory gauges were installed in the well (at bottom of A1 Carbonate and Brown Niagaran formations) to monitor pressure and temperature in each formation and monitor for communication across the plug between the formations.

Similarly, when the target of injection is the deeper Brown Niagaran Formation, the plug between formation contact will be removed and the sliding sleeve will be kept closed. This allows CO_2 to flow past the A1 Carbonate Formation and inject into the Brown Niagaran Formation where CO_2 is expected to flow through four perforated intervals within the formation. When both these formations are the target zone of injection, the sliding sleeve is kept open and the plug between formations is removed to allow flow into all seven perforations within both formations.

Lateral Drilling

Since starting CO_2 injection in the Chester 6-16, the injection rates/durations have been lower than anticipated. In order to increase the injection rates/durations, Core Energy proposed the installation of small-diameter (1.5”) lateral borings off the well to improve communication between the well and the reservoir. Between October 1 and 9, 2018, Radial Drilling Services Inc. attempted to install the laterals with limited success. Six laterals were planned to extend 300 ft. away from the well, but only four laterals were attempted due to the limited progress through the reservoir. The progress achieved for the four laterals is shown in Table 3-2.

Table 3-2. Radial drilling of laterals at Chester 6-16.

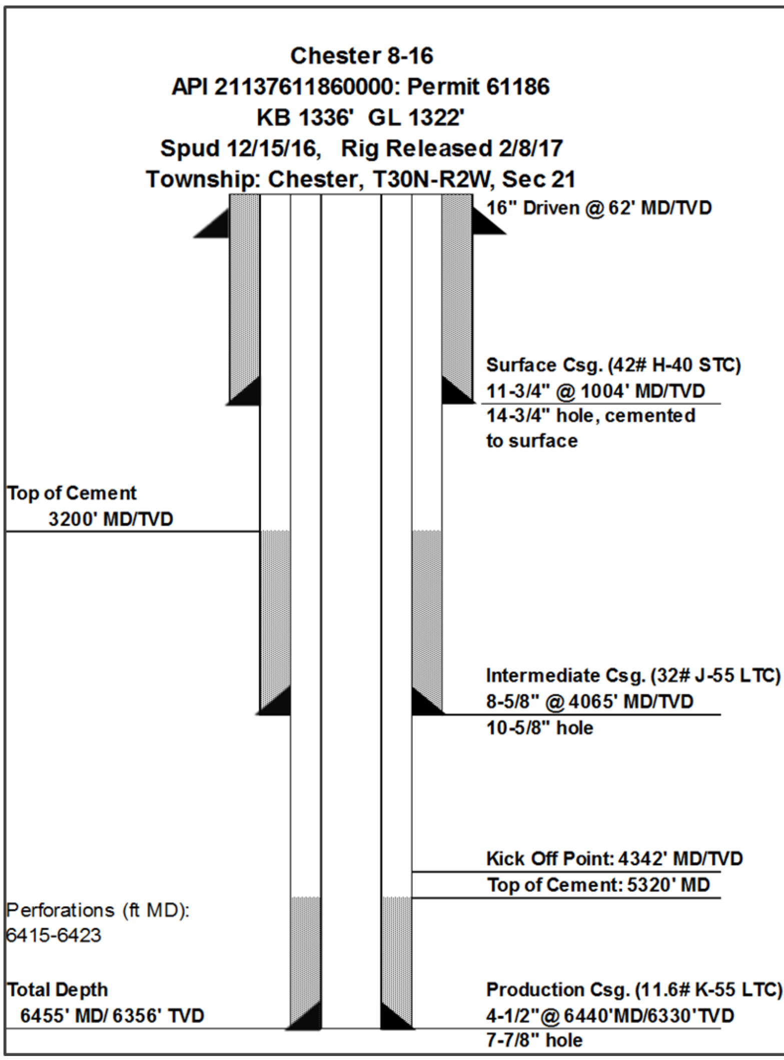
Lateral Depth (feet, MD)	Lateral Length (feet)
6,245	27
6,235	1
6,040	0
5,930	10

The limited success with the drilling of the laterals is attributed to the creation of pockets in the formation preventing forward thrust of the drill bit/jets. A variety of acid concentrations was used as the drilling fluid to minimize the production of the pockets without success. Following the work to install the laterals, the tubing and packer assemblies were placed in the well at the same locations they were placed prior to the lateral drilling job, and injection resumed in October 2018. The impact of radial drilling on injectivities is discussed in Section 4.4.

3.2.2 Chester 8-16 Monitoring Well

The Chester 8-16 well began drilling in December 2016 and was completed in February 2017 It was also directionally drilled from the KOP at 4,342 ft. MD/TVD into the Gray Niagaran to TD of 6,455 ft. MD (6,356 ft. TVD). The Gray Niagaran (6,332 ft. MD) serves as a sufficient underlying confining unit for the A1 Carbonate (5,843 ft. MD) and the Brown Niagaran (5,916 ft. MD), which are the two key reservoir intervals. The A2 Evaporite and the subsequent overlying formations serve as reservoir seals above the top of the A1 Carbonate.

The wellbore diagram for Chester 8-16 is shown in Figure 3-3. The well has the following casing strings: a 16-inch conductor casing set at 62 ft. MD (driven), an 11 3/4 -inch surface casing set to 1,004 ft. MD and cemented back to surface, an 8 5/8-inch intermediate casing set to 4,065 ft. MD and cemented to 3,200 ft. MD, and a 4.5-inch deep string casing set to 6,440 ft. MD and cemented to 5,320 ft. MD. DTS and distributed acoustic sensor (DAS) fiber optic arrays were also run in the Chester 8-16 well on the outside of the 4.5-inch casing. A five-level discrete sensor pressure and temperature (P/T) monitoring system was also installed behind-casing.



Formation Tops - based on KB		
Name	**MD**	**TVD**
BOD	873'	873'
Antrim	1,475'	1,475'
Trav Form	1,618'	1,618'
Trav Lime	1,657'	1,657'
Bell Shale	2,303'	2,303'
Dundee	2,372'	2,372'
Detroit River Group	2,607'	2,607'
Massive Anhydrite	3,130'	3,130'
Richfield	3,193'	3,193'
Amherstburg	3,375'	3,375'
Bois Blanc	3,491'	3,491'
Bass Island	3,955'	3,955'
G Unit	4,281'	4,281'
F Unit	4,318'	4,318'
F Salt	4,356'	4,356'
E Unit	5,133'	5,065'
D Unit	5,273'	5,191'
C Shale	5,313'	5,231'
B Unit	5,385'	5,297'
B Salt	5,419'	5,329'
A2 Carb	5,735'	5,639'
A2 Evap	5,805'	5,708'
A1 Carb	5,843'	5,746'
Brown Niagaran	5,916'	5,819'
Gray Niagaran	6,332'	6,235'

Figure 3-3. As built wellbore diagram for Chester 8-16. (Not to scale.)

Perforations

The Chester 8-16 monitoring well was perforated in July 2019 for injection purposes at three locations between the top of the A1 Carbonate (5,843 ft. MD) and the top of the Brown Niagaran (5,616 ft. MD). Each perforated zone is 10 ft. deep with six SPF, all oriented in the same direction. After perforating, Sage Rider performed a diagnostic test on the fiber optic cable mounted on the outside of the 4.5-inch production casing and determined that the cable is functioning normally and was not damaged by the perforating. As of August 2019, Chester 8-16 has not yet begun injection of CO_2.

3.3 DTS Installation

As part of the permanent monitoring systems installed in the Chester 16 reef, two fiber optic arrays were run behind the 5.5-inch casing on the Chester 6-16 injection well, a DAS array and a DTS array. The glass fibers were sheathed in stainless steel tubing strapped to the 5.5-inch casing. The sheathing protects the glass fibers during installation and during their life in the subsurface. This is a common practice when deploying DTS systems in subsurface petroleum operations.

Figure 3-4(a) shows the location of various well components in the bottom 900 ft. (5,700 to 6,600 ft. MD) in the Chester 6-16 injection well, including perforation locations listed in Table 3-3. Two multi-mode DTS fiber optic cables encased in a metal tube were installed outside the 5.5-inch diameter production casing from surface to bottom hole (approximately 6,650 ft. MD). Figure 3-4(b) shows the depth location of five behind-casing P/T sensors in the Chester 8-16 monitoring well. DTS fiber optic cable was installed outside the 4.5-inch production casing from surface to bottom hole (approximately 6,350 ft. MD). The behind-casing P/T sensors were positioned 90 degrees to the alignment of the fiber optic cable. One P/T sensor was installed in the A2 Carbonate, one in A1 Carbonate, and three in the Brown Niagaran Formation (Table 3-3). DTS and behind-casing P/T sensors both provide real-time surface readout pressure and temperature data.

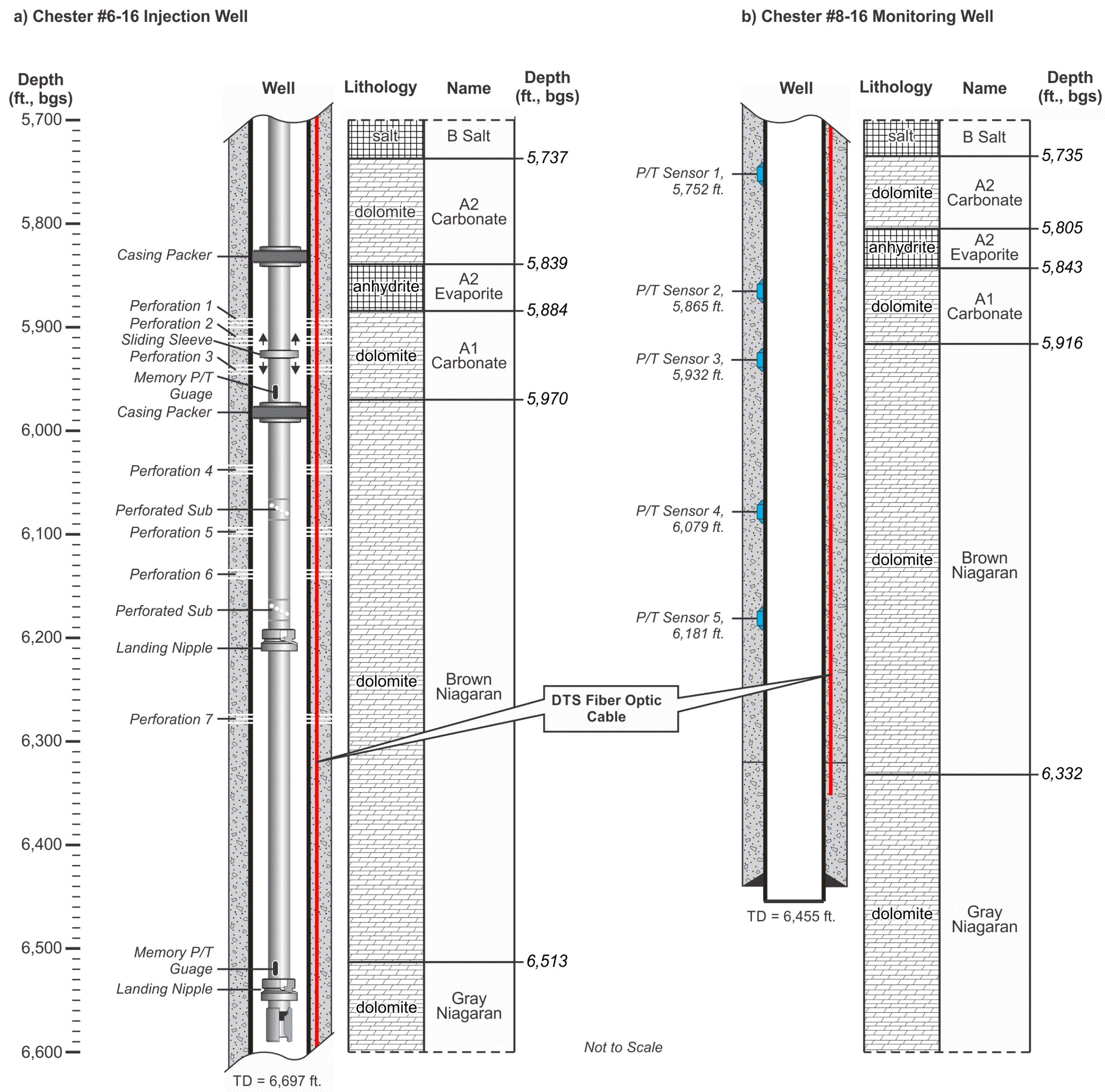


Figure 3-4. (a) DTS system and well components in Chester 6-16 injection well; (b) DTS system and behind-casing sensors in Chester 8-16 monitoring well. All depths shown are measured depths (MD).

Table 3-3. Pressure & Temperature sensor locations in the Chester 8-16 monitoring well.

Depth (feet, MD)	Formation
5,752	A2 Carbonate
5,865	A1 Carbonate
5,932	Brown Niagaran
6,079	Brown Niagaran
6,182	Brown Niagaran

The DTS system was monitored in real time using the DTS Configurator™ software utility (Figure 3-5) provided by SageRider. This software displays depth vs. temperature data at every 1m interval, and compiles readings for download by averaging temperature readings once per hour.

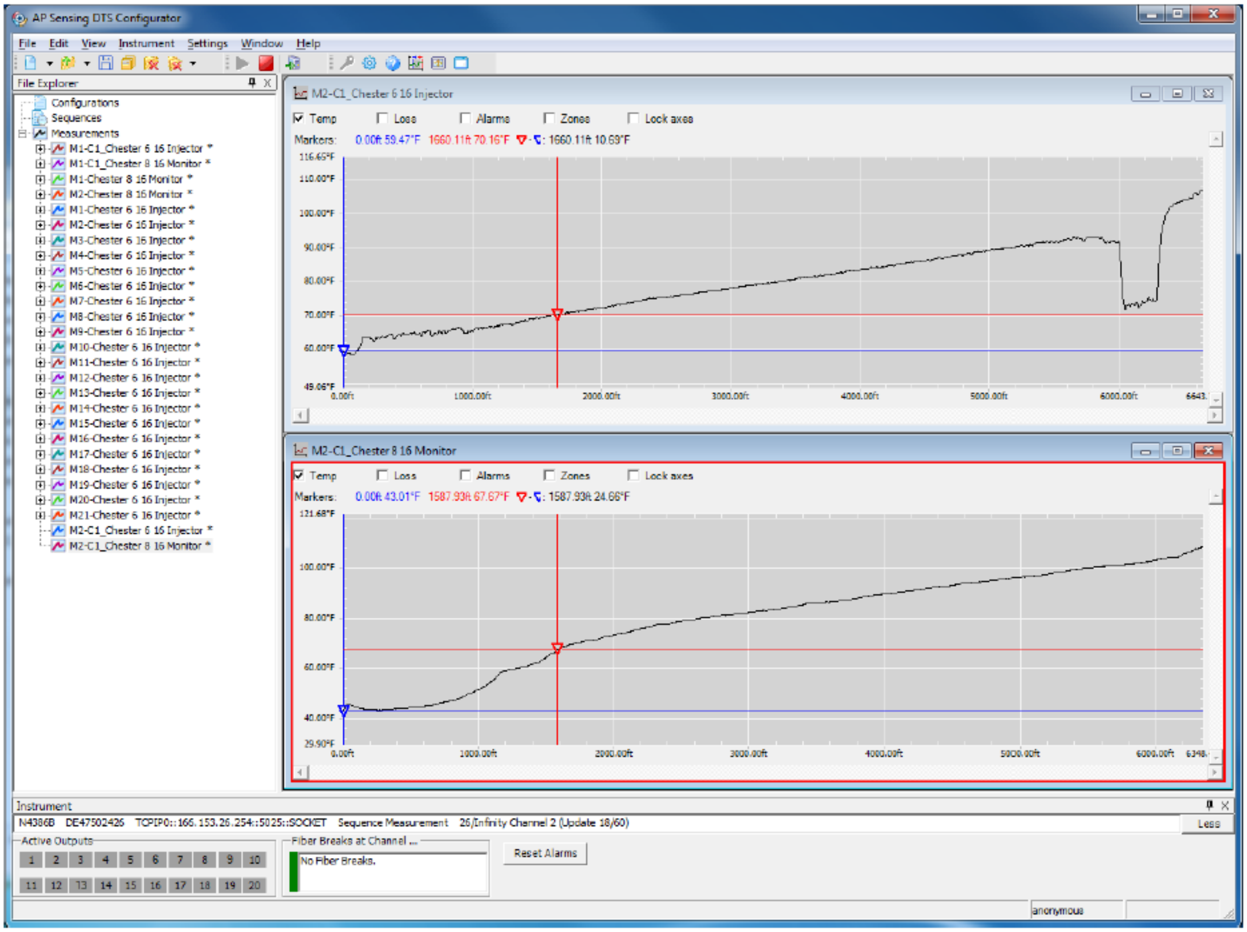


Figure 3-5. DTS Configurator Software

Similarly, the WellRanger™ software (Figure 3-6) allows real-time monitoring of behind-casing pressure and temperature sensors installed in the monitoring well. Also, the memory gauges placed in the injection well and the wellhead flow rate data are routinely downloaded and collated with the DTS and behind-casing sensor data by synchronizing date and time stamps. All data are compiled in a Microsoft Excel spreadsheet customized with Visual Basic for Applications for displaying profiles of depth vs. temperature in the injection and monitoring well for specified start/stop times, depth intervals, measured vs. TVD basis, displaying locations of formations, perforations and hardware components, and injection flow rates.

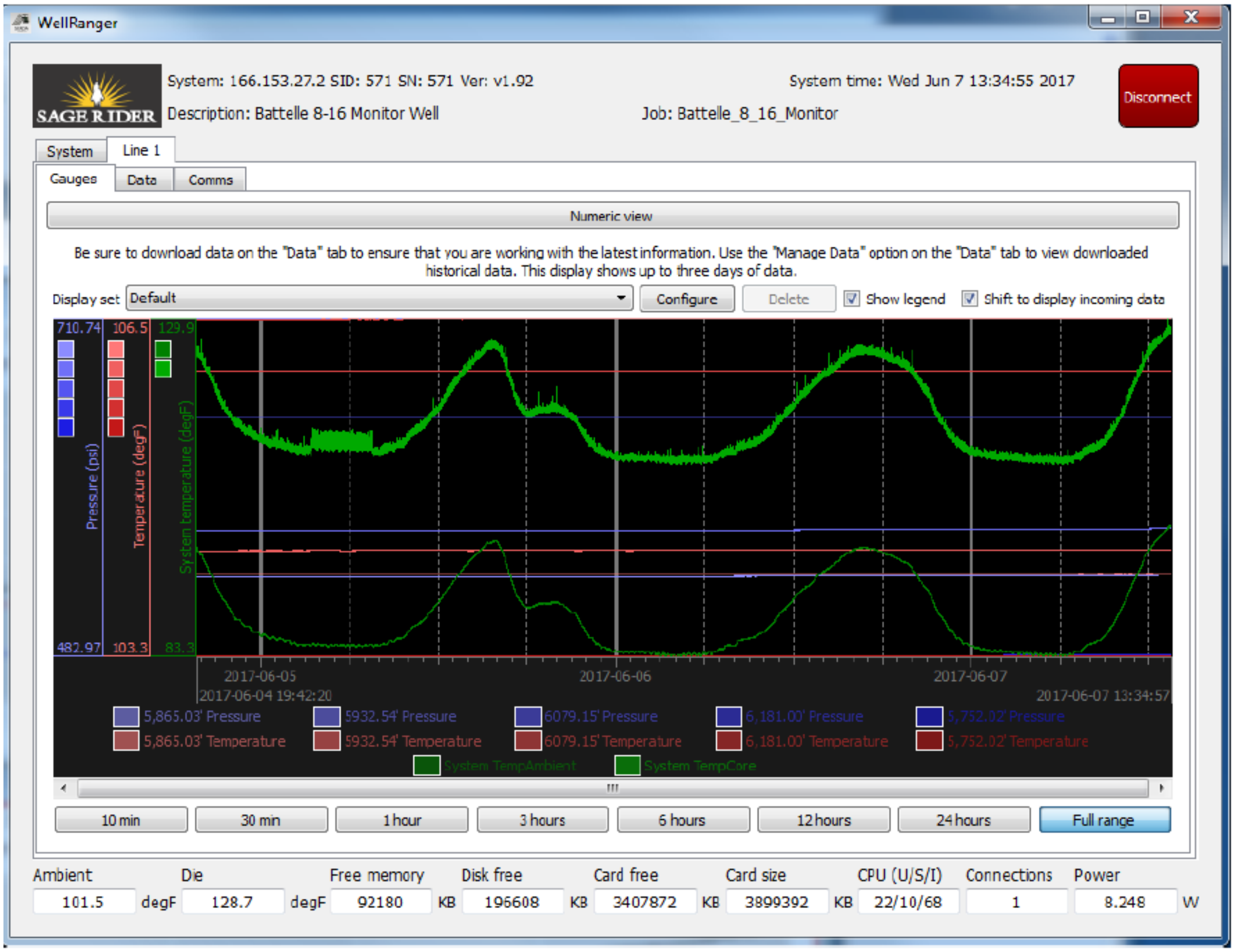


Figure 3-6. WellRanger software.

3.4 Other Instrumentation

In addition to the DTS, the Chester 6-16 injection well is instrumented with memory-style pressure and temperature recording gauges (PPS25 manufactured by Pioneer Petrotech). These gauges measure pressure up to 6,000 psi (± 0.03% full scale accuracy) and temperatures up to 257 °F (± 0.9 °F accuracy), and they were typically positioned at the bottom of the A1 Carbonate (5,970 ft. MD) and/or Brown Niagaran Formation (6,531 ft. MD). If CO_2 was being injected into the A1 Carbonate Formation only, memory gauges were placed in the well both at depths corresponding to the bottom of the A1 Carbonate and within the upper Brown Niagaran Formations. When CO_2 was being injected into the Brown Niagaran Formation only, or into the combined formations, memory gauges were only placed at the depth corresponding to the bottom of Brown Niagaran Formation. Additionally, the Coriolis mass flow meter provides injection rates (MT/day), density (kg/m^3), and temperature (°F) of the CO_2 being injected. There is no production tubing in the well, and there are therefore no memory pressure and temperature gauges in the well.

4.0 DTS and Operational Data Analysis

In this section, the target injection formations (A1 Carbonate and Brown Niagaran) are evaluated for each major injection periods for the cooling expected to occur when cooler CO_2 is introduced into warmer reservoir fluids. The temperature measured by the DTS system at various depths and analysis of the DTS data helps us understand the migration of CO_2 within the reservoir between the injection well and the monitoring well. Three specific objectives are evaluated using DTS data in conjunction with other operational and wireline data. These are:

1. Infer the inflow zone depths where CO_2 is entering the reservoir through perforations in the injection well;
2. Assess potential vertical migration of fluids along the well borehole; and
3. Monitor flow stratification in the reservoir and arrival of CO_2 at the monitoring well.

