**WELLBORE CORROSION AND FAILURE ASSESSMENT FOR CO₂ EOR AND
STORAGE: TWO CASE STUDIES IN THE WEYBURN FIELD**

Prepared by:

Jason D. Laumb

Energy & Environmental Research Center

University of North Dakota

15 North 23rd Street, Stop 9018

Grand Forks, ND 58202-9018

Phone: (701) 777-5114; Fax: (701) 777-5181; E-Mail: jlaumb@undeerc.org

WELLBORE CORROSION AND FAILURE ASSESSMENT FOR CO₂ EOR AND STORAGE: TWO CASE STUDIES IN THE WEYBURN FIELD

Jason D. Laumb,^{a,*} Kyle A. Glazewski,^a John A. Hamling,^a
Alexander Azenkeng,^a and Theresa L. Watson^b

^a Energy & Environmental Research Center; University of North Dakota, 15 North 23rd Street,
Stop 9018, Grand Forks, ND 58202-9018, United States

^b T.L. Watson & Associates, No. 1, 1922 9th Avenue Southeast, Calgary, AB, T2G 0V2, Canada

* Corresponding Author: Tel.: +1-701-777-5114, Fax: +1-701-777-5181

E-Mail Addresses: jlaumb@undeerc.org (J.D. Laumb), kglazewski@undeerc.org (K.A. Glazewski), jhamling@undeerc.org (J.A. Hamling), aazenkeng@undeerc.org (A. Azenkeng),
theresa.watson@tlwatson.com (T.L. Watson)

ABSTRACT

Many depleted oil and gas reservoirs are targets for CO₂ enhanced oil recovery, resulting in CO₂ storage as part of the commercial enhanced oil recovery process. These oil fields have legacy wellbores that may contain a leakage pathway. Corrosion or degradation can occur anywhere along the wellbore through or along the cement, casing, tubing, or plugs and is a challenging issue facing the oil and gas industry. Two case studies presented here evaluate legacy wells in the Weyburn oil field. One well has injected over 263 million cubic meters of CO₂, and the second well has not been exposed to CO₂. These case studies aim to help understand casing corrosion in CO₂-rich environments.

Both wellbores exhibited signs of corrosion, with corrosion ranging from small pits to complete penetration through the casing. Contributing factors to corrosion in these wells range from exposure to injected fluids, injected CO₂, packer placements, formation fluid exposure, and the corrosive environment that is present in the perforated area of the well.

KEYWORDS

Corrosion, CO₂, EOR, Wellbore Integrity

1.0 INTRODUCTION

The process of carbon capture and storage (CCS) in geologic media has been identified as an important means for reducing anthropogenic greenhouse gas emissions into the atmosphere (Bradshaw and others, 2007). Several different types of geologic media are available for the storage of carbon dioxide (CO₂), including depleted oil and gas reservoirs, deep brine-saturated formations, CO₂ enhanced oil recovery (EOR) operations, and enhanced coalbed methane (ECBM) recovery. The storage of anthropogenic CO₂ in geologic media is a technique that is immediately applicable as a result of the experience gained through oil and gas exploration and production and deep waste disposal. Studies have shown that geologic media have a great potential for CO₂ storage, with retention times of centuries to millions of years (Intergovernmental Panel on Climate Change [IPCC], 2005). Geologic storage of CO₂ is being actively investigated and pursued at multiple locations across the United States, Canada, and the world.

Three geologic media have been identified as primary targets for CO₂ storage: unminable coal seams, depleted oil and gas reservoirs, and deep (>800 meters) saline formations (also referred to as deep saline aquifers). Storage of CO₂ in coal seams has the smallest potential in terms of storage resource and is an immature technique that has not yet been proven commercially viable (Bachu and others, 2012). Depleted hydrocarbon reservoirs have demonstrated storage and confinement properties by having previously stored oil and/or gas resources for millions of years. The quest to discover and extract hydrocarbon resources has provided a broad base of understanding about the subsurface in oil- and gas-producing areas. A potential challenge associated with the use of depleted oil and gas reservoirs for CO₂ storage is the numerous wells drilled in these areas which may impact storage security (Bachu and others, 2012). Deep saline formations are more widespread and, theoretically, have correspondingly larger storage capacities. Deep saline formations may have fewer wellbore penetrations in areas without oil and gas exploration and production activities, which may improve storage security. Wellbore integrity in oil fields (Brondel and others, 1994) and CO₂ storage environments (Celia and others, 2004; Choi and others, 2013) has been studied in past work. While the studies in CO₂ storage environments are more recent, the corrosion mechanisms and leakage pathways are still very similar.