The CO_2 that is delivered to the Chester 6-16 wellhead is typically injected at surface between approximately 40 and 80 °F, while the native reservoir fluids within the A1 Carbonate and Brown Niagaran formations are found at approximately 100 °F. The basis of DTS analysis of injection is to infer fluid flow based on temperature changes (in time and in depth). The temperatures at a given time and depth are influenced by the existing reservoir temperature and the temperature of the injected fluid. For gas flow, temperatures are most strongly driven by Joule-Thompson cooling (Oldenburg, 2006)— strong cooling that occurs when the flowing fluid undergoes a pressure drop. Thus, cooling signals might be seen at perforations with active injection (where injected fluid drops pressure as it leaves the perforations into the reservoir), or at places where the fluid goes through a constriction in tubing for example. The Chester 6-16 injection well is perforated in seven intervals: three zones in the A1 Carbonate Formation and four within the Brown Niagaran Formation.

These basic ideas are the basis for qualitative injection and warmback analysis. Temperatures during injection indicate where injection fluids move in the wellbore, although they do not necessarily indicate where injection fluids are entering the reservoir. Warmback analysis, which is looking at how quickly locations warm back after injection has stopped, can be a clearer indicator of reservoir zones that have had more injection. Zones that have taken more injection will have had more reservoir subjected to cooling, and therefore will take longer to warmback than zones that had less injection. The warmback is affected mainly by cooling of fluids as they enter the reservoir, rather than cooling due to flow within the wellbore. Also, the Joule-Thompson expansion and cooling of CO_2 and the bottomhole pressure from the Brown Niagaran Formation is explored within the injection wellbore at depths below the A1 Carbonate. This is demonstrated by the unintended migration into Brown Niagaran Formation when the target injection zone was solely the A1 Carbonate.

Another objective was to verify whether CO_2 is migrating vertically along the injection well borehole outside the target formations for injection (A1 Carbonate and Brown Niagaran). To determine if this unintended migration occurred, the warmback of shallower (and deeper) formations where presence of cooler injectate (relative to reservoir fluids) has an impact on the time it takes for the formation to revert to the reference reservoir temperatures was analyzed.

Finally, the cooling signature observed by DTS within the A1 Carbonate Formation in response to injection of CO_2 at the Chester 6-16 injection well will be analyzed to address the arrival of CO_2 and the Chester 8-16 monitoring well. The DTS temperature signature and other corroborating data, such as changes in gas saturation observed between baseline and repeat Pulse Neutron Capture (PNC) logs in the Chester 8-16 well, pressure and temperature recorded by the behind-casing sensors, and wireline temperature logging were used to investigate non-isothermal injection systems as a possible explanation for arrival of CO_2 at the monitoring well.

4.1 Chester 16 Data Availability

The DTS system records temperature measurements in two wells at user-specified depths and time intervals. As configured, the two wells provide temperature at every 1m interval from the surface to the depth of the installed optic fiber, while the time-interval is set typically to once every hour. However, frequency of temperature polling can be set remotely as needed if more granular data is required. The temperature data are recorded on a data acquisition system installed near the wellhead. A DTS Configurator software utility provided by SageRider Inc., the vendor who installed the DTS system, allows for data to be downloaded periodically, as well as review conditions in real time. Additionally, the behind-casing sensors installed at five depths in the Chester #8-16 monitoring wells record both the pressure and temperature readings to a data recorder at surface. Another software utility, WellRanger, allows for monitoring real-time conditions and download recorded P/T data. Finally, the Chester #6-16 injection well has a Coriolis flow meter installed, which provides wellhead data for injection rates and P/T data available from bottomhole memory gauges in the A1 Carbonate and/or the Brown Niagaran formations. Together, following data is available from the Chester 16 reef:

- DTS temperature data (°F) in both injection and monitoring well, 1m interval, once every hour from surface to bottomhole
- Behind-casing pressure and temperature, once every hour at monitoring well
- Injection wellhead data including
  - Injection rates, MT/day
  - Injection temperature, °F
  - Wellhead tubing pressure, psi
- Bottomhole memory gauges installed in the injection well in A1 Carbonate and/or Brown Niagaran Formation
  - Pressure, psi
  - Temperature, °F

4.2 Chester 16 Reef Injection History

As of August, 2019, 147,000 MT of CO_2 has been injected in the Chester 16 reef. The total quantity of CO_2 injected is measured by a Coriolis mass flow meter located at the Chester 6-16 injection well and recorded daily in a production database. Table 4-1 shows the CO_2 injection periods and the intended injection formation(s). In Section 4.6, DTS data are analyzed to discern where injectate entered the reservoir for injection periods #2 through #8. Injection period #1 is not analyzed because the DTS was not installed during this brief injection period.

Table 4-1. CO_2 injection history of Chester 16 reef

Injection Period	Date Range	Days Injected	Fall off Days	Target Formation	Quantity Injected (MT)
1	1/11/17 - 1/14/17	3	39	A1 Carbonate	804
2	2/22/2017 - 4/6/2017	43	16	A1 Carbonate	9,039
3	4/22/2017 - 7/24/2017	93	67	A1 Carbonate	20,585
4	9/29/2017 - 11/27/2017	59	19	Brown Niagaran	18,314
5	12/16/2017 - 1/16/2018	31	20	A1 Carbonate	9,010
6	2/5/2018 - 3/21/2018	44	67	A1 Carbonate and Brown Niagaran	10,178
7	5/26/2018 - 8/14/2018	80	66	A1 Carbonate and Brown Niagaran	18,320
8	10/20/2018 - 8/15/2019	.		A1 Carbonate and Brown Niagaran	58,226
					144,476

4.3 Chester 6-16 Bottomhole Pressures

Figure 4-1 shows the highlighted injection periods (injection periods #2 to #8), along with daily injection rate, cumulative mass of CO_2 injected, bottomhole pressures recorded by memory gauge(s) placed in the target injection formation(s), and the wellhead temperature of injected CO_2. The pressure analysis was not conducted in this task. Instead, bottomhole conditions (circled areas C#1 and C#2 shown during injection periods #2 and #3) are presented with DTS data for evidence of unintended migration to the Brown Niagaran Formation when only the A1 Carbonate Formation was targeted for injection.

Usually, the pressure in the A1 Carbonate and the Brown Niagaran formations increases to approximately 3,600 psi when injection begins. However, pressure tends to fall back to approximately 2,000 psi during the fall off periods if enough time is allowed for near wellbore (injection well) conditions to stabilize. Also, near wellbore pressure conditions at the injection well should not be interpreted with the reservoir pressure further out within the reef. Pressure at the Chester 8-16 monitoring well would be a better indicator of reservoir pressures observed within the two target formations.

Lastly, the surface temperature of the CO_2 injected has an impact on the cooling observed within the injection wellbore and the subsequent cooling within the reservoir once injection has stopped. If the CO_2 is entering the reservoir significantly cooler than native reservoir fluids, cooling is likely to persist for a longer duration within the target zones receiving the cold CO_2. If the CO_2 being injected is already significantly warmer at surface and warmer by the time it is injected in deeper reservoir (closer to temperature of native reservoir fluids), then the reservoir will not experience any cooling and no warmback effects will be observed. The impact of surface temperature of injected CO_2 is discussed (where pertinent) in the differential temperature analysis in Section 4.6.

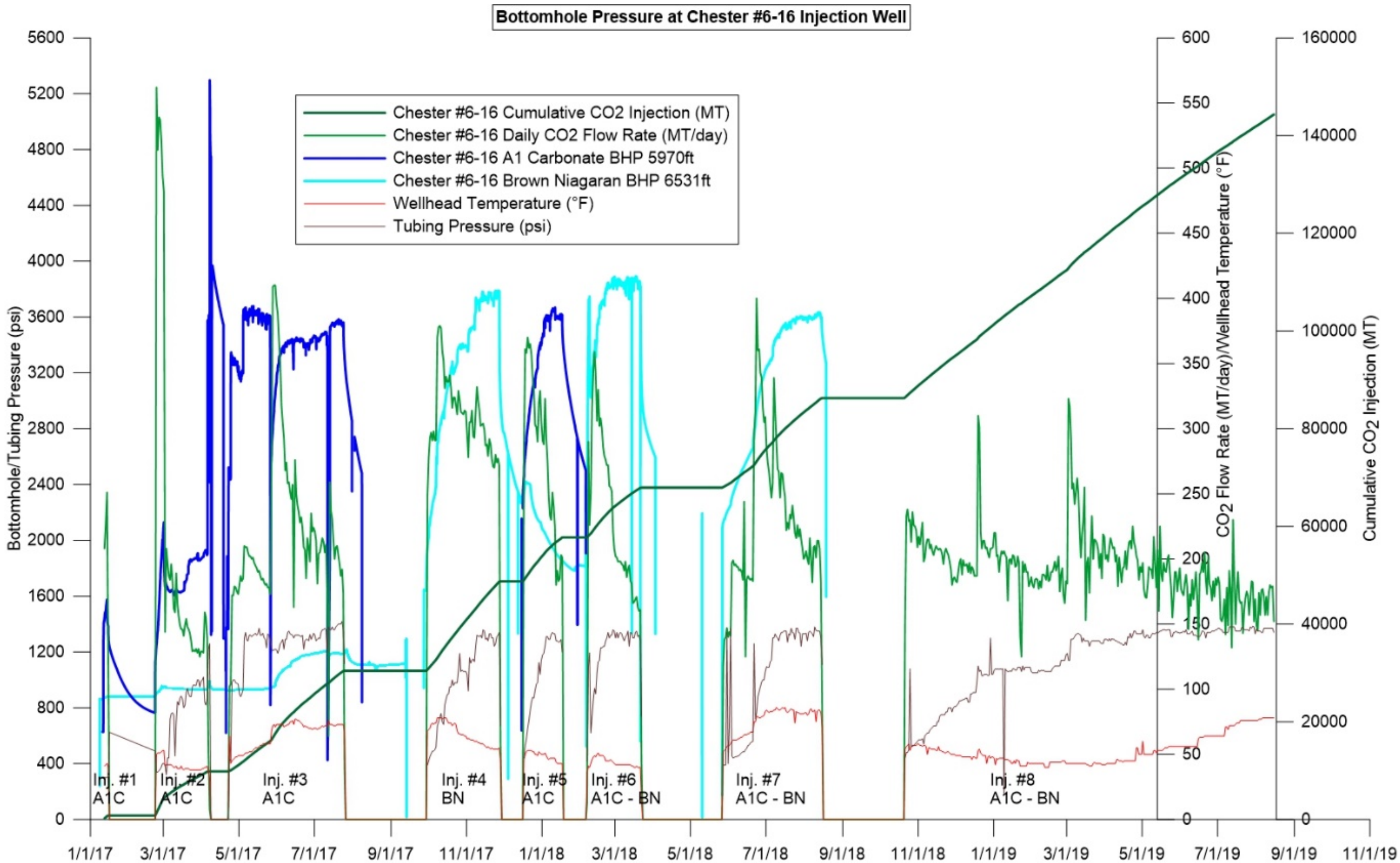


Figure 4-1. Injection history of Chester 6-16 injection well and bottomhole pressures observed in the A1 Carbonate (A1C) and Brown Niagaran (BN) Formations.

4.4 Injectivity of A1 Carbonate and Brown Niagaran Formations

Variability in relative injectivities can influence the quantity of CO_2 that can enter the reservoir through perforations. Therefore, it is important to determine the injectivity of the individual perforated intervals. Injectivity index is a parameter that describes injection capacity of a well. Water injection tests were carried out in September 2017 by isolating each of three perforated zones in the A1 Carbonate Formation and four perforated zones within the Brown Niagaran Formation. The injectivity index (bbl/day-psi) is the ratio of the water injection rate (bbl/day) divided by the difference in pressure (psi) before and after water injection.

Core Energy performed injectivity tests with injection of hot water by isolating each of the seven perforated zones of the Chester 6-16 injection well. Table 4-2 shows the results of these tests. The analysis shows that the injectivity of the perforated intervals varies significantly, even within a single formation. For example, for the A1 Carbonate, Perf #1 showed a very poor injectivity of 1.2 bbl/day-psi, while Perf #2 and Perf #3 were 21 and approximately 35 bbl/day-psi respectively. Similarly, calculated injectivity index for Perf #4, Perf #5 and Perf #7 in the Brown Niagaran Formation indicated poor injectivity (approximately 0.1 to 3.6 bbl/day-psi), while injectivity at Perf #6 was better at approximately 67 bbl/day-psi. This variability in relative injectivities can influence the quantity of CO_2 that can enter the reservoir through these perforations.

Table 4-2. Analysis of Hot Water Injectivity Tests at Chester 6-16 injection well.

	Zone	Start BHP psi	End BHP psi	Delta BHP psi	q BPM	J bbl/d/psi
A1 Carbonate	1	1,606.2	3,565.8	1,959.6	1.59	1.2
	2	1,519.0	1,642.0	122.9	1.79	21.0
	3	1,549.2	1,618.5	69.3	1.67	34.7
Brown Niagaran	4	1,559.1	4,101.9	2,542.8	0.34	0.2
	5	1,374.4	3,740.8	2,366.5	0.18	0.1
	6	1,289.0	1,328.6	39.6	1.84	66.9
	7	1,445.6	2,403.4	957.9	2.41	3.6

Since lateral drilling was completed in October 2018 and injection resumed, the last injection period (Table 4, injection period #8) has been the longest thus far (over 10 months). Compared to prior injection periods, the quantity of CO_2 injected (approximately 58,000 MT) also has been the most CO_2 injected thus far. At surface, the compressors at Chester 10 natural-gas processing facility (which supplies pure CO_2) is limited to ~1,400 psi. During prior injection periods, the tubing pressures rose rapidly, limiting the amount of CO_2 that could be safely injected. However, during the last injection period (#8), the tubing pressure gradually rose to about 1,300 psi in ~6 months and have held steady (1,300-1,350 psi) in response to lower rates of injection (on average, 190 MT/day).

Figure 4-2 below compares the injectivities for selected injection periods (#5 - #8); x-axis contains the parameter Q/q (cumulative injection Q, MMCF normalized to daily injection rate q MMCF/day) vs. the y-axis parameter dP/q (change in daily tubing pressures compared to starting tubing pressure (dP, psi) also normalized to daily injection rate q, MMCF/day). This plot shows that for the last injection period #8 (subsequent to drilling of laterals), the injectivity has improved substantially compared with prior injection periods.

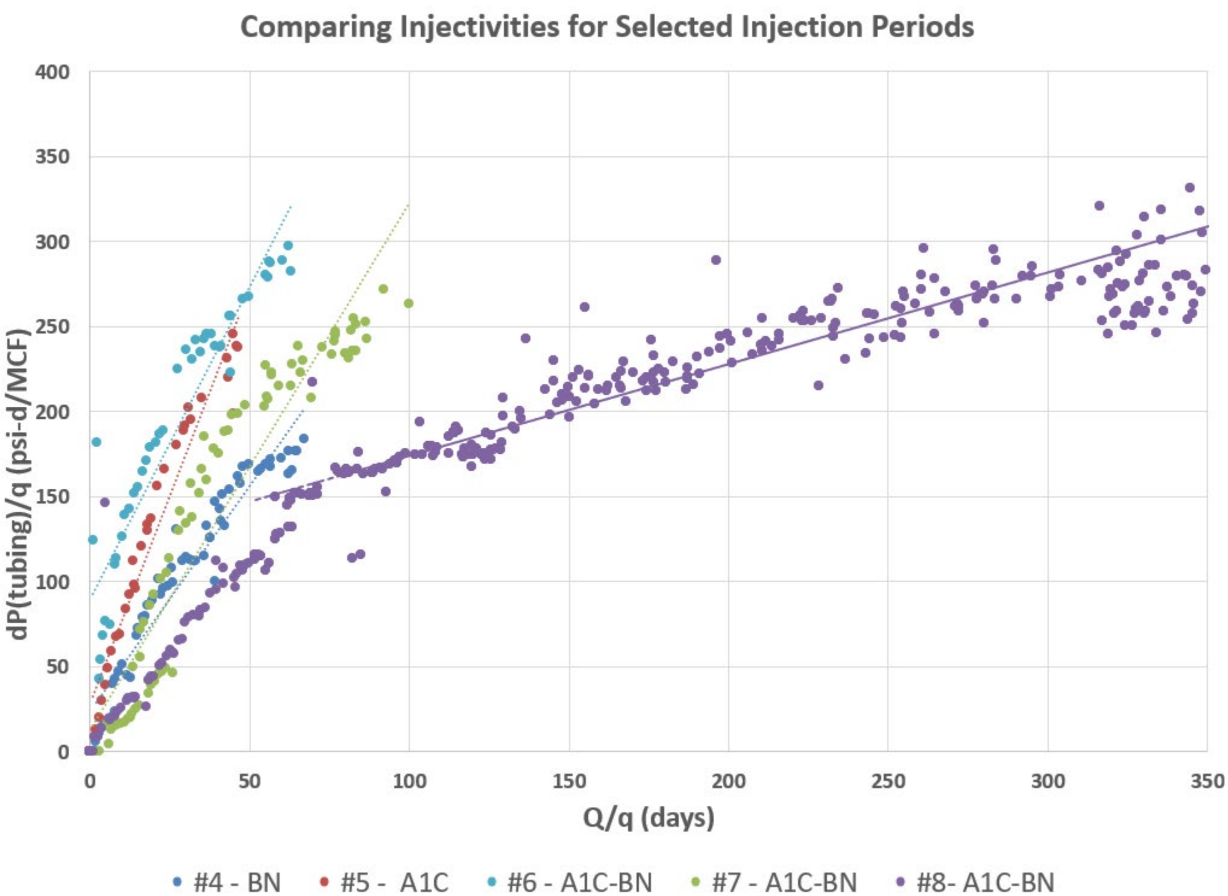


Figure 4-2. Injectivities of selected injection periods

4.5 Inferring Inflow Zones using DTS Data

This section evaluates the differences in injectivities of the two formations, cooling signatures near perforated zones from DTS data, and the warmback analysis to determine where the CO_2 is entering the target formation. Also, the DTS signature is analyzed above and below the perforated zones to determine if there was evidence for vertical migration along the injection wellbore. The inferences drawn from the warmback analysis are qualitative, and no attempt was made to numerically apportion quantities of CO_2 injection into various formations.

4.5.1 Depth vs. Temperature Profiles

Figure 4-3 is a plot of depth vs. temperature for three injection periods: injection period #2 when CO_2 was flowing into the A1 Carbonate Formation, injection period #4 (Brown Niagaran), and injection period #6 (both formations). In each instance, the DTS data represent temperatures approximately 24 hours after injection had resumed, allowing wellbore temperatures to stabilize in response to fluctuating flow rates. The relative locations of seven perforated zones (note top three perforations are in A1 Carbonate Formation) are shown as green horizontal bars, each representing a 10 ft. long perforated interval. The three injection periods were compared with initial baseline reference DTS temperatures (dark blue line) in February 2017 before main CO_2 injection (other than 804 MT during injection period #1 in January 2017).

Temperature profiles for these three injection periods suggest that the entire injection interval (i.e., interval encompassing all perforated intervals) experienced cooling in response to injection of cooler CO_2

(relative to reservoir temperature of approximately 95 to 100 °F), even if a single formation was the target of CO_2 injection. This type of coarse cooling signature (and the variability of injectivities) makes it difficult to predict exactly where CO_2 entered the reservoir. Additionally, temperature profiles at specific times do not provide information about the quantity of CO_2 injected through the various perforated zones.

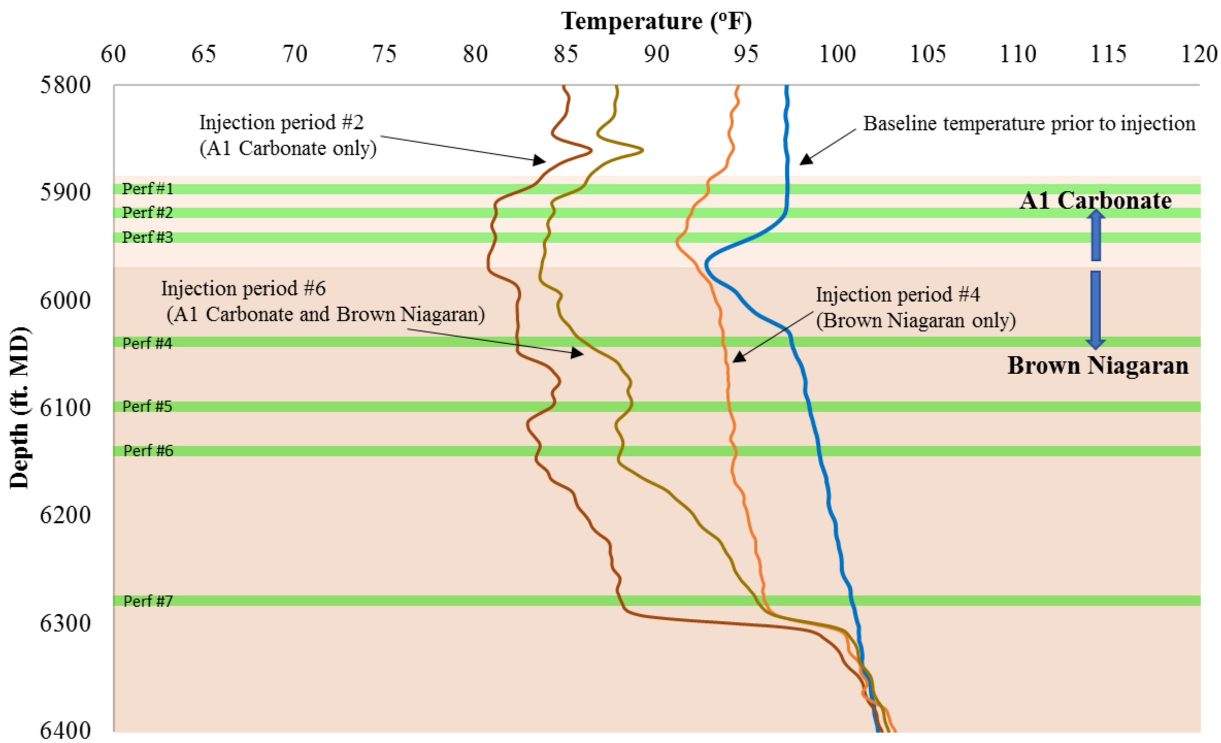


Figure 4-3. Snapshot of depth vs. temperature for selected injection periods after injection resumes.

4.6 Formation Warmback Analysis

Two types of analysis were done to discern flow distribution: an analysis of the temperature behavior during injection and analysis of the warmback behavior when injection ceased. Temperature behavior during injection shows where injectate moved within the wellbore, but it does not necessarily show where fluids entered the reservoir. This is because any given cooling or warming signal cannot distinguish between pressure changes due to flow within the wellbore and pressure changes due to CO_2 entering the reservoir. Warmback analysis (analyzing temperature warmback in depth and time in the period) after injection ceases allows inference of where fluids entered the reservoir. The depths where injection into the reservoir occurred will exhibit more cooling, and therefore will take longer to warm back to background temperatures after injection ceases. Appendix A includes a report by SageRider for the analysis of the DTS data for injection periods #2 through #6.

Figure 4-4 shows a composite waterfall plot of temperatures at the injection well across the entire injection period until August 15, 2019 when DTS data were last processed. Here, the blue colored zone represents cooler temperatures, while red colored zones indicate warmer temperatures. It should be noted that during the injection the entire wellbore cools, but when injection is shut, the shallower formations (B Salt, A2 Carbonate and A2 Evaporite) quickly revert to reference reservoir temperatures. Similarly, near the bottom of Brown Niagaran formation, below the bottom-most perforated zone #7 at approximately 6150 ft. MD shows no significant cooling indicating no migration of cooler CO_2, either during injection or the falloff period when injection is shut. This waterfall plot of temperature suggests that most injected CO_2 has remained within the target zone of injections, the A1 Carbonate and the Brown Niagaran formations.

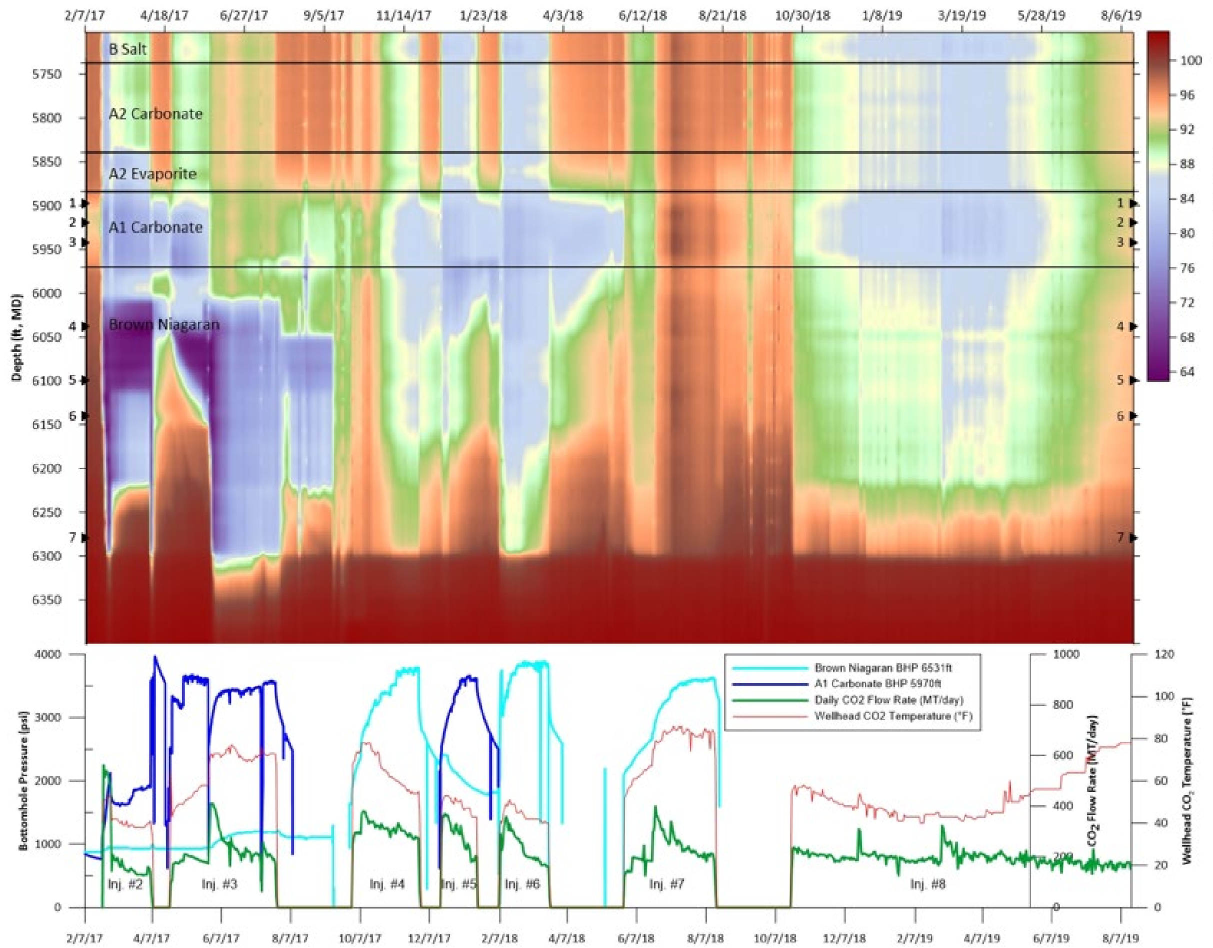


Figure 4-4. Waterfall plot of temperatures and bottomhole conditions in Chester 6-16 injection well

4.6.1 Warmback Analysis - Injection Period #2, A1 Carbonate

During injection period #2 (lasting 44 days between February 22 and April 6, 2017), 9,039 MT of CO_2 were injected at the Chester 16 reef. During this period, the target zone of injection was the A1 Carbonate Formation. The Brown Niagaran Formation was isolated from receiving CO_2 via a plug placed within injection tubing near the bottom of A1 Carbonate Formation. This injection period was followed by a falloff lasting 16 days.

Figure 4-5 shows a waterfall plot of this injection period until April 22, 2017, when period #3 resumed. Initially the injection rate is high at approximately 500 MT/day but then drops to 200 MT/day. During this period, the entire wellbore appears to cool between 5,700 – 6,300 ft., near the bottom of the Brown Niagaran Formation. Cooled depth moves downward, likely indicating displacement of a water level in the well. Cooling at the end of period #2 has proceeded to the depth of the deepest perfs (perf #7).

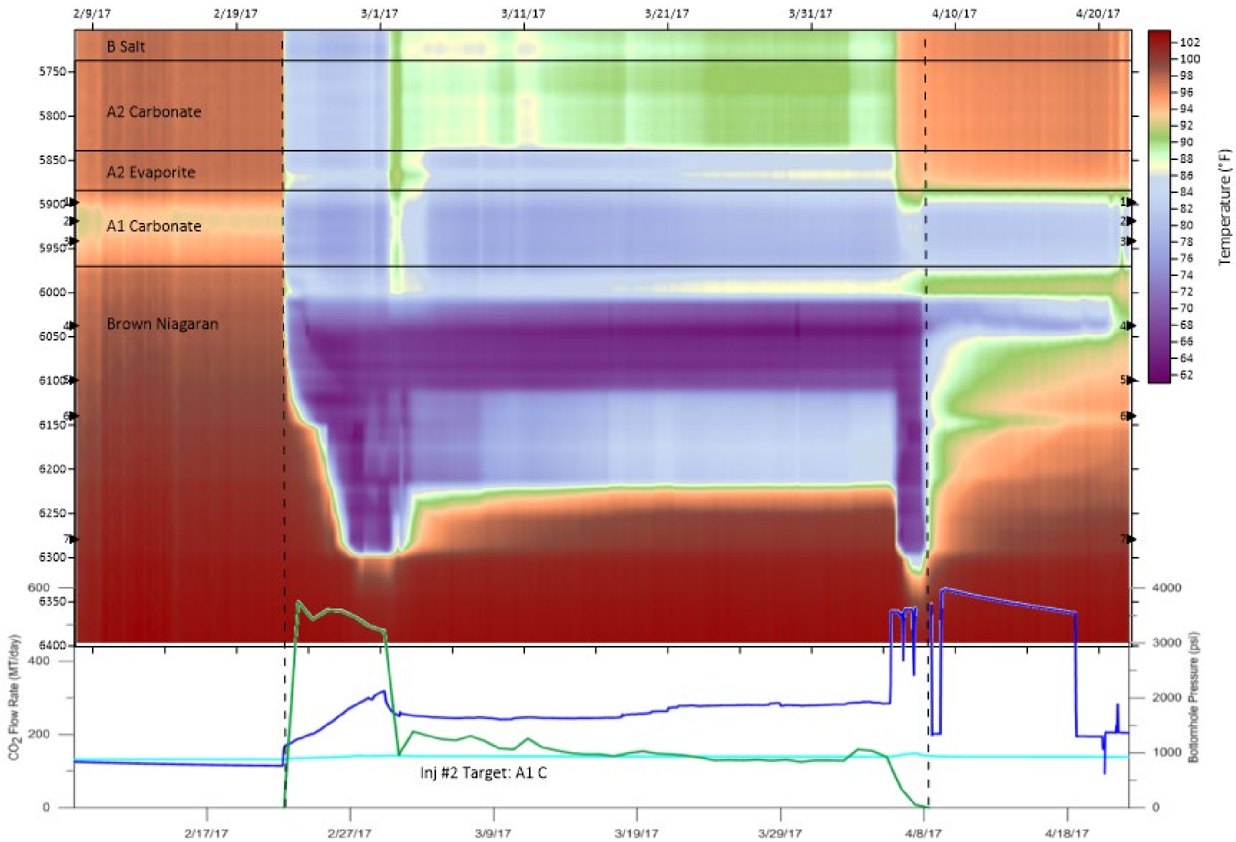


Figure 4-5. Waterfall plot of temperature for injection period #2.

Warmback analysis provides the most direct evidence of injection into the reservoir. Zones that are not a target of injection and are not impacted by the thermal effects of flowing injectate do not complicate the temperature signal. Therefore, warmback analysis identifies vertical zones that take longer to warmback. Reservoir zones that do take longer to warmback indicate zones that took more injection, and therefore were cooled more thoroughly. To view warmback effects, a differential temperature analysis is done. Instead of plotting raw temperatures, a plot of differential temperature (temperature at a given depth and time minus the temperature at that depth at the first time slice, usually at the end of injection) is made. This tends to accentuate the temperature differences and changes, which are useful to the analysis.

Figure 4-6 shows the differential temperature plot of injection period #2 after injection had stopped on April 6 and until April 22, 2017. This plot suggests that the overlaying formations such as the B Salt, A2 Carbonate and the A2 Evaporite quickly reverted to reference temperature. This suggests no vertical migration of cold CO_2 to these formations. Also, deeper into the Brown Niagaran formation, beneath perf #7, no appreciable cooling took place during injection. Also, the A1 Carbonate formation shows slowest warmback, suggesting significant cold injectate entered the reservoir through perf #1 through perf #3. The differential plot also suggests some injectate entered the reservoir near perf #4 and perf #6 (see areas marked with arrows in Figure 4-6) in the Brown Niagaran Formation, even though this was not the target zone of injection. Additional evidence of unintended migration is obtained by reviewing a slight increase in pressure (approximately 50 psi) in the memory gauges placed at the bottom of Brown Niagaran Formation (see circled area C#1 in Figure 4-1). While DTS does suggest specific pathways by which such unintended migration could occur, it is hypothesized here that CO_2 could enter deeper formation via leakage between the tubing plug, casing packer isolating the two formations, CO_2 migrating along vertical lengths between the production casing and the cemented area, and entering perforated zones of the Brown Niagaran Formation.

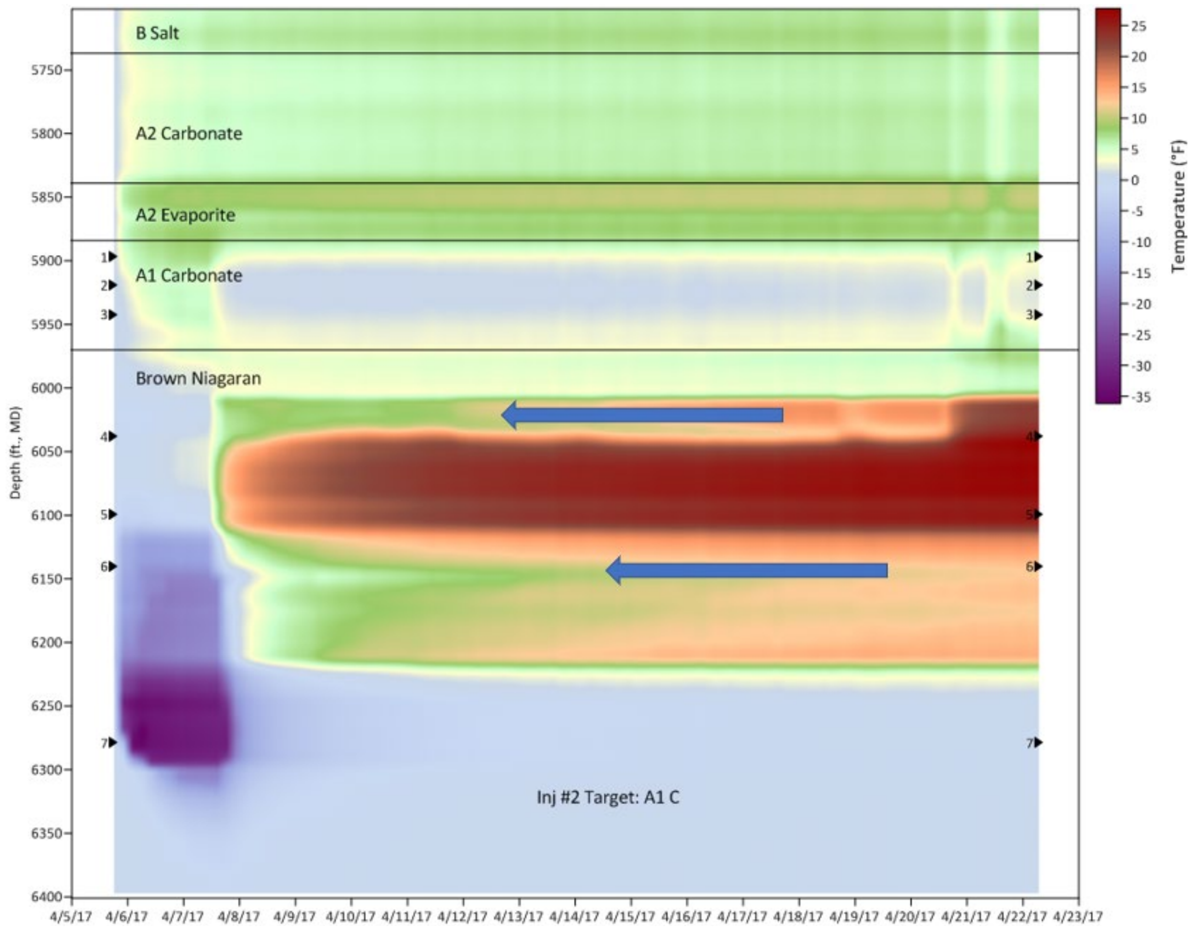


Figure 4-6. Differential temperature plot of injection period #2

4.6.2 Warmback Analysis - Injection Period #3, A1 Carbonate

Injection period #3 lasted 94 days between April 22 and July 24, 2017, during which 20,585 MT of CO_2 were injected into the A1 Carbonate at the Chester 16 reef. This was followed by a falloff period lasting 67 days, until September 29, 2017. Figure 4-7 shows the waterfall plot of temperatures during injection period #3. Initially during this injection period, injectate appears and cools the A1 Carbonate annulus and the upper Brown Niagaran annulus (until perf #6) slowly. However, when the injection rate nearly doubled around May 27, 2017, the injectate appeared to push the fluid level down in the Brown Niagaran annulus to the depth of perf #7 and cool the Chester 6-16 wellbore in the perforated interval between A1 Carbonate and Brown Niagaran Formation.

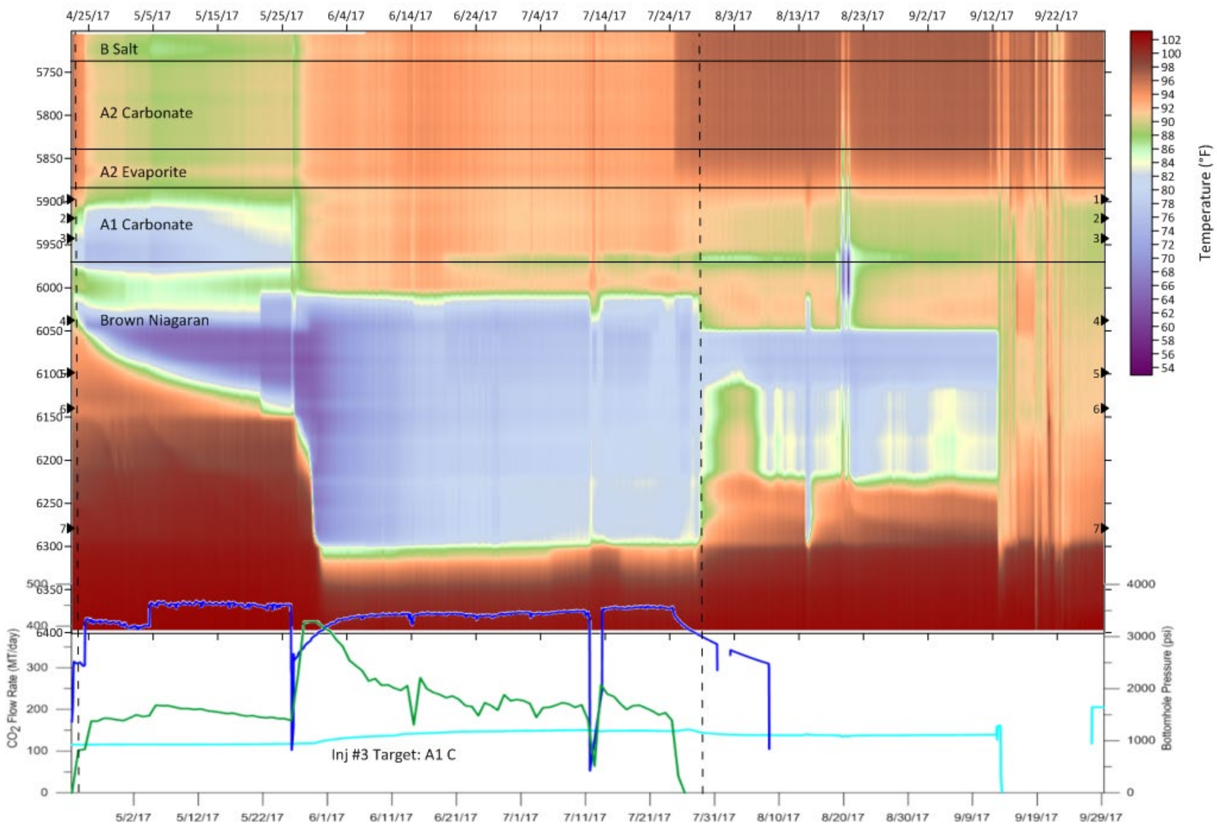


Figure 4-7. Waterfall plot of temperature for injection period #3

Figure 4-8 represents the differential temperature of the warmback after injection stopped on July 24, 2017, until September 29, 2017, when subsequent injection period #4 resumed. The overlaying layers above the A1 Carbonate Formation never cooled significantly during injection, and the relative uniform warmback suggests no fluid injection or migration vertically into these formations. Similarly, the deeper Brown Niagaran formation beneath perf #7 did not receive any CO_2.

Just prior to the rate change on May 27, 2017, Core Energy had performed some well workover activities involving injection of acid and adjustments to sliding sleeve. These workover activities make it difficult to interpret the DTS data. However, the waterfall temperature plot (Figure 4-8) above, suggests subsequent to May 27, most of the injection occurred in the deeper Brown Niagaran formation as opposed to the target injection zone in the A1 Carbonate Formation. Observations from the bottomhole memory gauges placed in the Brown Niagaran formation at the Chester #6-16 injection well show a sharp increase in bottomhole pressure of approximately 300 psi (see circled area C#2 in Figure 4-8), which suggests unintended migration took place in the Brown Niagaran Formation. The warmback analysis plot below shows a narrow band of cooling zone at the contact point between the two formations at 5,970', and near the perf #5 there appears to be slight initial warming followed by cooling. The warmback during injection period #3 is difficult to interpret. However, unintended injection appears to have taken place in the Brown Niagaran Formation.

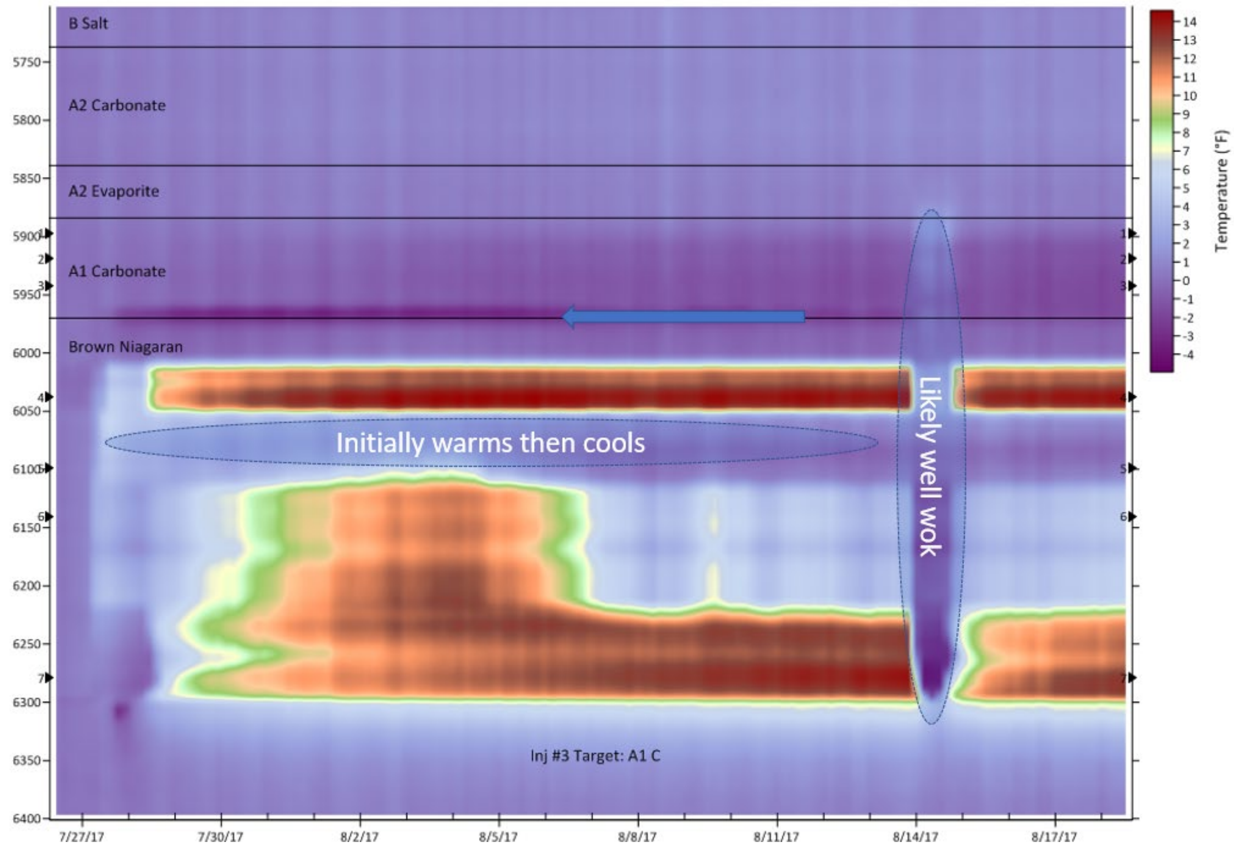


Figure 4-8. Differential temperature plot of injection period #3

4.6.3 Warmback Analysis - Injection Period #4, Brown Niagaran

During injection period #4, Core Energy targeted the Brown Niagaran Formation for injection. The well configuration was altered by removing the tubing plug between the A1 Carbonate and Brown Niagaran formations, and the sliding sleeve within A1 Carbonate was closed. This would enable CO_2 to flow past the A1 Carbonate and inject into the Brown Niagaran Formation only. As such, bottomhole memory gauges were placed within the Brown Niagaran Formation only. During this injection period of 59 days between September 29 and November 27, 2017, 18,314 MT of CO_2 were injected into the Brown Niagaran at the Chester 16 reef. This was followed by a falloff period lasting 19 days.