The Weyburn–Midale CO₂ EOR project has been in operation since 2000. During this time, the Petroleum Technology Research Centre (PTRC) has led an impressive research program that has utilized the Weyburn–Midale Field as a field laboratory for many projects on EOR and CO₂ storage, ranging from monitoring, verification, and accounting (MVA); modeling; and wellbore integrity to risk management and public outreach (Hitchon, 2012). Hawkes et al. (2011) have reviewed the literature extensively in an effort to better understand the impact of wellbore integrity on the long-term security of CO₂ storage reservoirs, with the primary focus on topics such as i) wellbore annular seal, ii) cement degradation in CO₂, iii) steel corrosion in CO₂, and iv) operational issues associated with CO₂, as well as other issues linked to CO₂ EOR and/or storage. The major conclusion from their review identified cement integrity as the most important indicator of wellbore integrity. Although the integrity of the cement is important, the roles played by casing, wellbore completion practices, and history of well operational activities are also important, especially for legacy wells that are being converted from oil producers to water and/or CO₂ injection.

This paper is based on research conducted with the goal of investigating wellbore casing corrosion and failure assessment for CO₂ EOR and storage through evaluation of wellbore casing and cement, estimation of in situ corrosion rates, and identification of the locations within the wellbore for corrosion occurrences for selected case studies in the Weyburn oil field. The two case study wells presented here are a selected sample of the evaluated wells for the larger project (Sacuta and others, 2016). The primary challenge in evaluating wellbores in the Weyburn field was a lack of available log data. Casing and cement evaluation logs are typically only run when there is an indication of an issue within a wellbore. Even in those cases where there is a potential problem, the log is usually run over the well depths of interest. As such, identifying enough wells to evaluate was a significant challenge, even though the entire oil field had over 3100 wells as potential candidates. The authors and project sponsors recognized this challenge, and it can be speculated that this may be an indication of the overall good condition of wellbores in the study area. There was a relative lack of well evaluation logs, and this may be indicative of generally good wellbore integrity within the field.

2.0 MATERIALS AND METHODS

Information regarding wells in the Weyburn Field was collected from public and nonpublic data in Saskatchewan and maintained in a database. With over 3100 wells in the Weyburn Field, the first task was to select wells with enough data to provide a meaningful evaluation. Location and availability of casing and cement evaluation logs were the primary drivers in selecting the case study wells. The preferred locations were for wells to be in proximity to where CO₂ had been injected, thus exposed to CO₂, and wells to be just outside of the primary CO₂ injection area in order to maintain a relatively consistent geology.

A broad variety of commercial downhole geophysical technologies currently exists and is commonly employed in the oil and gas industry, that can be, and is being, adapted for application in the emerging field of geologic storage of anthropogenic CO₂. These technologies are useful for developing data that are critical for site characterization activities, for MVA of injected CO₂, and for determining the viability of existing wellbores (Hamling and others, 2011). Logs that were sought included a combination of caliper logs, ultrasonic bond logs, sector bond logs, vertilog, and casing imaging logs.

The ideal case study wells were envisioned to have had an array of logs that had been run over the well's history, including pre- and post-CO₂ injection, to evaluate how the cement and casing had changed over time. About ten wells were identified as candidate case study wells, with the study's authors and project sponsors settling on the evaluation of five case study wells. This paper presents the detailed results from two of those wells, while acknowledging some of the results learned from the collective evaluation of the five case study wells.

While selecting wells with the most robust casing and cement evaluation logs was necessary, often wells are logged to evaluate a known issue. Therefore, while the results may generally be representative of corrosion mechanisms present, the corrosion can be from a variety of factors, and the results do not indicate that a specific mechanism is more or less likely to occur at a substantially higher frequency.