Figure 4-9 shows a waterfall plot of this injection period until December 16, 2017, when the subsequent period #5 resumed. When injection started on September 29, 2017, the CO_2 injected at surface was relatively warm (approximately 78 °F), thus the Chester 6-16 wellbore experienced subtle and slow cooling during injection. During second half of injection (around October 25 and later), the CO_2 was being injected a lot cooler (approximately 60 °F), and both the A1 Carbonate and Brown Niagaran annuli experienced pronounced cooling. During warmback, slower warmback was seen at perfs #1 - #6 indicating possible injection at all these perforated zones. Perfs #2 - #3 (A1 Carbonate) and perf #4 (Brown Niagaran) appear to show the slowest warmback, implying these took the most injection.

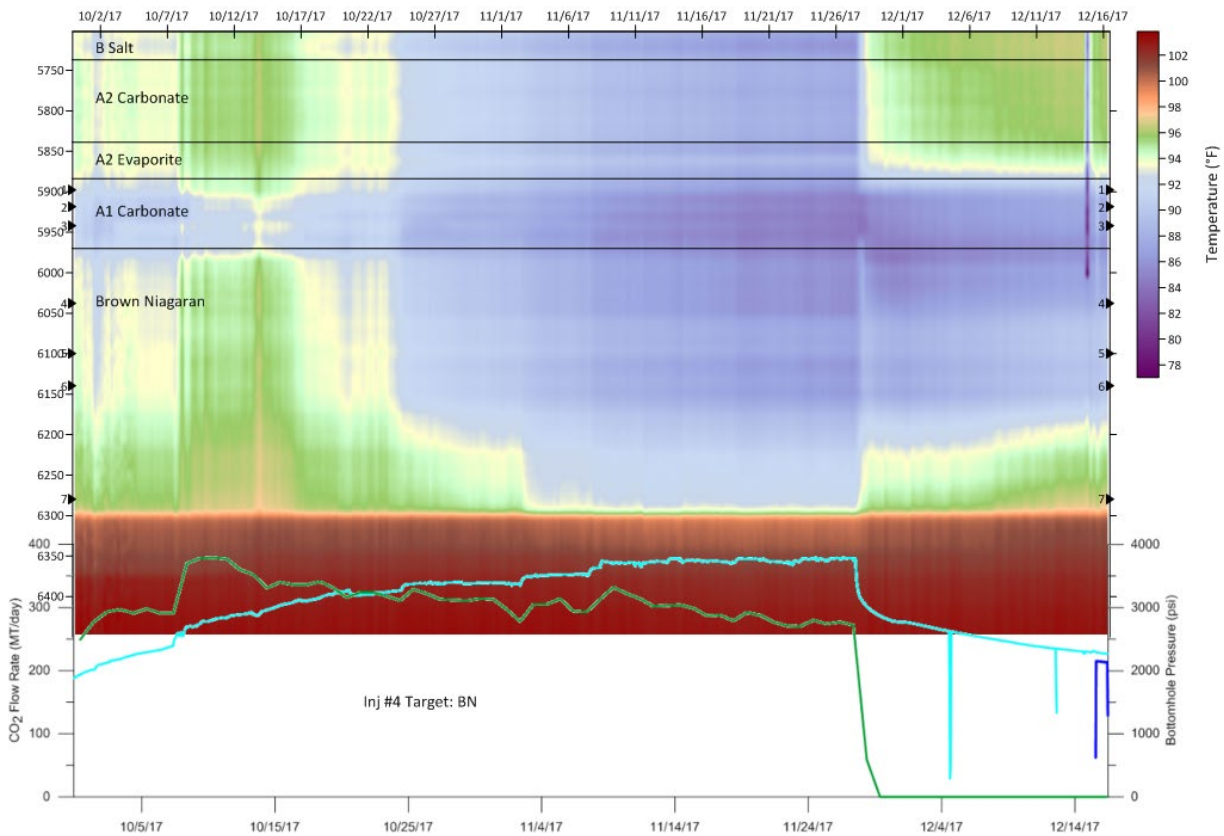


Figure 4-9. Waterfall plot of temperature for injection period #4

Figure 4-10 represents the differential temperature of the warmback after injection stopped on November 27, 2017 until December 16, 2017, when injection resumed. The falloff period is brief at 19 days. The relatively quick warmback in the overlaying B Salt, A2 Carbonate and the A2 Evaporite formations suggests CO_2 was not injected to these zones. Similarly, the zone at perf #7 and deeper within Brown Niagaran Formation did not cool appreciably during injection, and this zone continues to be isolated from CO_2 injection. The differential temperature analysis suggests slow warmback zone is prevalent at the formation contacts near 5,970 ft. MD (below perf #3 in A1 Carbonate to perf #7 in Brown Niagaran). Thus, it can be concluded that bulk of the CO_2 was injected in the target Brown Niagaran Formation, with some injection within A1 Carbonate as well. It is possible that CO_2 injected in deeper Brown Niagaran Formation migrated vertically within the reservoir into the more permeable A1 Carbonate Formation.

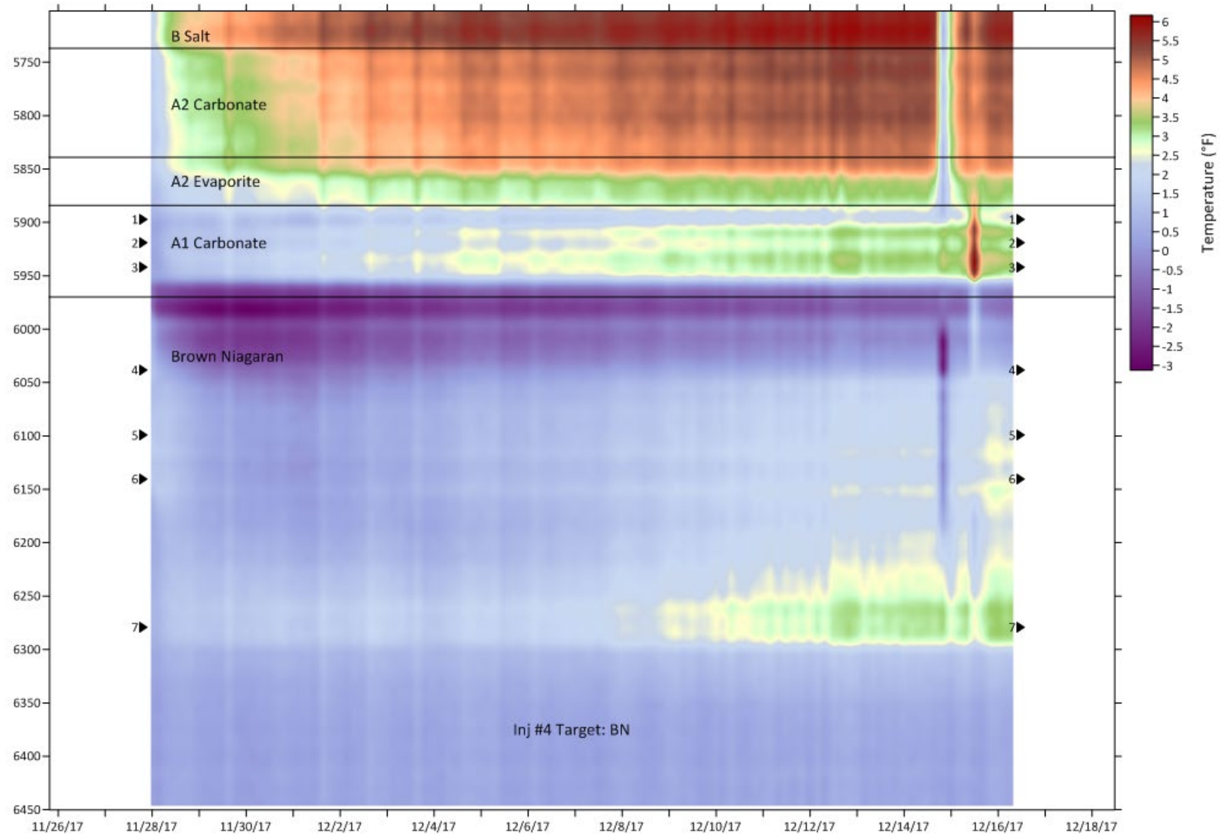


Figure 4-10. Differential temperature plot of injection period #4

4.6.4 Warmback Analysis - Injection Period #5, A1 Carbonate

During injection period #5, Core Energy targeted the A1 Carbonate Formation for injection. During this injection period of 31 days between December 16, 2017 and January 16, 2018, 9,010 MT of CO_2 were injected. This was followed by a falloff period lasting 20 days.

Figure 4-11 shows a waterfall plot of this injection period until February 5, 2018, when injection period #6 resumed. During this injection period, the bulk of the CO_2 at surface was injecting relatively cool at approximately 50 °F, resulting in wellbore cooling in the annular space within the A1 Carbonate Formation. Some lesser cooling also occurred in the Brown Niagaran annulus and appeared to reduce during the first half of the injection period. Warmback showed persistent cooling at perfs #1 - #3, implying those perforated zones took most of the injection and that there was negligible injection into the Brown Niagaran Formation.

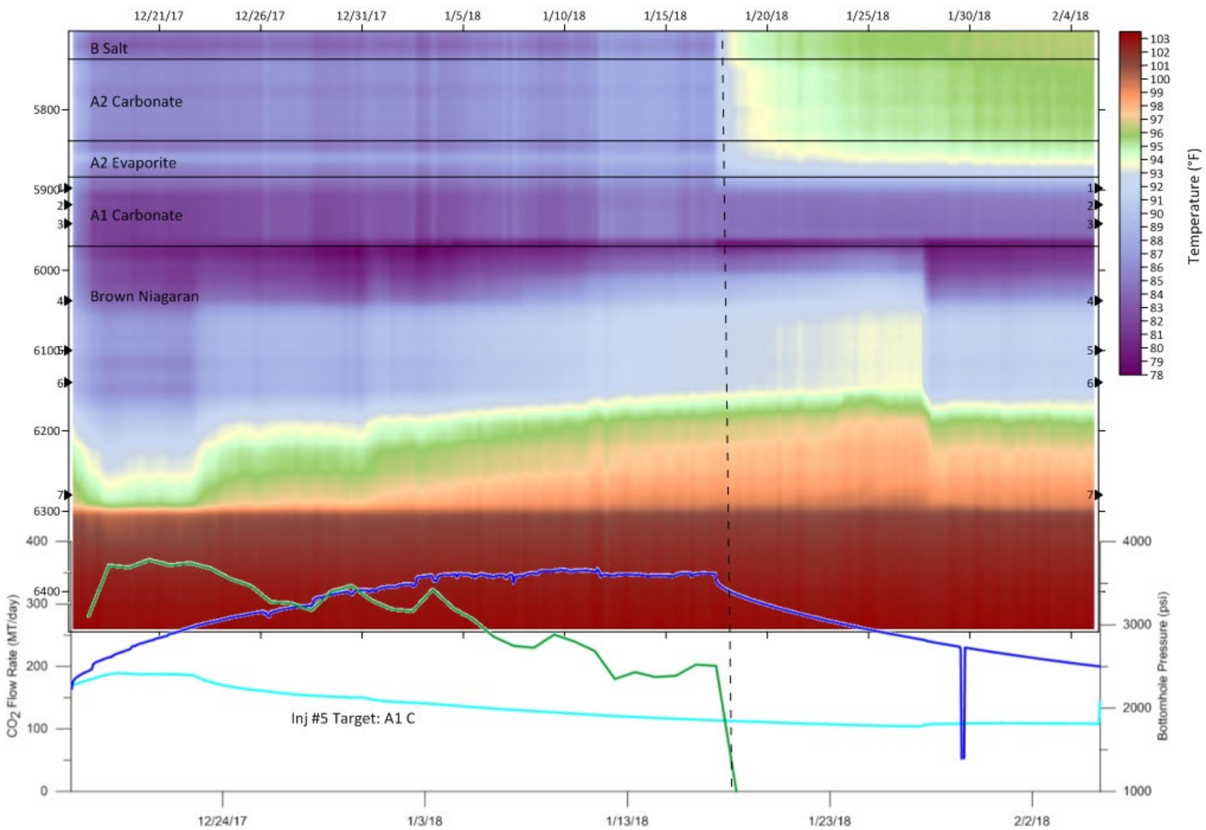


Figure 4-11. Waterfall plot of temperature for injection period #5

Figure 4-12 shows the differential temperature waterfall for the injection period #5's warmback. The overlaying layers have relatively fast and uniform warmback, indicating no fluid injection into formation as would be expected (this is the zone above perforated zone in A1 Carbonate). The persistent cooling zone and lack of warmback in the A1 Carbonate (perf #1 to #3) indicates most of the CO_2 entered this zone. The differential temperatures within the Brown Niagaran Formation is difficult to interpret as there is no apparent warmback suggested here. However, the waterfall plot above only suggests a cooling zone above perf #5, while near perf #6 and #7, the temperatures are relatively warm, indicating lack of presence of CO_2. Finally, below perf #7 there is no warmback as this zone did not cool appreciably during injection.

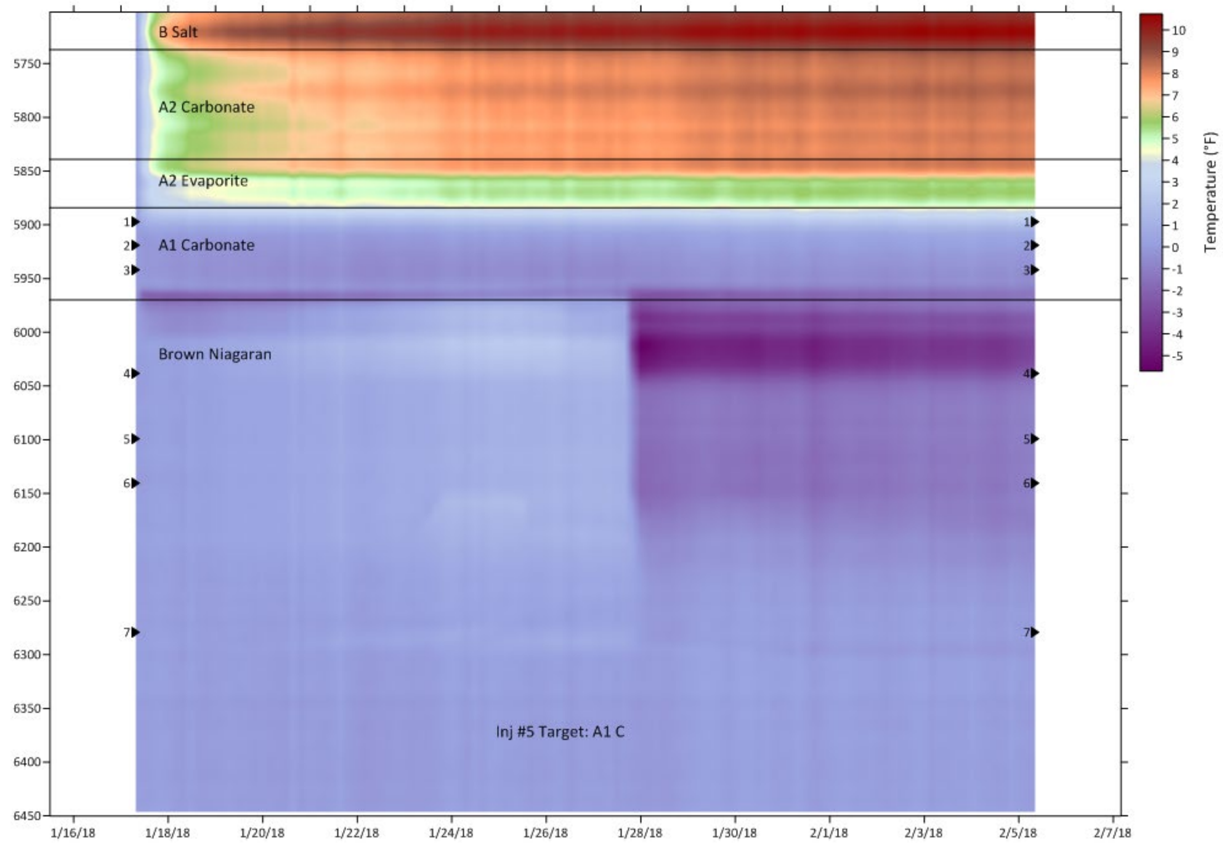


Figure 4-12. Differential temperature plot of injection period #5

4.6.5 Warmback Analysis - Injection Period #6, A1 Carbonate and Brown Niagaran

During injection period #6, Core Energy targeted the combined A1 Carbonate and Brown Niagaran formations for injection. During this injection period of 44 days between February 5 and March 21, 2018, 10,178 MT of CO_2 were injected. This was followed by a falloff period lasting 66 days.

Figure 4-13 shows a waterfall plot of this injection period until May 26, 2018, when the subsequent injection period #7 resumed. During injection, the character of the waterfall plot is similar to injection period #6 (Dec ‘17-Jan ‘18) targeting the A1 Carbonate.

During injection, strongest cooling was seen in the vicinity of perfs #1 - #3 (A1 Carbonate). There was cooling also in vicinity of perfs #4 - #6 (in the Brown Niagaran) and to a lesser and sporadic extent at perf #7. However, over the injection, that initial cooling in the Brown Niagaran started to warm, which could indicate some of the injectate went in the wellbore but not necessarily into formation in appreciable amounts. Once injection ceased, the Brown Niagaran perforated zones warmed back more quickly than the A1 Carbonate zones, indicating that the A1 Carbonate took the bulk of the injection. Some injection may have entered the Brown Niagaran Formation at a lesser amount than the A1 Carbonate.

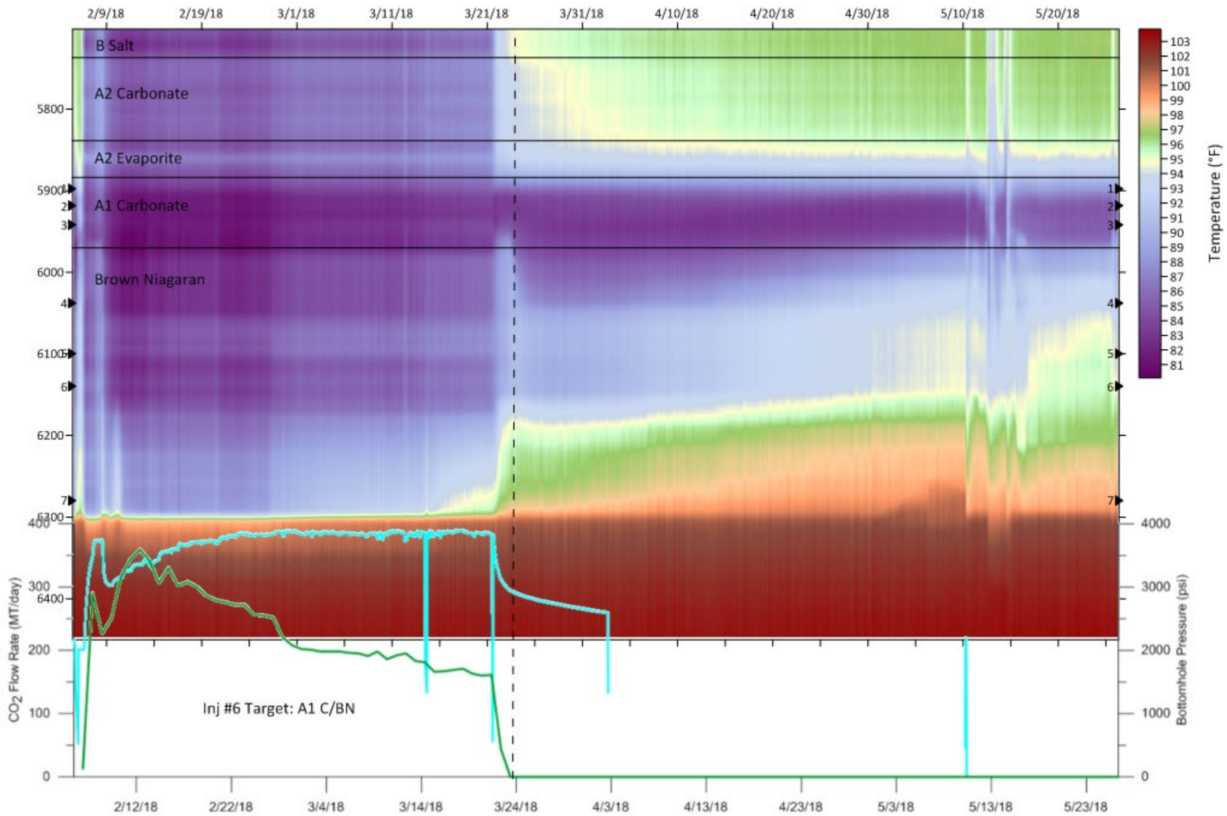


Figure 4-13. Waterfall plot of temperature for injection period #6

Figure 4-16 shows the differential temperature waterfall for the injection period #6's warmback. The overlaying layers have relatively fast and uniform warmback, indicating no fluid injection into formation. Also, at perf #7 in the Brow Niagaran, the temperature warmed almost immediately as soon as injection stopped, and formation beneath this perforated zone did not cool appreciably during injection, indicating no injection took place near deeper formation. The persistent cooling zone and lack of warmback in the A1 Carbonate (perf #1 to #3) indicates most of the CO_2 entered this zone. The differential temperatures within the Brown Niagaran Formation is difficult to interpret as there is no apparent warmback suggested here. However, the waterfall plot above only suggests a cooling zone above perf #5, while near perf #6 and #7, the temperatures are relatively warm, indicating lack of presence of CO_2.

The perforated zones #1 - #3 in the A1 Carbonate continued to remain cool after injection stopped, indicating that this formation took most of the injection. In the Brown Niagaran, near perf #4 there was somewhat slower warmback compared to zones near perf #5 and #6, indicating some injection took place near the top of the Brown Niagaran Formation but less than in A1 Carbonate.

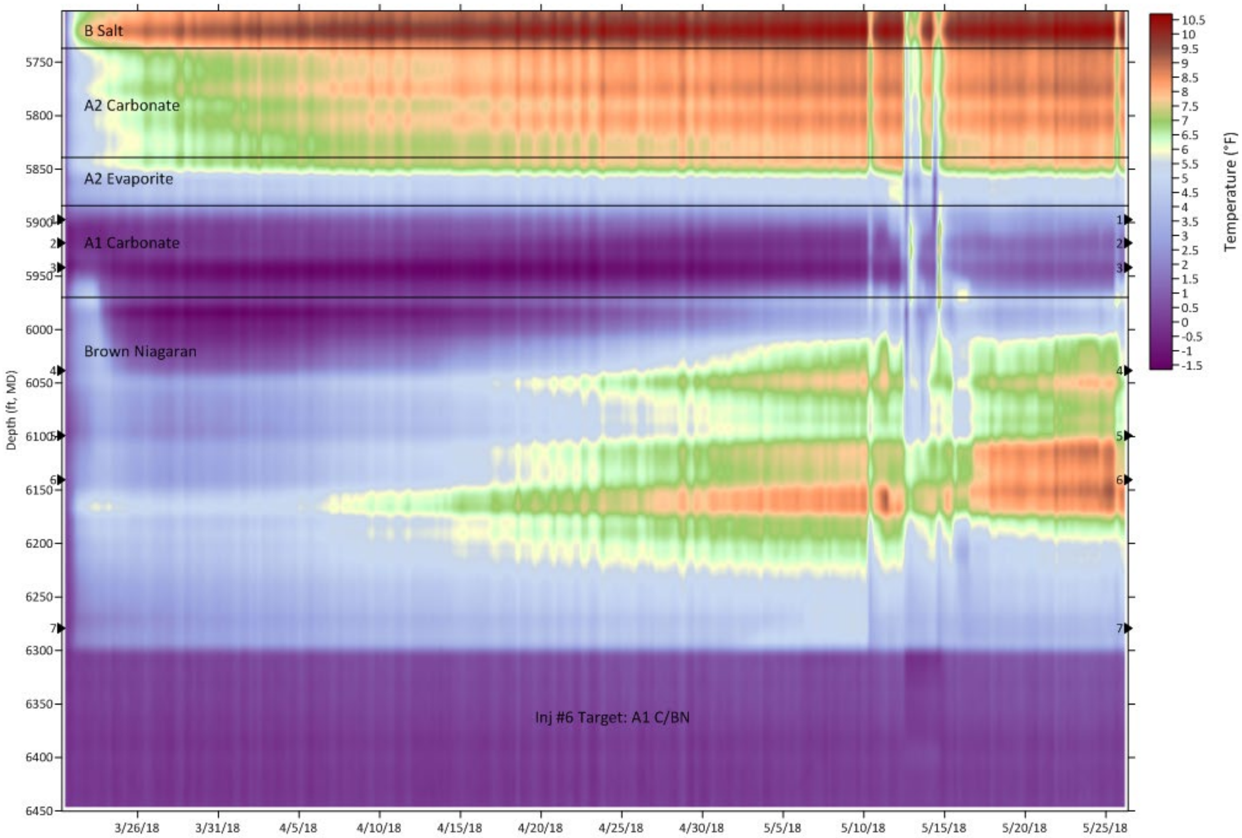


Figure 4-14. Differential temperature plot of injection period #6

4.6.6 Warmback Analysis - Injection Period #7, A1 Carbonate and Brown Niagaran

During injection period #7, Core Energy targeted the combined A1 Carbonate and Brown Niagaran formations for injection. During this injection period of 80 days between May 26 and August 14, 2018, 18,320 MT of CO_2 were injected. This was followed by a falloff period lasting 66 days.

Figure 4-17 shows a waterfall plot of this injection period until October 20, 2018, when injection period #8 resumed. The profile of temperatures in this injection period is peculiar—until June 18, 2018 the entire wellbore until perforated zone #7 cooled. Figure 4-1 in Section 4.3 also confirms that the initial surface temperature of the injected CO_2 is quite cold at approximately 50 – 65 °F, resulting in wellbore cooling as the cold CO_2 entered intended target formations (combined A1 Carbonate and Brown Niagaran). Beginning on June 20, 2018, Core Energy increased the rate of injection from approximately 180 MT/day to over 300 MT/day. This rate change and the relatively poor injectivities of the Chester 6-16 perforated zones warmed the incoming CO_2 temperature to above 75 °F at surface, resulting in warming of the wellbore. The injection well continued to *resist* the high rates of injection, resulting in higher bottomhole pressures and increase in the wellhead temperature of injected CO_2 (approximately 85 °F) at surface (see Figure 4-1 in Section 4.3). This relatively warmer CO_2 is entering the reservoir (approximately 98 °F) at temperatures close to the native reservoir fluids (approximately 100 °F). Subsequently, there was slight cooling (approximately 94 °F) within the reservoir zone until injection stopped on August 14, 2018.

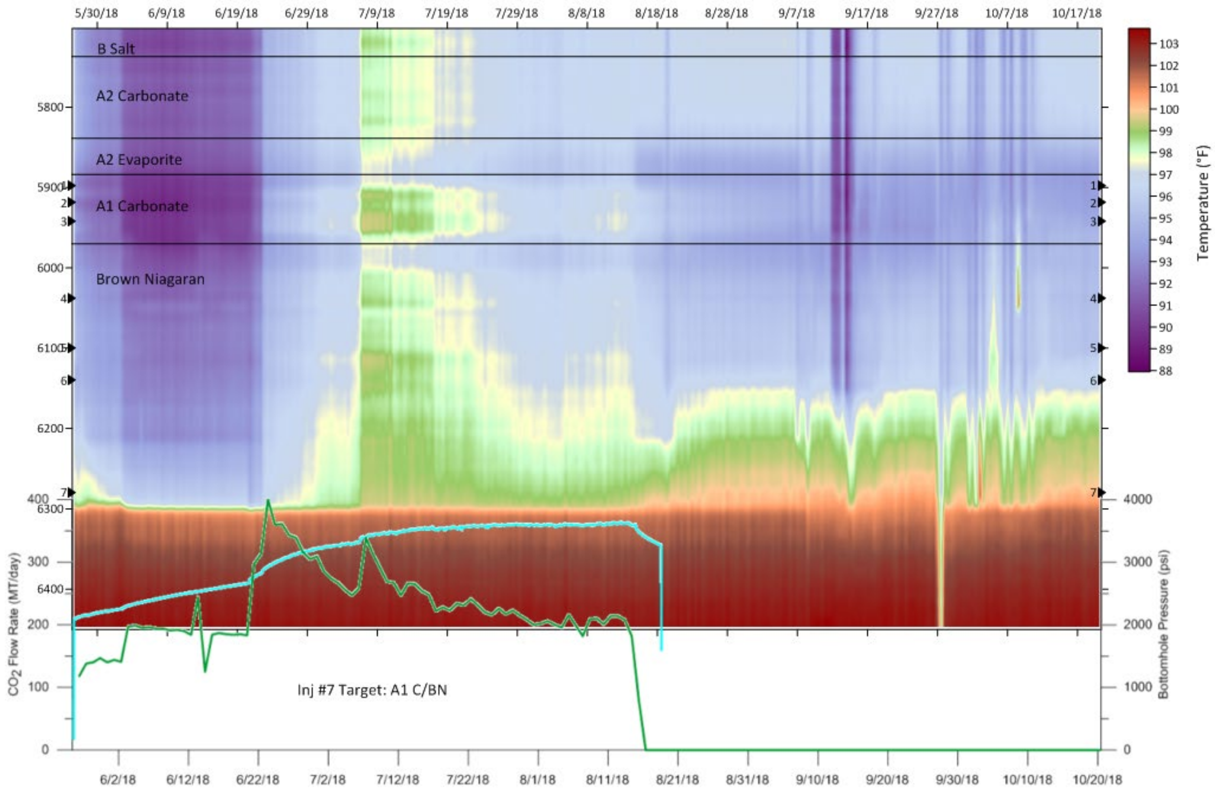


Figure 4-15. Waterfall plot of temperature for injection period #7

Figure 4-16 shows the differential temperature waterfall for injection period #7's warmback. The overlaying layers have relatively fast and uniform warmback, indicating no fluid injection into formation. Also, at perf #7 in the Brow Niagaran, it warmed almost immediately when injection stopped. The formation beneath this perforated zone did not cool appreciably during injection, which indicates no injection took place at the bottom of Brown Niagaran Formation. The relative cooling zone is mostly observed between perforated zones between perf #1 through perf #5, and to a lesser extent near perf #6 in Brown Niagaran. It can be surmised that bulk of the CO_2 injection took place within the A1 Carbonate and top perforated zones of Brown Niagaran formations. The vertical blue streams of temperatures at various times is likely due to well workover activities within the falloff period.

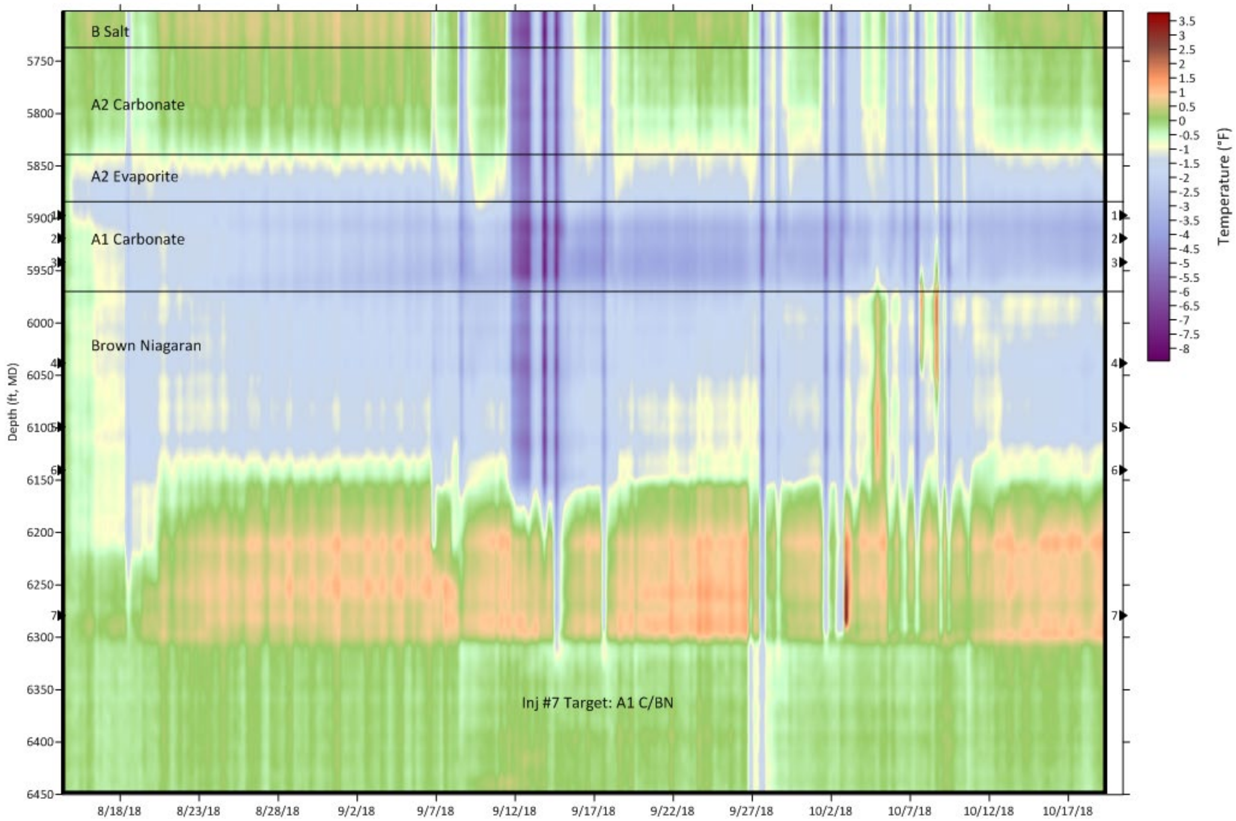


Figure 4-16. Differential temperature plot of injection period #7

4.6.7 Warmback Analysis - Injection Period #8, A1 Carbonate and Brown Niagaran

During the last injection period #8, Core Energy again targeted the combined A1 Carbonate and Brown Niagaran formations for injection. This injection period began on October 19, 2018 and was the longest period (300 days) since lateral drilling between October 1-9, 2018 (see Section 3.2.1). As of August 15, 2019 (when DTS data were last collected), 58,226 MT of CO_2 were injected. This period does not have falloff data as injection was continuing as of August 15, 2019 and therefore does not have the differential (warmback) temperature analysis available.

Figure 4-17 shows the waterfall plot of this injection period until August 15, 2019. The coolest zone (approximately 85 °F) appears be near perfs #1 - #3, indicating the bulk of the CO_2 is entering A1 Carbonate Formation.

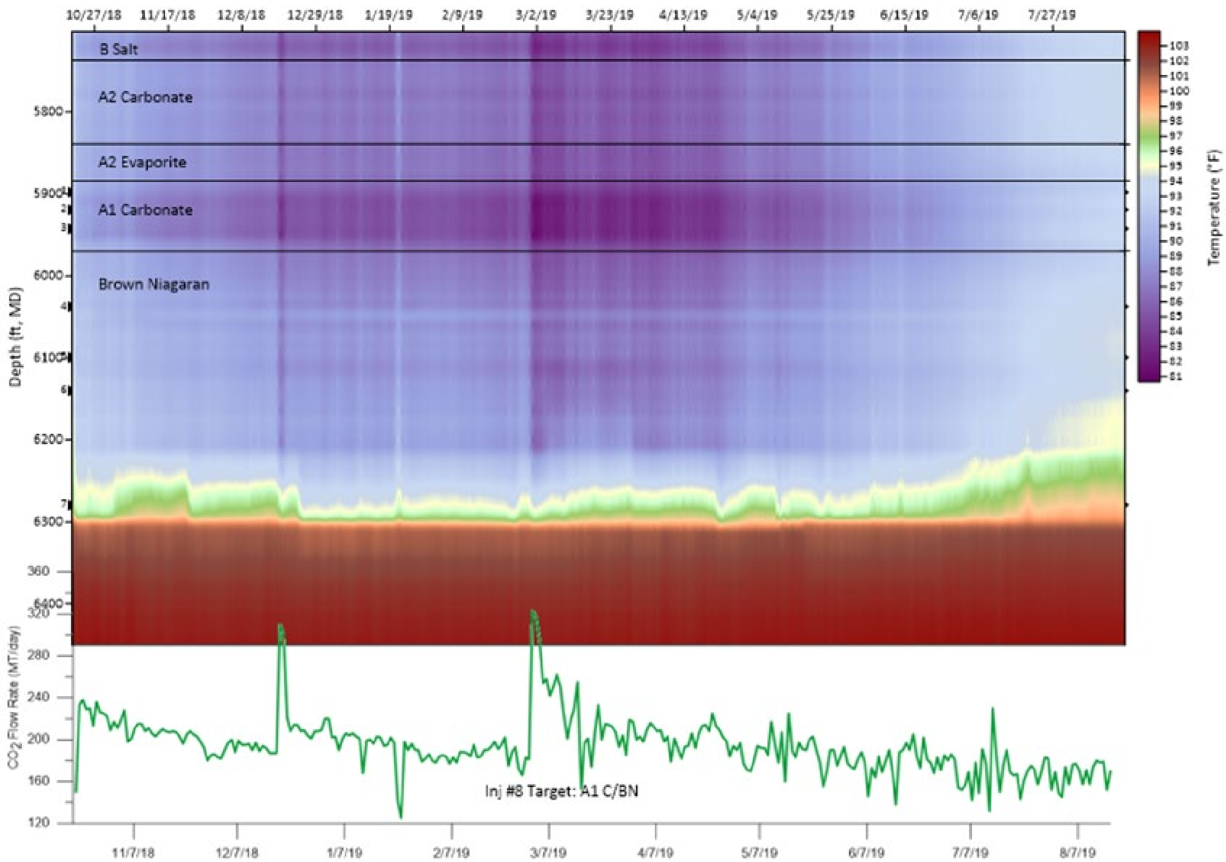


Figure 4-17. Waterfall plot of temperature for injection period #8

4.6.8 Observations from Warmback Analysis

The composite waterfall plot (Figure 10) of seven injection periods (#2 - #8) suggests the entire wellbore along the vertical lengths of the Chester #6-16 injection well cools in response to flow of cold CO_2 in the injection tubing (relative to warmer formation temperatures). Additionally, the plot indicates that the wellbore either cools or warms in response to fluctuating temperature of the injected CO_2 (see red line indicating wellhead CO_2 temperature in Figure 10). The surface temperature of injected CO_2 varies between 40 - 60 °F (either seasonally or due to rate changes). However, bulk of the cooling is observed along the A1 Carbonate and top of the Brown Niagaran, the two target formations for injection.

The individual warmback analysis presented for each of the injection periods suggests that the bulk of the injected fluids enter the formation(s) of interest. This is shown by continuation of the cooling zone in the target formation(s) after injection has stopped. When injection stops, formations above and below the injection depths quickly revert back to their respective reference temperature, while the injection zones (A1 Carbonate and/or the Brown Niagaran) continue to maintain temperatures indicative of incoming injected fluids. The warmback analysis also suggests unintended migration of CO_2 into the Brown Niagaran Formation during early injection periods (#2 and #3) when the target formation was the A1 Carbonate Formation.

In order to increase public confidence in integrity of CCS operations, DTS can be a powerful monitoring technique for determining exactly where in the formation is the injected fluid entering the reservoir (especially when an injection well is perforated at multiple zones) as well as whether out-of-zone fluid migration occurs. Also, for CO_2-EOR operations, DTS can provide insights into operational strategies for improving the injection performance.

4.7 Detecting Arrival of the CO_2 Plume at the Chester #8-16 Monitoring Well

In addition to assessing objectives (as discussed in Section 4.6) regarding migration of CO_2 vertically along the Chester #6-16 injection wellbore and out within the reservoir, the third objective of this task was to determine if DTS can detect arrival of CO_2 at the Chester #8-16 monitoring well (approximately 1,100 ft. distance from the injection well). As cold CO_2 is injected into the reservoir and mixes with warmer reservoir fluids, slight cooling is expected to occur further out within the reservoir as the CO_2 plume migrates towards the monitoring well. The native reservoir fluids at depths of A1 Carbonate Formation near the Chester #8-16 well are typically at approximately 104 °F, gradually rising to approximately 107 ft. deeper in the Brown Niagaran Formation. The reef geology (see Section 3.1) also suggests that the A1 Carbonate Formation is more porous and permeable than the Brown Niagaran Formation. As such, we expect the CO_2 front to move preferentially in the A1 Carbonate Formation than in the Brown Niagaran Formation.

4.7.1 DTS Observations at Monitoring Well

Figure 4-18 shows a waterfall plot of temperatures at the monitoring well (depths on y-axis between 5,500 and 6,200 ft. MD vs. time on x-axis). The plot shows DTS data since January 1, 2018, since prior to that time no discernable temperature fluctuations were detected by the DTS installed in the monitoring well. A small cooling signature (approximately 0.5 °F) was first observed in early March 2018, which further cooled by approximately 9 °F (compared to reference reservoir temperature of approximately 104 °F) at the end of December 2018. This cooling signature (see the dark blue/violet color band in Figure 4-18) persists throughout the 17-month period until August 15, 2019, when DTS data were last compiled. The cooling signature is centered around 5,885 ft. in the A1 Carbonate Formation. This suggests that the cold CO_2 front first arrived at the A1 Carbonate formation at monitoring well in March 2018, continued to cool with peak cooling occurring in December 2018, and warmed somewhat since then. It is noteworthy that the thermal pulse lags the arrival of pressure pulse. The Chester 8-16 monitoring well and the Chester 6-16 injection well are separated at bottomhole by approximately 1,100 ft. Figure 4-19 below shows that the pressure pulse first arrived at the Chester 8-16 (A1 Carbonate) during January 2018, approximately 11 months after injection began in February 2017. Meanwhile, the thermal pulse is detected by the DTS during March 2018, suggesting a 3-month lag between the pressure pulse and the thermal pulse.

This DTS trend suggests not only the detection of arrival of CO_2 plume in the A1 Carbonate Formation, but preferential movement of CO_2 within the A1 Carbonate, as compared to the Brown Niagaran Formation. This is true even though injection periods #6, #7 and #8 (between February 5 and August 15, 2018) targeted the combined A1 Carbonate and Brown Niagaran formations for injection. Warmback analysis presented in Section 4.6 also suggests more of the injected CO_2 was taken into the A1 Carbonate Formation, as opposed to perforated zones of the Brown Niagaran Formation.