Internal and/or external casing corrosion were deemed critical objectives and were evaluated by a combination of caliper logs and casing imaging logs where available. The quality of the cement was evaluated by CBLs (cement bond logs), sector bond logs, or ultrasonic bond logs. Some of the logs that were available covered the entire length of the wellbore, but in other cases, only targeted intervals of the well were logged. The case study wells were selected based on the log suites available within the study area and, therefore, may not represent as comprehensive of a data set as ideally desired. Ideal case studies are difficult to obtain because well-logging activities do not have scholarly research as a main objective. The reader must keep in mind that the case studies chosen were based on historical well log data. The two cases presented in this paper are referred to as Case 1 and Case 5. The case references are such that the reader may read the complete study in a comprehensive form, without renumbering the case studies (Sacuta and others, 2016).

3.0 WELL HISTORY

3.1 Case Study One

This well is a vertical water/CO₂ injector that was drilled in 1957 in the area that eventually became Phase 1a of the Weyburn CO₂ injection program. Production records indicate the well was in production from 1957 to 1964. Water injection in this well started in 1964, and it was converted to a water alternating gas (WAG) injector in 2000 as part of the Weyburn EOR project. This well was a WAG injector until late 2008, after which it injected only water until its abandonment in November 2010. Perforations created for production and/or injection purposes are in the interval from 1391.1 to 1400.3 mKB (meters below kelly bushing) and 1402.4 to 1403.9 mKB in the Marly and Vuggy Formations within the Midale Beds. An abandonment program was initiated in 2009 and completed in 2010 because the wellbore casing integrity was deemed unsuitable for WAG injection. As part of the abandonment process, a cement squeeze was performed in 2010 to plug off the production perforations.

The casing record presented in Table 1 indicates that Steel Grade J-55 was used for the surface and production casing strings. Cement records indicate that the surface casing was cemented with 180 sacks of Saskatchewan construction cement with 2% CaCl₂. The production casing was cemented with 180 sacks of Dowell bulk cement with 3% gel to 365 m above the shoe. Well data sheets also indicate that 25.5 tonnes of Class G cement with CaCl₂ additive was used for the cement squeeze program in 2010.

Table 1. Casing Record and Characteristics for Case Study 1

String	Weight, kg/m	Grade	OD, ¹ mm	ID, ² mm	Depth m
Surface	35.72	J-55	219.1	205.7	90.74
Production	20.83	J-55	139.7	127.7	1420.37

¹ Outer diameter.

² Inner diameter.

This well was selected as a case study for two key reasons: 1) activity in the well spans the period before CO₂ injection (1957–2000), active CO₂ injection (2000–2009), and post-CO₂ injection (2009–present) and 2) logs are available in each of the three periods, although the log types vary as well as the interval that was logged. Such information provides a means of assessing casing and cement integrity pre-, during, and post-CO₂ injection for this well.

3.2 Case Study Five

The Case Study 5 well was drilled in 1962 as a vertical oil production well, with existing perforations in the interval from 1470.1 to 1471 mKB in the Midale Bed. Production records indicate that oil production in this well was from 1962 to 1995, with production activities suspended on January 31, 1995. The well data files do not indicate the reason for the suspension, but a cement retainer was placed at 1459.24 m, and the annulus was inhibited. Records indicate this well is still suspended as of July 2014, the last month of records available for this study. Based on casing integrity surveys conducted in 2011, it is possible the suspension had to do with deteriorating casing integrity evidenced by the multiple penetrations observed on a CIT (casing imaging tool) log run in 2011 (see corrosion evaluation section below).

The casing record presented in Table 2 indicates that steel grade J-55 was used for the surface and production casing string. The well's TOC (top of cement) is at 1142 m.

Table 2. Casing Record for Well Case Study 5

String	Weight, kg/m	Grade	OD, mm	ID, mm	Depth, m
Surface	35.72	J-55	219.1	205.7	127.9
Production	14.14	J-55	114.3	103.9	1488.9

This well was selected as a case study, in part, because of its location outside of the main CO₂ injection area and because it is a vertical well beginning as an oil producer, similar to the other case in the study. Although it was completed in 1962, it was expected that the completion practices were largely similar to those of the other case study well to allow for a comparative analysis of the corrosion status. Furthermore, this well was only used as a production well; thus it has not had direct contact with injected fluids or the placement of packers.

3.3 Case Study History Comparison

The two case study wells presented show that each had integrity/corrosion issues that affected the operation of each well. Each well's history was investigated and is shown in Table 3. The well history was constructed based upon available data, including completion reports, sundry notes, and any other documentation available at the time of the study. The well history provides insight into the observations found when the available logs were evaluated for each well.