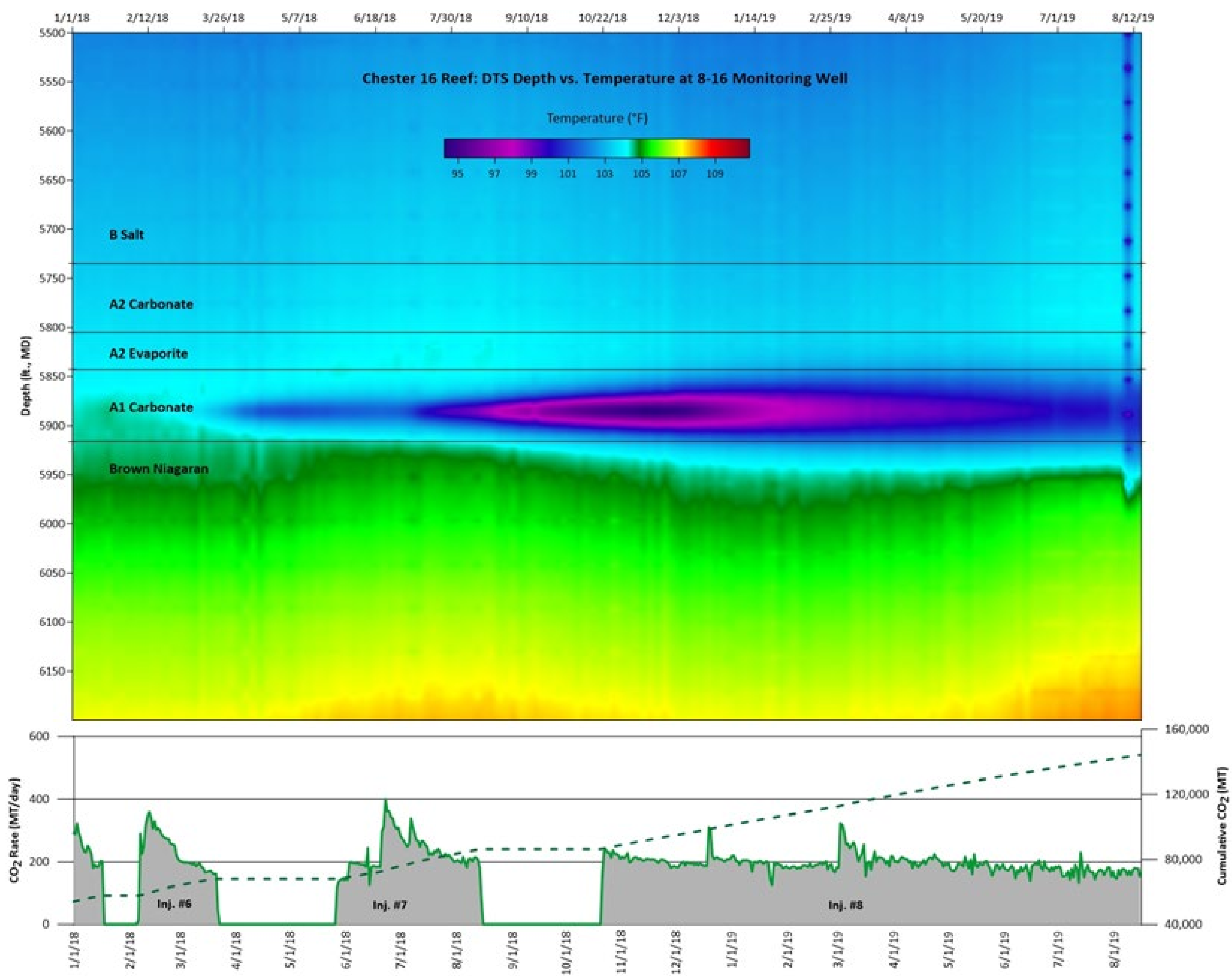


Figure 4-18. Waterfall plot of temperatures in the Chester 8-16 monitoring well.

4.7.2 Behind-Casing Pressure and Temperature Sensors at Monitoring Well

In addition to DTS, there are pressure and temperature data from five discrete sensors permanently installed behind-casing at the Chester 8-16 monitoring well (see Figure 4-19). Generally, the pressure in the Niagaran reefs follow an approximately 0.5 psi/ft. pressure gradient. Despite the initial pressure drift (observed soon after sensors began recording pressure and temperature in 2017), the pressure is lower in the shallowest sensor in A2 Carbonate (5,752 ft.), followed by A1 Carbonate (5,865 ft.), and at three depths (5,932, 6,079, 6,182 ft.) within the Brown Niagaran formations. As the injection activity increases within the Chester #16 reef, the pressure sensors in A1 Carbonate (blue line) and A2 Carbonate (orange line) record significant pressure buildup compared to the three pressure sensors in the Brown Niagaran Formation. Until January 2018, approximately 57,000 MT of CO_2 had been injected in the reef, and pressure in the top two formations begin to cross over the pressure in the deeper Brown Niagaran Formation. This pressure trend would suggest preferential propagation of pressure, and thus movement of CO_2 plume in A1 Carbonate Formation compared to the deeper Brown Niagaran Formation. The pressure in the A2 Carbonate appears to track pressure in the A1 Carbonate, likely due to communication along the vertical section of the Chester 8-16 wellbore between the casing and the cemented portion of the well.

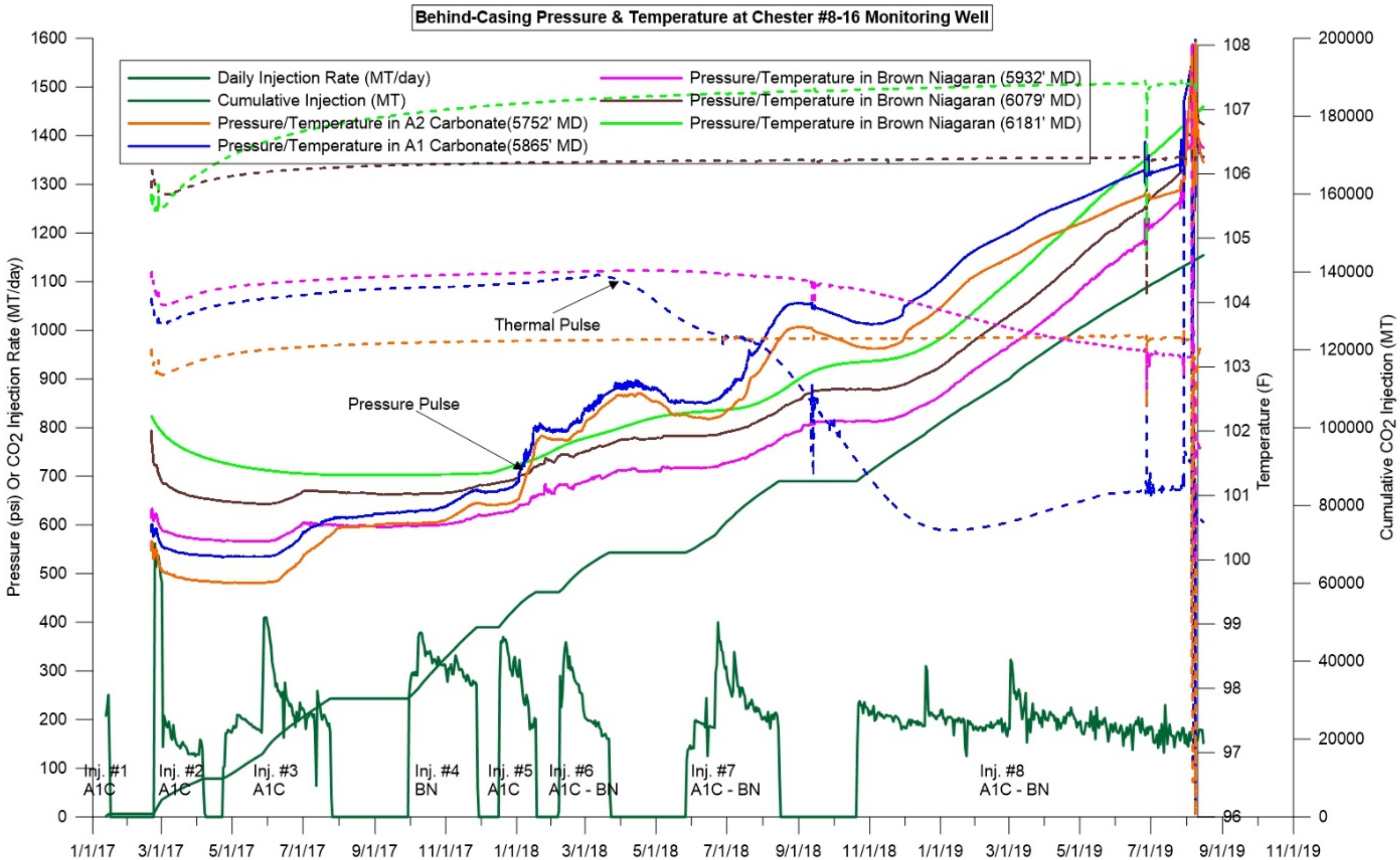


Figure 4-19. Behind-casing pressure and temperature at Chester 8-16 monitoring well

The A1 Carbonate Formation sensor, which records the highest-pressure increase, is also the zone of observed cooling by the DTS system. Figure 4-20 shows a plot of differential temperatures in the behind-casing sensors at A1 Carbonate (5,865 ft.) and top of the Brown Niagaran Formation (5,932 ft.). These sensors have observed some movement of temperature compared to sensors at other depths, where temperatures have held steady over time. Here, the plot shows the difference in temperature (Delta-T) from reference temperature at those depths on August 1, 2017. An initial cooling signature was first observed in March 2018 (blue dotted line) in the sensor located in the A1 Carbonate Formation. The cooling signature in the behind-casing sensor continued and peaked at approximately 100.5 °F (a drop of approximately 3.5 °F from reference temperature of 104 °F) by December 2018. Correspondingly, the DTS also observed an initial zone of cooling in the A1 Carbonate Formation (approximately 70 ft. interval between 5,850 ft. to 5,920 ft.) in March 2018 (see Figure 4-19 during injection period #6). The DTS also observed an expanding cooling zone by approximately 9 °F drop about 20 ft. below the behind-casing sensor at approximately 5,865 ft. MD in the A1 Carbonate Formation. The sensor located at the top-most zone in Brown Niagaran (5,932 ft. MD) indicates only slight cooling of approximately 1 °F to approximately 103 °F (reference formation temperature 104 °F) by August 15, 2019 when DTS data was compiled. Meanwhile, temperatures in the shallower A2 Carbonate Formation (5,752 ft. MD) and the two sensors in the Brown Niagaran Formation (6,079 and 6,181 ft. MD) remained flat, indicating no cooling was detected by the behind-casing sensors at those depths.

By early March 2018 (near the end of injection period #6), Core Energy had injected approximately 67,000 MT of CO_2 and nearly 13 months had elapsed since CO_2 was first injected in January 2017. The pressure trends (behind-casing sensors) combined with the temperature trends in the DTS and behind-casing sensors suggest presence of CO_2 in the A1 Carbonate Formation. By August 15, 2019, 144,476 MT of CO_2 was injected, and approximately 23 months had elapsed since the injection first began.

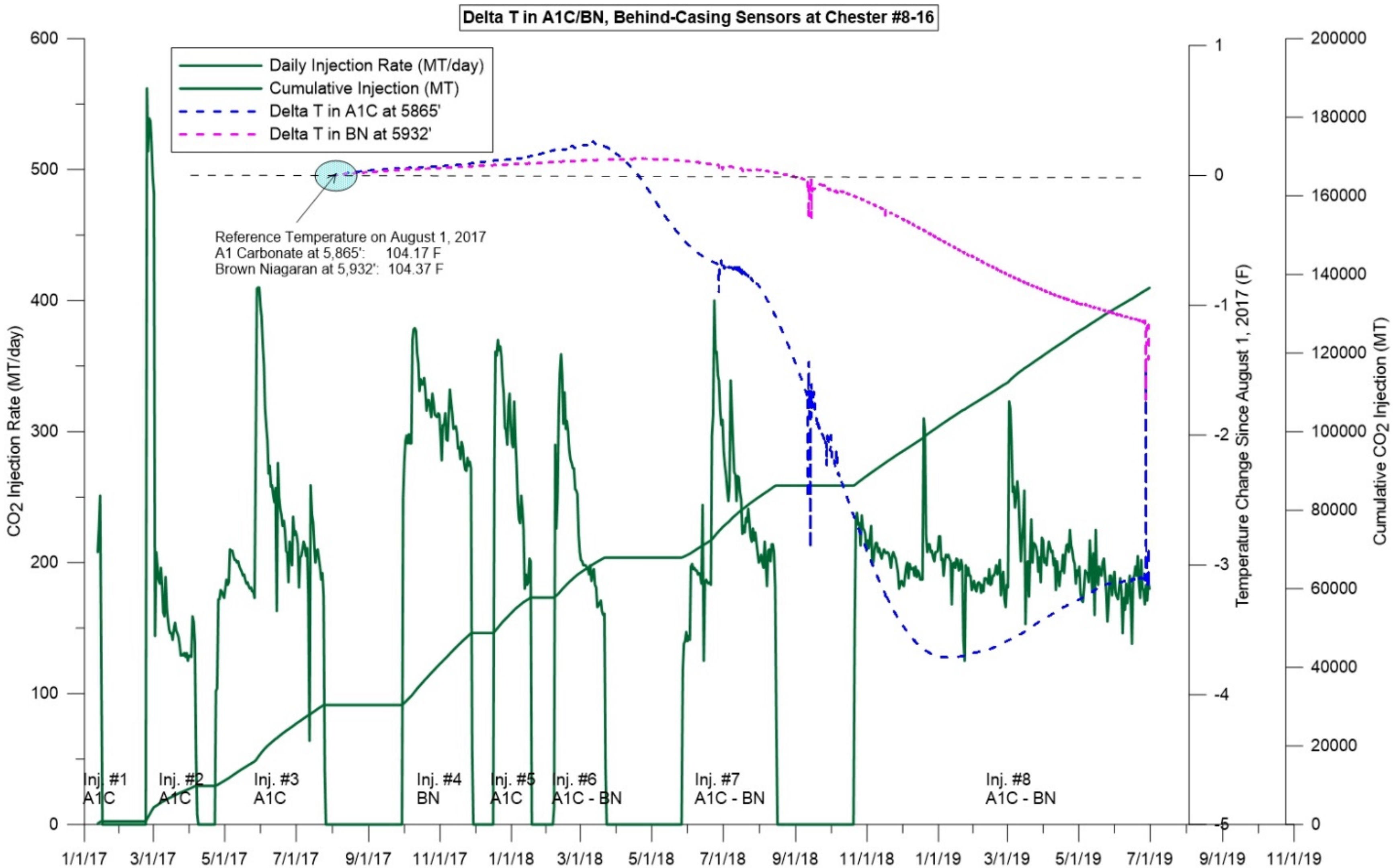


Figure 4-20. Behind-casing temperature differentials (Delta T) in A1 Carbonate and Brown Niagaran Formations at Chester 8-16 monitoring well

4.7.3 Corroboration with Other Data Sources

Two additional parameters affected by CO_2 flow were evaluated to corroborate the DTS response at the monitoring well— gas saturation and wireline temperature log. In non-isothermal injection systems, where cold fluid is being injected into a warmer formation, a thermal discontinuity is created within the formation behind the saturation discontinuity (between the injected and in-situ fluids), and the limits of pressure propagation (Bratvold and Horne, 1990). The pressure disturbance arrives first at the monitoring well, followed by a saturation front at a slightly colder temperature compared to in-situ conditions. Finally, the peak thermal disturbance arrives reflecting injected fluid conditions.

As part of the monitoring plan for the Chester 16 field, a baseline PNC log was run in the Chester 8-16 monitoring well in February 2017 prior to the start of injection. A repeat PNC log was run in the Chester 8-16 well in June 2018 after over a year of injection. The PNC tool measures the ability of an element to capture thermal neutrons and generates a log of this value, known as the thermal neutron capture cross section, or sigma. It is an interpreted quantity and is compared to referenced values of common downhole fluids and formation matrices. For more information on this method of data collection and analysis, reference the 'Pulsed Neutron Capture for monitoring CO_2 Storage with Enhanced Oil Recovery in Northern Michigan' report submitted as a topical report to DOE under the MRCSP project (Conner, et al., 2020). A higher sigma value equates to a greater ability of an element to capture, or absorb, the neutrons. Formation brines and oil all have distinctive sigma values that can be used to determine fluid saturations at various depths surrounding the borehole. Initial Sigma measurements show a notable change (increase) in sigma between repeat and baseline measurements within the A1 Carbonate Formation. This suggests that gas saturation has increased within this interval (sigma cannot distinguish CO_2 from methane, so this response could indicate an increase in either/both gases). Figure 4-21 displays all independent measurements in the Chester 8-16 monitoring well by depth.

Initial observations of discrete behind-casing pressure sensors indicate pressure buildup within the A1 Carbonate Formation as early as January 2018. Baseline and repeat PNC logging also show a potential saturation change within the A1 Carbonate Formation, which suggests the CO_2 plume has reached the monitoring well within the A1 Carbonate Formation. Additionally, a wireline temperature survey was run in the monitoring well on September 27, 2018 to confirm depth and temperature observations of DTS. Results from the wireline temperature survey indicate a zone of cooling of approximate same thickness and magnitude as the DTS survey (Figure 4-21, panel 4), within the A1 Carbonate Formation. Based on available pressure and gas saturation changes, cooling observed by DTS, and the wireline temperature log, a CO_2 front is observed to have arrived at the monitoring well in the A1 Carbonate Formation.

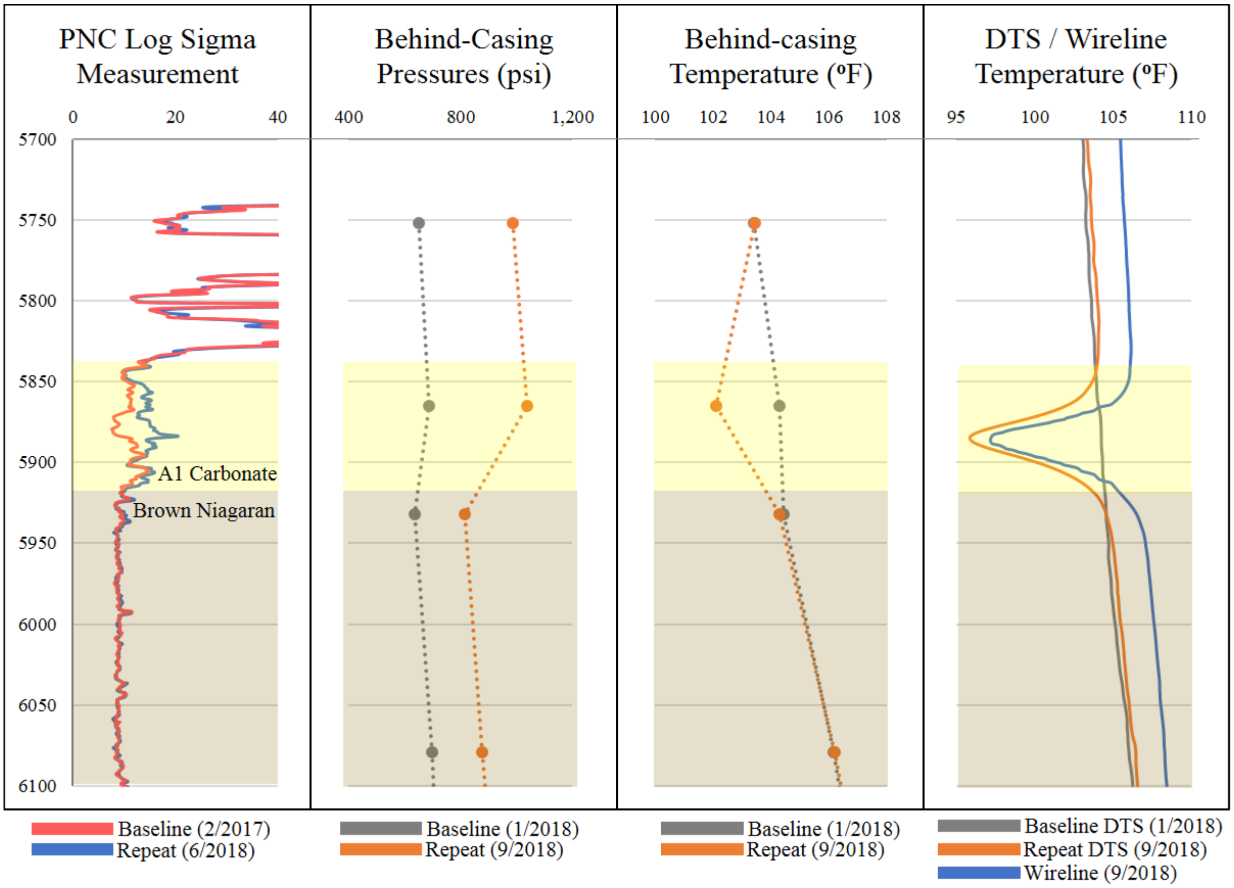


Figure 4-21. Baseline and repeat measurement from PNC well logging (panel 1), behind-casing pressure and temperature sensors (panels 2 and 3), and DTS data with the wireline temperature survey (panel 4).

4.7.4 CO_2 Arrival Summary

Arrival of CO_2 at the monitoring well (within A1 Carbonate Formation) is successfully detected using three parameters affected by CO_2 flow viz., increase in pressure, changes to gas saturations, and the decrease in temperature. DTS is able to successfully detect a temperature signature of arriving cold CO_2 front in March 2018, approximately 14 months after injection first began. The cooling signature continues to expand across the A1 Carbonate and the top of the Brown Niagaran formations as additional CO_2 is injected at the Chester 6-16 injection well. Thus, DTS can be a novel method of monitoring CO_2 injection activities of CCS operations when results of temperature data are analyzed along with additional lines of evidence. DTS can help with both assessing the direction of fluid flow (vertically or in the plane of fluid migration) as well as detecting arrival of CO_2 front at monitoring well(s).

5.0 Conclusions

Oil and gas operators use DTS for a variety of applications. One of the most common examples is the use of DTS for monitoring and detecting fluids in an open borehole or behind casing. Leaks can occur at along many points in a completed well and affect the borehole pressure or the cement integrity if leakage occurs in the casing. DTS can locate these by detecting temperature anomalies in the well (Bucker and Grosswig, 2017). Operators also use DTS to locate the top of hardening cement and prove integrity of the well (Bucker and Grosswig, 2017). To improve production, operators use DTS to verify flow paths and estimate flowrate in the reservoir. During waterflooding or steam flooding, the temperature profile can be used to characterize complex fluid movement, estimate velocity of fluid flow, or detect steam breakthrough at observation wells (Smolen and van der Spek, 2003; Yamate, 2009). Because temperature is a function of formation properties, DTS can be used as a tool to characterize a reservoir formation and record a temperature gradient (Wang, 2012; Bucker and Grosswig, 2017).

Applications of DTS for CO_2 injection operations are primarily associated with monitoring the movement of CO_2 and its containment within the reservoir. The Energy and Environmental Research Center (EERC), as part of the Plains CO_2 Reduction (PCOR) Partnership, used DTS to enhance the capabilities of a permanent downhole monitoring system by gathering temperature data at 1m intervals to create a temperature profile. Their overall objectives were to maintain appropriate injection rates to maintain reservoir integrity and enable storage performance evaluations (Hamling and Wildgust, 2015). The Southeast Regional Carbon Sequestration Partnership (SECARB) used DTS in an onshore well in the U.S. Gulf Coast region to monitor CO_2 flow at the inter-well scale and detect migration into the overburden. The study observed a general cooling trend as CO_2 moved through the reservoir, but the results were inconsistent and could not be validated due to severe instrument drift (Nuñez-Lopez et al., 2014). At one CO_2 storage demonstration site in Korea, DTS was used to control and improve the well completion process (Lee et al., 2018), but no subsurface monitoring of CO_2 has occurred yet.

This task demonstrates three practical uses of DTS data in a CO_2-injection context. Results show that warmback analysis is a useful tool for determining where the CO_2 is entering the reservoir from the injection well and can also help corroborate whether true zonal isolation occurs within the wellbore. This analysis is limited as the warmback provides circumstantial evidence but is not a lone indicator of reservoir injectivity zones. The nature of CO_2 migration vertically along the injection wellbore can also be ascertained based on the analysis of warmback periods. Relatively quick warmback above and below the perforated intervals indicates that there was no unintended CO_2 migration outside of target formations. Finally, it was shown that DTS detected the arrival of the CO_2 front at the monitoring well, in conjunction with corroborating pressure, gas saturation, and wireline temperature logging. A cooling signature began to appear within the monitoring well in March of 2018 after initial pressure increases were measured within the A1 Carbonate Formation.

The data in this report covers a period up to August 2019 with a series of injection and fall-off periods. The field activity during remaining 2019 and 2020 consisted of a fall-off period, followed by a period of sustained injection to sufficiently pressurize the reservoir. This was followed by the addition of perforations the reservoir zone in the monitoring well during March 2020 to convert this well to a dual production and monitoring use. The data to evaluate the outcome of the CO_2-EOR production phase were still being collected and will be analyzed in the future.

The DTS analysis presented here and static and dynamic reservoir modeling discussed separately in “MRCSP Integrated Modeling Report” has been crucial for Core Energy’s operational and production planning. The waterfall plots and warmback analysis of Chester 6-16 injection well identifies where exactly is the CO_2 is entering in the formation. The waterfall plots of DTS signatures at the Chester 8-16 monitoring well detects the arrival of CO_2 plume in the A1 Carbonate formation. Additionally, the pressure signals observed at multiple depths at the monitoring well allows us to understand vertical migration of fluids in the reservoir. Separately, in the integrated modeling report, Battelle discusses in detail the static earth model (SEM) and the dynamic reservoir/numerical model that was constructed to capture the complex fluid flow behaviors occurring in the hydrocarbon reservoir during CO_2 injection.

In conclusion, based on the field observations in this study, the use of fiber optics based DTS systems in CCS or CCUS environment (such as CO_2-EOR) can be strongly considered as part of the suite of options for monitoring CO_2 injection and flow. DTS can be used for detecting presence of CO_2 within target zones of injection and for detecting arrival of CO_2 plumes at monitoring wells. With the advancement of technology, we can also expect that combination of DTS with similar fiber optics based distributed pressure sensing applications will provide a rich dataset for analysis of migration patterns of CO_2 within reservoirs.

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Appendix A.

SageRider Inc. Report

Distributed Temperature Sensing (DTS) Qualitative Analysis of Injection Tests February 2017 – April 2018

Technical Memorandum

Well	Chester 16 Unit 6-16 Pilot
API	21-137-61189-00-00
Sequence	
Test Date	February 2017 – April 2018
Customer	Battelle
Data Analyst	David Brock, SageRider, Inc.
Report Date	April 20, 2018

Summary

The subject well is being used for CO2 injection for enhanced oil recovery. The well is equipped with an optical fiber Distributed Temperature Sensing (DTS) system. The well is configured to inject either to the upper three perf sets (in the A1 Carbonate geological formation) or to the lower four perf sets (in the Niagaran Brown geological formation).

In initial injection tests beginning in February 2017, the well was set up for injection into the A1 Carbonate. However, the DTS data showed signals indicative of injection into the Brown. Since that initial injection test, multiple well interventions were done to modify the wellbore configuration to better control placement of injected CO2. As such, multiple injection tests were done over the period February 2017 – April 2018.

SageRider, Inc. was engaged to perform qualitative analysis of the DTS data during the injection periods (and warmbacks between injection) and provide commentary on the injection tests, with emphasis on distribution of injection (by perf set, by geological formation).

Based on that qualitative analysis, here is a brief summary of conclusions:

1) In the initial February 2017 injection, injectate was in both the A1 Carbonate wellbore and the Brown wellbore. Injection into the reservoir appeared to be mostly into the A1 Carbonate with a small amount into the Brown.
2) Looking at the later injection beginning April 2017: injection again contacted both the A1 Carbonate and the Brown wellbores, but after the May well work, injection was contacting only the Brown wellbore. Due to the changes during the test, it is difficult to discern reservoir injection, but it does appear that most of the fluids went into the Brown.
3) Injection test 2 (injection Sep-Nov 2017) saw reservoir injection roughly equal between perf sets 1-6, with a lesser amount going to perf set 7.
4) Injection test 3 (injection Dec 2017-Jan 2018) saw reservoir injection mostly or completely to the A1 Carbonate.
5) Injection test 4 (injection Feb-Mar 2018) showed wellbore cooling in both the A1 Carbonate wellbore and the Brown wellbore, but that reservoir injection was primarily into the A1 Carbonate perf sets, with a minimal amount into the Brown perfs.

NOTE: This report is a Technical Memorandum, meant to document a summary of the current work, mainly for the benefit of those already acquainted with the project as a whole. It is not meant as a formal stand-alone Technical Report. As such, there may be only cursory introductory or background information included. For such background, the reader is directed to contact Battelle personnel involved with the project. This document documents the current work, as has already been communicated to Battelle personnel.

Introduction

The subject well is being used for CO2 injection in an enhanced oil recovery project. The well is equipped with an optical fiber cemented outside the well casing, and a Distributed Temperature Sensing (DTS) system. The well is set up to inject either to the upper three perf sets (in the A1 Carbonate geological formation) or to the lower four perf sets (in the Niagaran Brown geological formation).

In initial injection tests beginning in February 2017, the well was set up for injection into the A1 Carbonate. However, the DTS data showed cooling signals indicative of injection into the Brown, or at least out-of-target, and inconsistent with the wellbore configuration as designed. Since that initial injection test, various well interventions were done to modify the wellbore configuration to better control placement of injected CO2. As such, multiple injection tests were done over the period February 2017 – April 2018.

SageRider, Inc. was engaged to perform qualitative analysis of the DTS data during the injection periods (and warmbacks between injection) to provide commentary on the injection tests, with emphasis on distribution of injection (by perf set, by geological formation) for the various tests.

The basis of DTS analysis of injection is to infer fluid flow based on temperature changes (in time and in depth). The temperatures at a given time and depth are influenced by the existing reservoir temperature, and the temperature of the injected fluid. For gas flow, temperatures are most strongly driven by Joule-Thompson cooling: strong cooling that occurs when the flowing fluid undergoes a pressure drop. Thus, cooling signals might be seen at perfs with active injection (where injected fluid drops pressure as it leaves the perfs into the reservoir), or at places where the fluid goes through a constriction in tubing for example).

Those basic ideas are the basis for qualitative injection and warmback analysis. Temperatures during injection indicate where injection fluids move in the wellbore (although not necessarily indicating where they are entering the reservoir). Warmback analysis --- looking at how quickly locations warm back after injection has stopped --- can be a clearer indicator of reservoir zones that have had more injection: zones which have taken more injection will have had more reservoir subjected to cooling and therefore will take longer to warmback than zones that had less injection. The warmback is affected mainly by cooling of fluids as they enter the reservoir, rather than cooling due to flow within the wellbore.

Regarding Waterfall Plots

For this qualitative analysis, DTS data were plotted in the form of "waterfall plots". Waterfall plots are an excellent way to visualize DTS temperature data, particularly how temperature changes in depth and time.

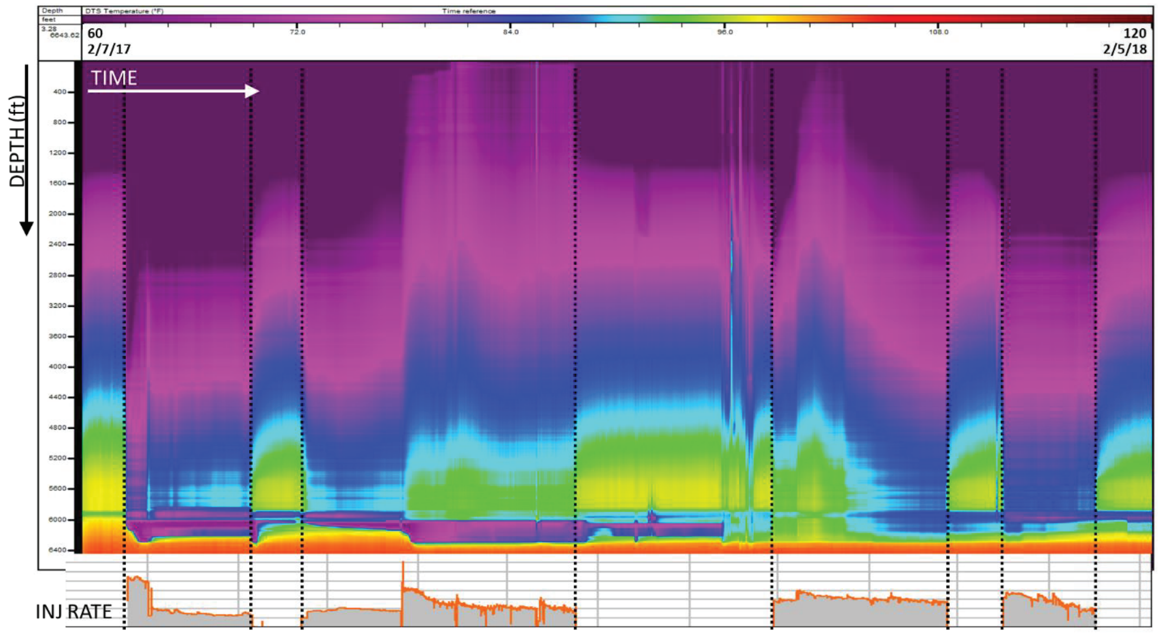

Figure 1: Waterfall Plot (full wellbore) of DTS data

The DTS temperature data for the full wellbore is shown in Figure 1. In a waterfall plot, depth is plotted downward just as in a conventional log display; time is the horizontal dimension (increasing to the right); and the temperature data (in this instance) is represented by color. The colorscale is shown at the top of this figure, going from 60° F (dark purple) to 120° F (dark red). So, in other words, the left edge of the waterfall represents the temperatures going down the entire wellbore on February 7, 2017, from surface (top of figure) to bottom of fiber/well (bottom of figure). The right edge of the waterfall plot is the February 5, 2018 timestep of temperature data gathered. Similarly, any horizontal slice across the waterfall plot shows the temperature at that depth as it changes over the time of the test. For reference, at the bottom of the figure, the injection rate is plotted.

For the first few days, there is no injection. The well is basically at its static geothermal condition: the temperature increases fairly smoothly and consistently with depth (colors change smoothly and consistently with depth). When the first injection commences, the entire wellbore cools (colors in the waterfall go toward dark purple) as cold fluid is injected.

For the rest of this report, we will be using waterfall plots as just described, except that we will zoom the vertical scale to the region near the perfs, where we wish to examine temperature changes and infer fluid flow. Further, as will be described later, we will also use "differential temperature" waterfall plots, which follow the same format except that rather than plotting raw temperatures, we will plot the temperature difference: the temperature at the given depth and time minus the temperature at that depth at the initial time. The differential temperature waterfall plot is particularly useful for highlighting temperature behavior in warmback analyses.

First Injection Test (Feb-Oct 2017)

Full-Test Temperature Waterfall Analysis

The period Feb-Oct 2017 is being called the First Injection Test. It actually consisted of multiple periods: and early injection (Feb-Apr 2017) followed by a shutin, and then a later injection (Apr-Sep 2017). That latter injection period had a major change in late May where well work was done to modify the well injection configuration.

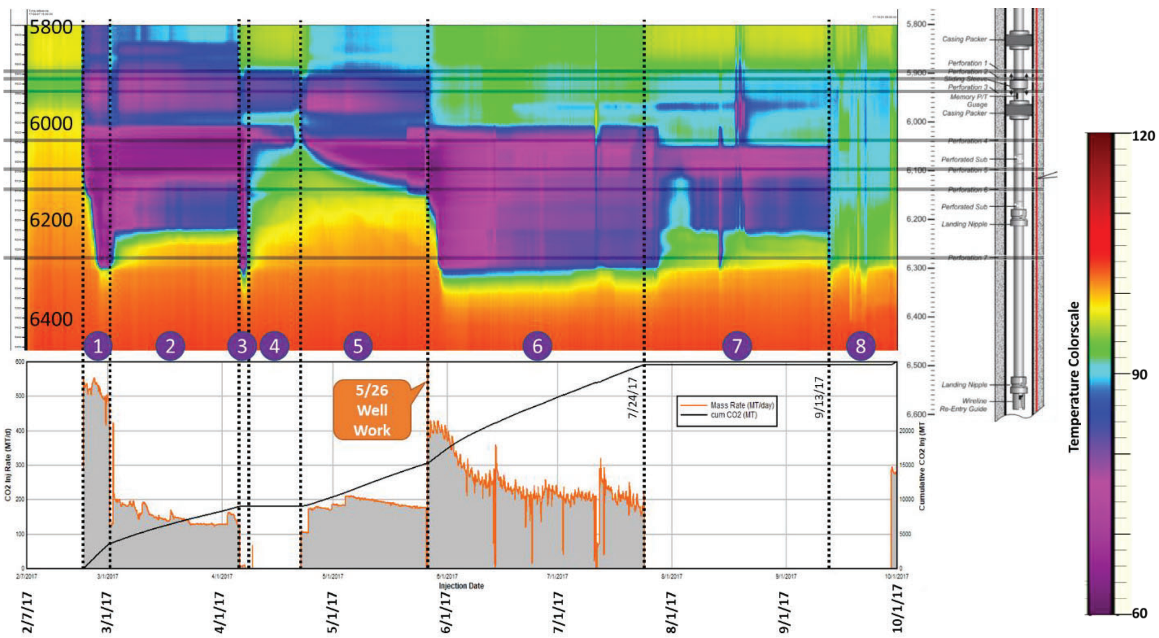

Figure 2 : Waterfall plot, depths below 5800 ft MD, 1st Injection Test

Figure 2 shows a waterfall plot, zoomed in on the deeper region of the wellbore (from 5800 ft. MD to just below 6400 feet MD; the region below that shows little temperature change). Note that a wellbore diagram is included to the right of the waterfall plot, and the depths of the perforations are highlighted by grey lines that extend across the waterfall. Farthest to the right is the colorscale. Below the waterfall plot is a plot of injection rate. So, the waterfall plot starts at left with the well at static conditions, then (as we move to the left), we move through various injection and warmback (non-injection) periods. The numbers 1 through 8 indicate various time periods of interest. Observations:

Period 1 (Initial high-rate injection) Immediate cooling of wellbore in both A1 Carbonate and Brown. Cooled depth moves downward through period 1, likely indicating displacement of a water level in the well. Cooling at the end of period 1 has proceeded to the depth of the deepest perfs (perf set 7).

Period 2 (Continuing lower-rate injection): Cooling remained within A1 Carbonate and Brown (but cooled interval retreated to a depth above perf set 7.

Period 3 (Apparent short additional injection or well work) again briefly cooled down to perf set 7.

Period 4 (Warmback): Depths corresponding to perfs 1-3 (A1 Carbonate) and 4 (Brown) appear to take longest to warmback, indicating that those perfs took the bulk of the injection with little/no injection at deeper perfs. See next section for a more detailed analysis.

Period 5 (Second injection period begins): initially cools the A1 Carbonate annulus and the upper Brown annulus, again appearing to push a fluid level down in the Brown annulus to the depth of perf set 6

Period 6 (Continued injection after May 26 well work): cool injection now appears to be going primarily into the Brown annulus (not into the A1 Carbonate annulus), pushing down as deep as perf set 7 during injection.

Period 7 (Warmback) Initial warmback appears to show that most injection went into formation through perf sets 4 and 5 (Brown), but unusual fluctuations (well work?) are likely masking important features. Thus, low certainty to these conclusions. See next section for further analysis of warmbacks.

First Injection Test Differential Warmback Analyses

As mentioned previously, the warmback often contains the most direct evidence of injection into the reservoir because there is no injection, and thus thermal effects of flowing injectate does not complicate the temperature signal. So, in warmback analysis, we are looking for (vertical) zones which take longer to warmback. Those that do take longer indicate zones which took more injection (and were therefore cooled more thoroughly).

To view warmback effects, we will use a version of the waterfall plot where instead of plotting raw temperatures, we plot a differential temperature (temperature at a given depth and time minus the temperature at that depth at the first timeslice, usually at the end of injection). This tends to accentuate the temperature differences and changes which are useful to the analysis.

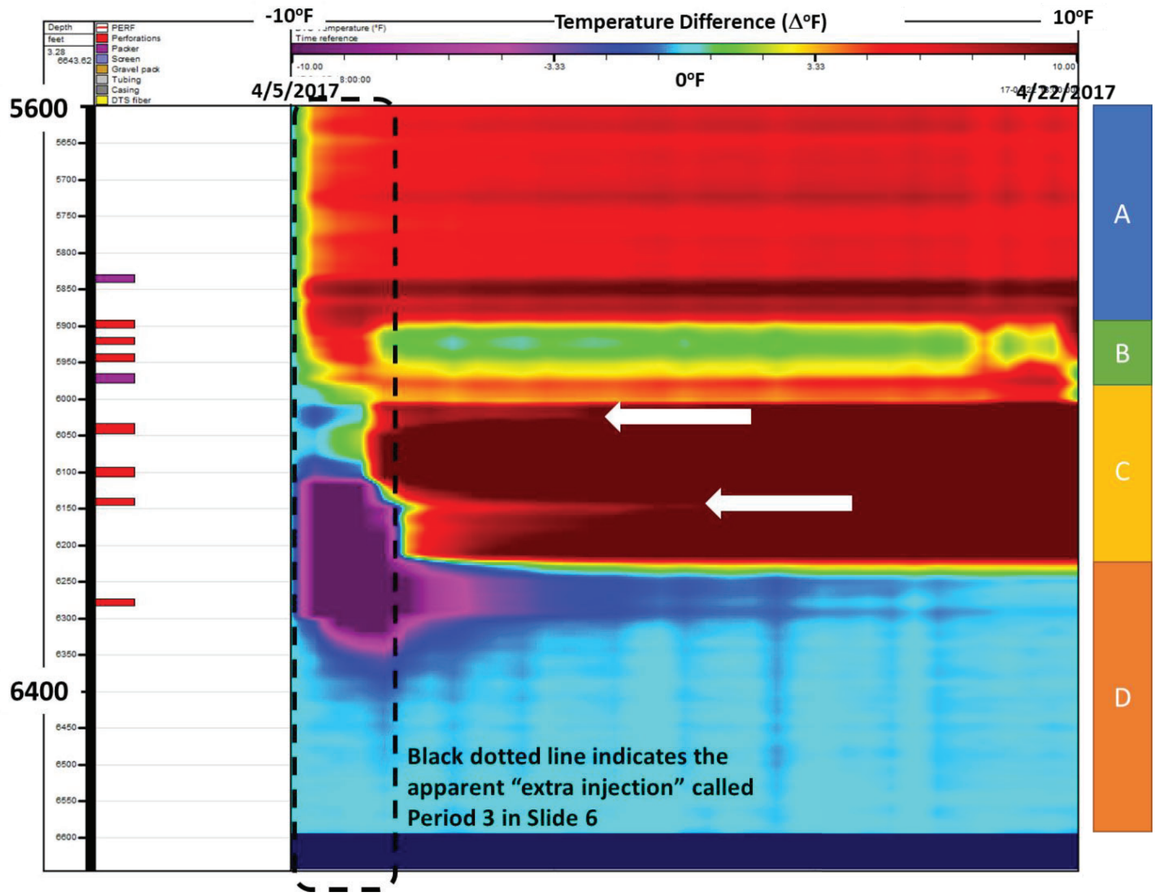

Figure 3: Differential temperature waterfall plot for the first warmback ("Periods 3 and 4") of the 1st Injection Test

Figure 3 above shows the differential temperature waterfall plot for the first warmback. Data is plotted for what was called periods 3 and 4: the brief apparent extra injection just before the first warmback. Period 3 is noted in the figure. To the left of the waterfall, the seven perf sets are noted in red. To the right of the waterfall are noted four vertical zones labelled A, B, C, and D, noting zones for the comments below:

Zone A: Fast and relatively uniform warmback indicates no fluid injection into formation as would be expected (this is the zone above perfs).

Zone B: Slow warmback indicates reservoir injection in perfs 1-3:

Zone C: In the Brown, perfs 6 and 4 show slightly slower warmback (white arrows), indicating some injection, but much less than in the A1 Carbonate.

Zone D: No warmback as this zone didn't cool appreciably during injection.

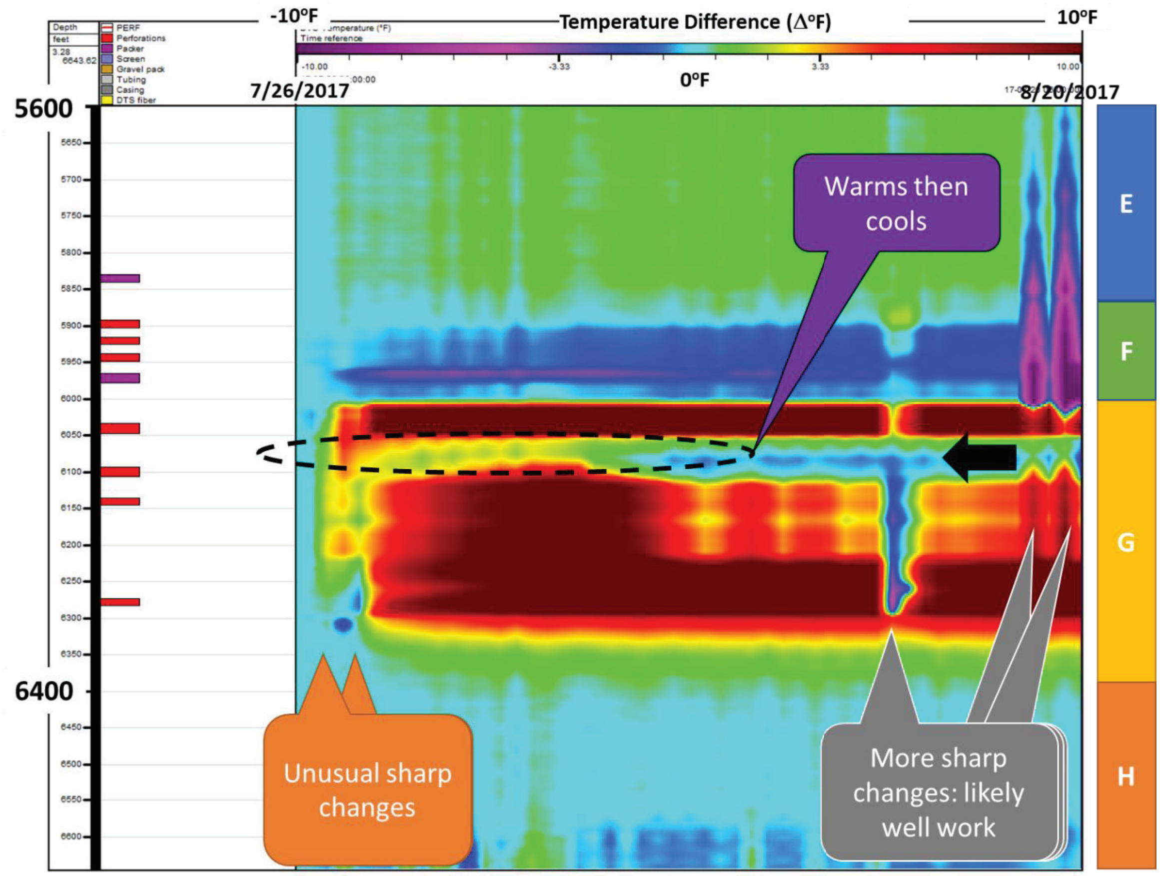

Figure 4 Differential temperature waterfall plot for the later warmback ("Period 8" of the 1st Injection Test)

Figure 4 above is the differential temperature for the second warmback of the first injection test (called "Period 7" previously). As noted earlier, there appear to be strange temperature artifacts happening during this period that could indicate well work, and these make the warmback difficult to interpret.