Table 3. Well History of Case Study Wells

Activity	Case Study 1 Date	Case Study 1 Notes	Case Study 5 Date	Case Study 5 Notes
Spud Well	June 1957	–	Dec. 1962	–
Oil Production	1957–1964	7 years	1962–1995	33 years
Water Injection	1964–2000	>741 million m ³ of water	–	–
WAG Injection	2000–2008	>263 million m ³ of CO ₂	–	–
Current Status	Nov. 2010	Abandoned	Jan. 1995	Suspended with cement retainer
Well Stimulation	Aug. 1987	1391–1403 m, 28% HCl. Had to re-perf and reacidize two days later.	–	–
Vertilog/Micro Vertilog	Aug. 1987 and Sept. 2002	–	–	–
Cement Bond Log	Aug. 1987 and Sept. 2002	–	–	–
Sector Bond Log	Sept. 2014	–	Oct. 2011	–
Caliper Log	Sept. 2008	–	Oct. 2011	–
Casing Imaging Tool Log	–	–	Oct. 2011	–
Ultrasonic Radial Scanner Log	–	–	Oct. 2011	Data not reliable due to problems during logging
Packer Set	May 2000	Set packer at 1360 m	–	–
Packer Pulled	Oct. 2010	–	–	–
Suspended	–	–	Jan. 1995	Suspended with cement retainer
Abandonment	Nov. 2010	Cement squeezed perforations	–	–
Other	June and Aug. 2006	Ran two sets of 40 L Corgard ^a 70 down annulus	May 1992	Tubing leak, changed out PSN ^b and ran new TK-99 ^c joint.

^a Corrosion inhibitor.^b Pump-seating nipple.^c Internal tubing coating for corrosion protection.

4.0 RESULTS FOR CASE STUDY 1

An evaluation of corrosion for any production or injection well involves an assessment of at least the casing and cement integrity. For the subject well, Vertilog™ and acoustic CBLs are available from 1987; a casing inspection, Vertilog, and another CBL from 2002; an X–Y MIT (multifinger imaging tool) survey in 2008; and an SBT (sector bond tool) logged in 2014. Although the intervals logged vary for different log types, these logs do provide an overview of the casing integrity for this well that covers the three periods of activities indicated above. Results from the examination of these logs are presented below for the casing integrity status and the cement integrity status. The results are presented in chronological order. Table 4 below contains the logs available for this well as well as the interval logged.

Table 4. Well Log Analysis – Case Study 1

Log Type	Log Date	Application	CO ₂ Injection	Log Top Interval, m	Log Bottom Interval, m
Vertilog	8/24/1987	Internal/external corrosion	Pre-	Surface	1408
Acoustic CBL	8/24/1987	Cement integrity	Pre-	1283	1409
Micro Vertilog™	9/25/2002	Internal/external corrosion	During	Surface	1353
CBL	9/25/2002	Cement integrity	During	1100	1351
X–Y Caliper	9/19/2008	Internal corrosion	Post-	1336	1376
SBT	9/21/2014	Cement integrity	Post-	Surface	1258

4.1 Status 1987

4.1.1 Vertilog

Corrosion was evident in the bottom of the casing from about 1375 to 1408 m, with multiple penetrations (nonproduction) observed. Two of the three penetrations were in the immediate zone above the existing production perforations at 1372.5–1383.5 m and 1383.5–1389.5 m. The third penetration at 1389.5–1402 m is likely an existing production perforation in this well. The lower two-thirds of the production casing from about 360 to 1375 m was in good condition at the time this log was run in 1987, while the upper third from 360 m to the surface casing shoe at 90 m displayed multiple single isolated pitting (SIP) instances of Class 2 type. The interval above 90 m showed only two Class 2 SIP defects at about 54.6 and 90.5 m. Generally, the uppermost casing interval was in good condition in 1987. The scheme used to classify the defects and the corresponding code symbols used in each case are presented in Table 5, and a schematic representation of defects by classification is provided in Figure 1.