Zone E: Fast and relatively uniform warmback indicates no fluid injection into formation as would be expected (this is the zone above perfs).

Zone F: During injection, the A1 Carbonate annulus here did not see much cooling. Therefore, during warmback, no warming (actually slight cooling) was seen.

Zone G: During injection, cooling was here in the Brown. But in warmback, many sharp changes (noted in figure) are seen that may indicate well work or other phenomena that mask normal analysis. Apparent slow warmback is near perf set 5 (indicated), but this actually warms, then cools, thus cannot interpret confidently.

Zone H: No warmback as this zone didn't cool appreciably during injection.

Second and Third Injection Tests (Oct 2017-February 2018)

Full-Test Temperature Waterfall Analysis

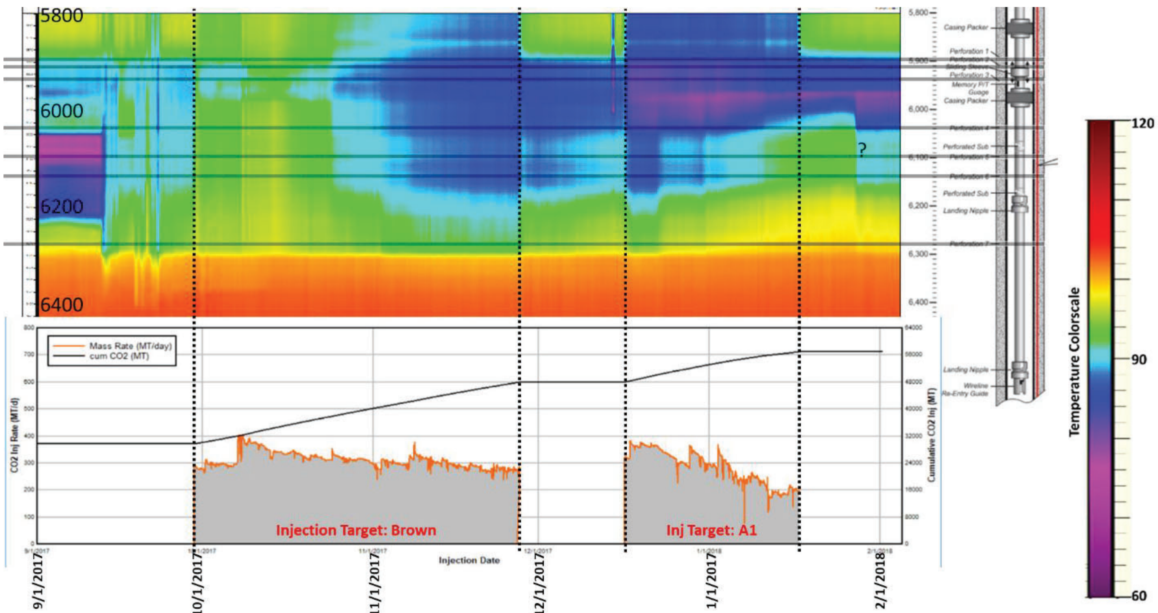

Figure 5: Waterfall plot, depths below 5800 ft MD, 2nd and 3rd Injection Tests

A waterfall plot detailing temperatures during the 2nd and 3rd injection tests is shown above in Figure 5. The 2nd test had injection Sept-Nov 2017 targeting the Brown, and the 3rd test injected Dec 2017-Jan 2018 targeting the A1 Carbonate.

Comments on the 2nd test:

There was more subtle and slow cooling during injection, likely related to different injection temperatures at surface. During injection, there was wellbore cooling in both the A1 Carbonate and Brown annuli, more pronounced in the 2nd half of injection. During warmback: slower warmback was seen from perfs 1-6 indicating possible injection at all of these perfs. Perfs 2-3 (A1 Carbonate) and perf set 4 (Brown) appear to show the slowest warmback implying these took the most injection. See section later for additional warmback analysis.

Comments on the 3rd test:

During injection, wellbore cooling almost solely in the A1 Carbonate annulus. Some lesser cooling in the Brown annulus occurs and appears to reduce and cease during the first half of the injection period. Warmback showed persistent cooling at perfs 1-3, implying those took the injection, and that there was negligible injection into the Brown. See the next section for additional warmback analysis.

Second and Third Injection Test Differential Warmback Analyses

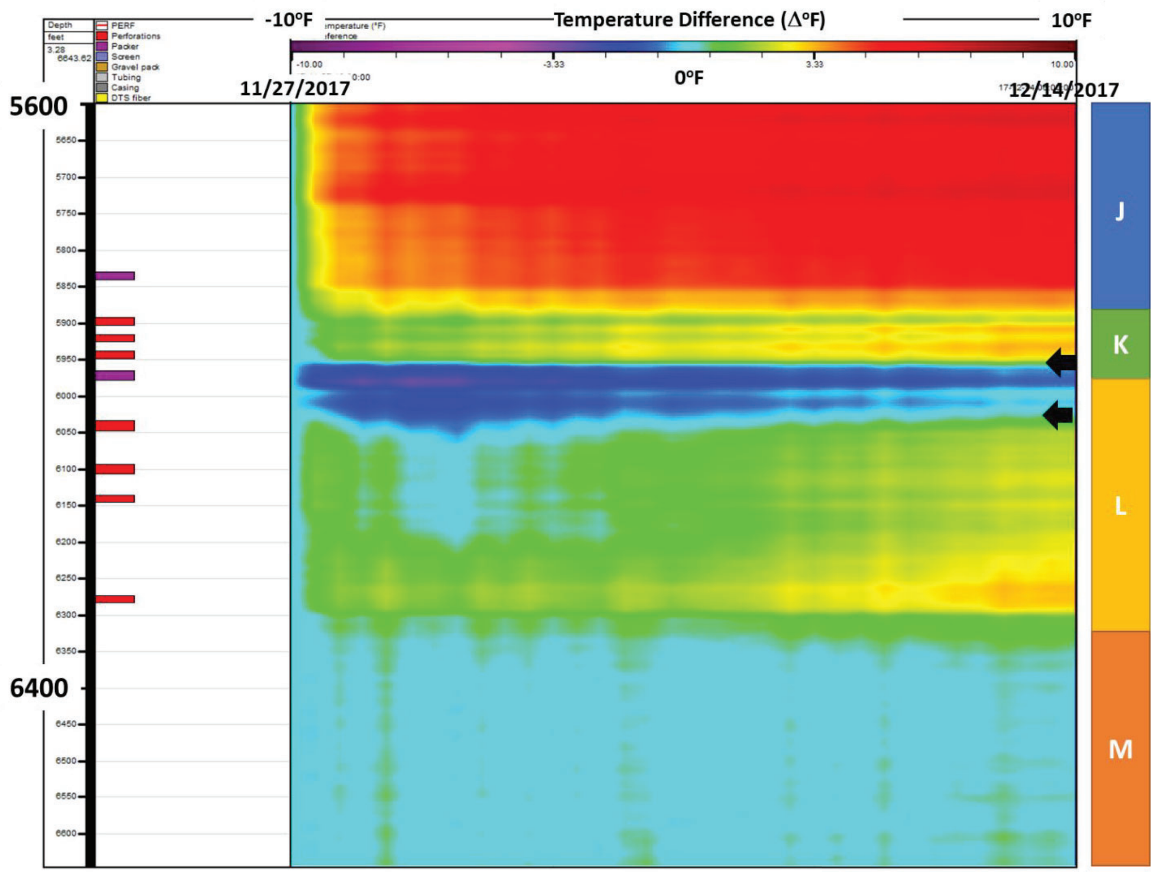

Figure 6: Differential temperature waterfall plot for the warmback of the 2nd Injection Test

The differential temperature waterfall plot for the warmback of the 2nd injection test is shown in Figure 6. Comments:

Zone J: Fast and relatively uniform warmback indicates no fluid injection into formation as would be expected (this is the zone above perfs).

Zone K: Slow warmback indicates injection in perfs 1-3: Most in 3, then 1, then 2.

Zone L: In the Brown, slowest warmback at perf 4 (slower than the A1 Carbonate perfs). Slow warmbacks at perfs 5, 6, and 7 indicate appreciable injection at these as well (~similar to the A1 Carbonate perfs). Perf set 7 took the least injection.

Zone M: No warmback as this zone didn't cool appreciably during injection.

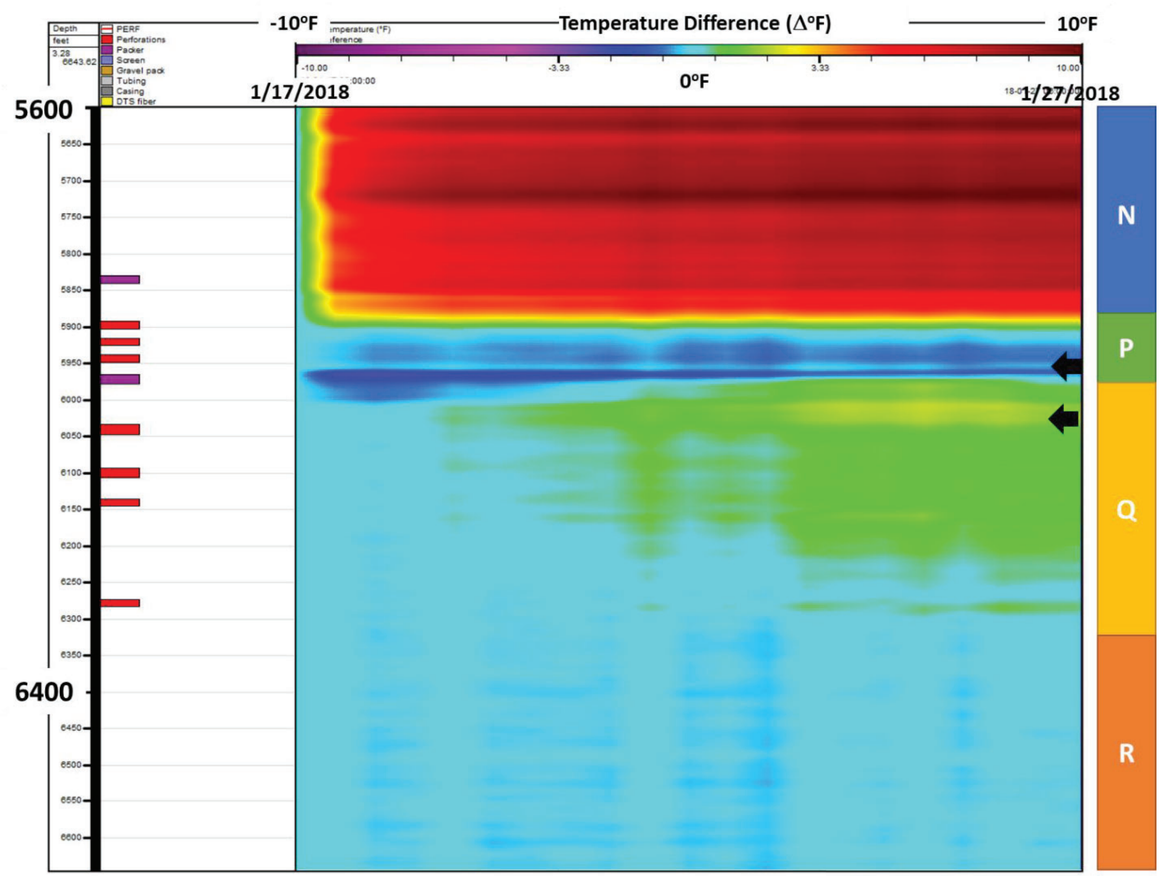

Figure 7: Differential temperature waterfall plot for the warmback of the 3rd Injection Test

Figure 7 above shows the differential temperature waterfall for the 3rd injection test warmback period. Commentary:

Zone N: Fast and relatively uniform warmback indicates no fluid injection into formation as would be expected (this is the zone above perfs).

Zone P: Slow warmback indicates injection in perfs 1-3: As before, most in 3, then 1, then 2.

Zone Q: While warmback appears slow in this region (Brown), note that there was cooling of the Brown early in injection which warmed back during the rest of injection (and here). The apparent warming back here doesn't indicate appreciable reservoir injection

Zone R: No warmback as this zone didn't cool appreciably during injection.

Fourth Injection Test (Feb-Apr 2018)

Full-Test Temperature Waterfall Analysis

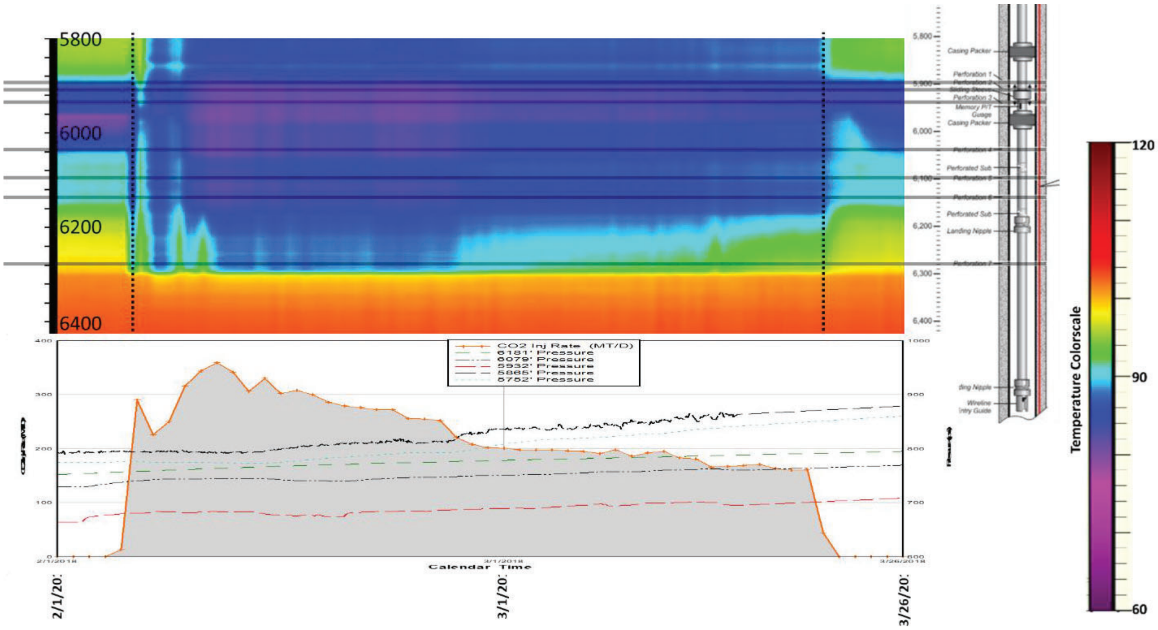

Figure 8: Waterfall plot, depths below 5800 ft MD, 4th Injection Test

A waterfall plot of the full 4th injection test is shown above in Figure 8. The following were noted during analysis:

During injection, the character of the waterfall plot is similar to the third injection test (Dec '17-Jan '18) targeting the A1 Carbonate.

During injection, strongest cooling was seen in the vicinity of perfs 1-3 (A1 Carbonate). There was cooling also in vicinity of perfs 4-6 (Brown) and to a lesser and sporadic extent, to perf 7. However, over the injection, that initial cooling in the Brown starts to warm, which could indicate some of the injectate in the wellbore but not necessarily going into formation in appreciable amounts.

Once injection ceased, the Brown perfs warmed back more quickly than the A1 Carbonate perfs, indicating that the A1 Carbonate took the bulk of the injection. Some injection may have entered the Brown at a lesser amount than the A1 Carbonate. More details on warmback will be in the next subsection using the differential temperature warmback analysis.

Offset pressures gave some additional inferences:

- Upper two offset pressure gauges (A1/A2) start off with higher pressures than the Brown gauges indicating that the A1 Carbonate had already been pressured up relative to the Brown.
- At the beginning of the injection, those upper two gauges are fairly flat, but then start rising more around 2/25 when the injection rate reduced somewhat. Was there an operational change there?
- Brown offset gauges show rises during the injection, again consistent with some of the injection going into the Brown, again likely in lower rates than into the A1 Carbonate.

Fourth Injection Test Differential Warmback Analysis

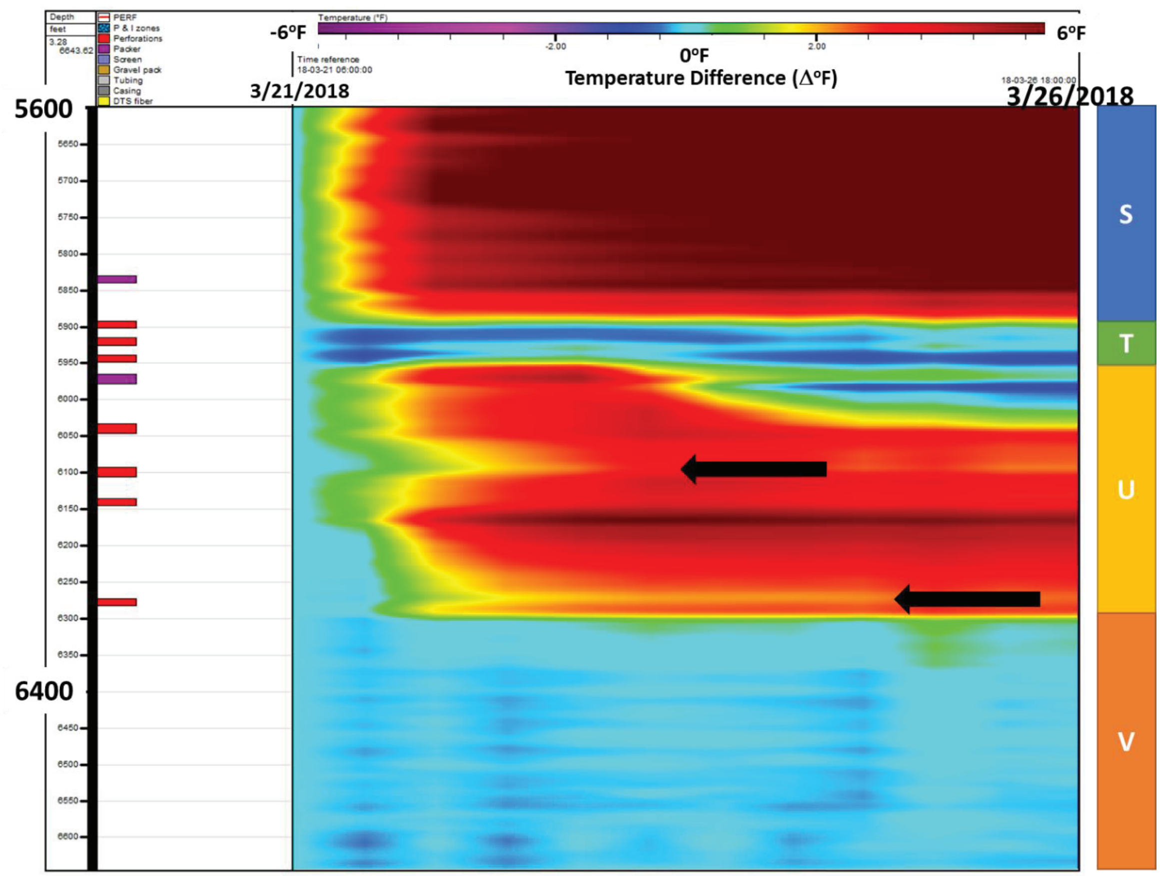

Figure 9: Differential temperature waterfall plot for the warmback of the 4th Injection Test

The differential temperature warmback analysis waterfall plot is shown in Figure 9. Note that approximately midway through the time period shown in the plot there is a strange "deepening" of the cooled zone, possibly due to fluid movement in the wellbore? Commentary on the warmback by zone:

Zone S: Fast and relatively uniform warmback indicates no fluid injection into formation as would be expected (this is the zone above perfs).

Zone T: Very slow warmback indicating that the main injection took place here (perfs 1-3, A1 Carbonate)

Zone U: Faster warmback indicates much less injection than in A1 Carbonate. Of these, slower warmback as indicated (black arrows), corresponding to perfs 5 and 7. These are fairly subtle, so are not high confidence.

Zone V: No warmback as this zone didn't cool appreciably during injection.

Conclusions

Test 1 (Early injection Feb-Apr 2017 and warmback): During injection, cold injectate was seen in both the A1 Carbonate and Brown depths of the wellbore, sporadically making it as deep as the deepest perf set (perf set 7). Warmback analysis showed that much of the injection was into perf sets 1-3 (A1 Carbonate) with small amounts into perf sets 4 and 6 (Brown).

Test 1 (Later injection Apr-July 2017): Prior to the well work in late May, injection again cooled the A1 Carbonate zones and the Brown (this time deepening slowly in the Brown, making it as deep as perf set 6 by the May well work). After the May well work, cooling indicated that injection now was restricted to the Brown wellbore (initially perf sets 4-6 which fairly quickly deepened to the depth of perf set 7). Many artifacts made interpreting the warmback difficult. It appears clear that injection was primarily into the Brown.

Test 2 (injection Sep-Nov 2017): During injection, strongest cooling in the wellbore perf sets 1-4 with slightly lesser cooling to perf sets 5-6. Warmback confirmed that reservoir injection occurred fairly equally distributed between perf sets 1-6, with a smaller amount of injection in perf set 7).

Test 3 (injection Dec 2017- Jan 2018): During injection, cold injectate appears isolated to the A1 Carbonate wellbore, with a lesser amount initially appearing in the Brown wellbore but reducing and then ceasing. Warmback analysis confirms that most or all of the reservoir injection was in the A1 Carbonate, roughly ranked from perf set 3 (higher), then perf set 1, then perf set 2.

Test 4 (injection Feb-Mar 2018): During injection, injectate cooling seen in both the A1 Carbonate and the Brown sections (perf sets 1-6 with sporadic light cooling to perf set 7). Warmback analysis shows primary injection into the A1 Carbonate perf sets, with a small amount into the Brown (possibly mostly into perf sets 5 and 7, but cannot say with much confidence).

It can be done