Table 5. Corrosion Evaluation Classification Scheme

Code Symbol	Classification
U	Unclassified (< 20% wall loss)
2	21% to 40% wall loss
3	41% to 60% wall loss
4	61% to 80% wall loss
P	Penetration

4.1.2 Acoustic Cement Bond Log

An acoustic CBL was surveyed in 1987 over the interval from 1283.4 to 1409.1 m. The log results show excellent bonding to both pipe and formation over this interval. The VDL (variable-density log) shows strong formation arrivals and low-amplitude early arrivals, which are consistent with good bonding conditions. No cement map was available, and it is not possible to deduce the presence of channeling or microvoids from this log. Figure 2 contains the results of this log.

4.2 Status 2002

4.2.1 Micro Vertilog

The Micro Vertilog surveyed in 2002 evaluated the interval from surface to 1353 m, with the bottom log interval about 55 m above the bottom log interval from the 1987 log (surface – 1408 m). Also, the 2002 interval does not include the zone with existing production perforations at 1372.5–1383.5 m and 1383.5–1389.5 m. The results indicate that the production casing string had suffered increased corrosion since the 1987 survey. The top 100 m of casing was in very good condition in 1987 but had a Class 3 pit with 60% wall loss at 44.28 m. Additionally, 24 Class 3 pits were identified below 100 m in depth, of which 13 were located between 100 and 335 m. Also noted from the results is the fact that all of the Class 3 pits from 100 to 335 m are on the external casing surface, while most from 335 m and lower are on the internal surface, quite possibly due to additional isolation from geologic formations provided by the surface casing. A detailed list of the corrosion defects with more than 20% wall loss is schematically represented in Figure 1; the pits are classified by color and location (internal vs. external) on the schematic diagram. Note that this well log may show more external corrosion because of the specific tool that was used. The Micro Vertilog is a magnetic flux tool that evaluates both internal and external surfaces of the casing directly, while other tools use methods of internal measurement and wall thickness to calculate external surface corrosion. Additional information about the log types can be found in the full report (Sacuta, 2016).

The 2002 log did not survey the bottom 55 m of the casing relative to the 1987 log and, therefore, did not include the zone with the three production perforations identified in the 1987 log. The 2002 log shows multiple Class 3 pits emerging on the production casing string. Given that most of these defects are on the external surface of the casing, evidence suggests cement quality will play a critical role in ensuring isolation between formation fluids and overlying zones via the wellbore should casing corrosion continue to intensify and not be remediated. Figure 2 shows a summary of the number of corrosion-affected joints by their classification for

Figure 1. Schematic representation of 1987 Vertilog CBL and 2002 Micro Vertilog CBL results.

Figure 2. Summary of number of defective joints by classification, obtained in 1987 and 2002 for Case Study 1.

the 1987 Vertilog and 2002 Micro Vertilog. It should be noted that the resolution of the Vertilog is not as high as that of the Micro Vertilog and the Vertilog also did not have the accompanying quantitative wall loss summaries and position of defects from the caliper arms as was the case in the 2002 Micro Vertilog. However, detailed inspection of the logs indicated that there was the presence of corrosion in some joints where the Vertilog simply reported one instance per joint. As shown in Figures 1 and 2, the amount of casing corrosion had increased, both in severity and in joints affected, throughout the wellbore from 1987 to 2002.

4.2.2 Cement Bond Log

In 2002, a pressurized CBL survey at 7 MPa was conducted to check the cement integrity. The interval logged was from 1100 to 1351 m with the TOC being 1133 m. Based on the log results of the pressurized pass, there is poor cement bond to the casing pipe between 1133 and 1175 m, and there appears to be a weak bond to the formation. The VDL shows high-amplitude early arrivals and weak formation arrivals. However, the interval from 1175 to 1351 m has excellent bonding to both pipe and formation. The VDL shows strong formation arrivals and low-amplitude early arrivals, indicating good bond to pipe and formation.

A high-speed overview pass (no pressure) was also run from the surface to 1349.97 m. The log results show the top of the fluid at about 180 m (sonic logs require fluid-filled boreholes). The last section from 1175 to 1350 m shows excellent bonding to both pipe and formation. The VDL indicates both strong formation arrivals and low-amplitude early arrivals, which indicates good bond to pipe and formation. Figure 1 contains a schematic representation of the 2002 CBL.

4.3 Status 2008

4.3.1 Multifinger X–Y Caliper

An X–Y caliper tool was logged in 2008 over the interval from 1336.65 to 1376.24 m. Based on observations from the log, corrosion was found in the interval from 1362 to 1368 m, with at least 70%–80% casing wall loss. It was also found from the log that the casing section from 1368 m was not present, as shown in Figure 3. The well files do not indicate that the casing was intentionally removed; rather they suggest corrosion is the reason for the missing casing, possibly because of multiple packer settings in this area as well as exposure to fluids below the packer, including CO₂. A schematic representation of the MIT results is found in Figure 4.

Figure 3. X–Y caliper log shows missing casing section in Case Study 1.

4.4 Status 2014 – Sector Bond Tool

An SBT was logged to evaluate the quality of the cement behind the casing in 2014. During this survey, the log was conducted without any pressure applied to the casing because the connection between the wellhead and the flange did not hold pressure. Based on available well information, there is no indication of the presence or absence of fluids in the wellbore during the SBT logging survey. The cement top was identified in this log as ~1147 m, previously near 1133 m. It is not expected that cement from 1133 to 1147 m has deteriorated; rather, this can be explained by tool sensitivities or anomalies in the cement job not detected by previous tools.

Figure 4. Schematic representation of 2008 MIT and 2014 SBT log.

Observations from the log show excellent cement bond from 1145 to 1256 m, with the 3-ft amplitude ranging from 0 to 5 and 0 to 12 mV, respectively. The VDL in the interval shows strong formation arrivals and low-amplitude early arrivals, indicative of good bond to both casing and formation. However, the cement map shows a few microvoids between 1165 to 1178 m and at about 1253 m. Extended zonal isolation is expected in the 1145 to 1256 m interval with generally good cement bond to the casing and formation. A schematic representation of the results is found in Figure 4.

4.5 Case Study 1 Results Summary

Casing evaluation in 1987 showed two penetrations in the lower wellbore at (1372.5–1383.5 m and 1383.5–1389.5 m), which is the zone just above the existing production perforation interval. However, the casing was generally in good condition in 1987. In 2002, the Micro Vertilog results indicate increased corrosion tendencies, with one Class 3 pit found in the upper interval and several in the lower interval. These pits exist on both the internal and external surfaces of the casing.

A 2002 CBL shows good cement from 1175 to 1351 m, with good bond to both formation and casing. A 2014 SBT log indicates good cement in the interval from 1145 to 1256 m; the bond to pipe is good, but the bond to formation is weak. Overall, the log indicates extended zonal isolation is possible in the lower wellbore based on current cement evaluation.

The amount and severity of internal corrosion slightly increase from top to bottom of the wellbore, while external severity decreases from top to bottom. This is consistent with good external cement protection at the bottom of the wellbore and less in the section of free pipe from below the surface casing cement and above the TOC for the production casing.

It should be noted that this well was scheduled for abandonment in 2010 because of corrosion issues. Several packers/seals became distorted from exposure to CO₂ and were pulled and replaced throughout the well history. Potential contributing factors for corrosion in this well include exposure to CO₂ and pulling and replacing packers.

5.0 RESULTS FOR CASE STUDY 5

An evaluation of corrosion status in this well was made based on available logs that have been used to assess the casing and cement integrity. The logs that were available include SBT, MSC, CIT, and URS; the log details are presented in Table 6. Although the logs represent a desired set of logs that can be used to evaluate both the internal and external casing surfaces as well as the cement around it, all of the logs were run in 2011; thus long-term evaluation of the corrosion status over time is made difficult. Nonetheless, the current assessment can be used as a basis for future evaluations and to compare with data from the other case study. Interpretations of the logs for this case study are presented in the following sections.

Table 6. Well Log Analysis – Case Study 5

Log Type	Log Date	Application	Top Log Interval, m	Bottom Log Interval, m
SBT	10/09/2011	Cement integrity	7.9	1452.8
MSC	10/10/2011	Internal corrosion	3.1	1454.6
CIT	10/11/2011	Internal/external corrosion	0	1454.3
URS*	10/21/2011	Cement integrity and casing evaluation	3.1	1447.2

* URS data were found not to be reliable because of problems during logging and thus were not included in evaluation of this well.

5.1 Status 2011

5.1.1 Sector Bond Tool

An SBT was logged to evaluate the cement quality. The SBT was logged with both pressurized and unpressurized passes to investigate the presence of a microannulus and/or its severity. A detailed analysis has been performed using the SBT log from the unpressurized pass to be consistent with the analysis done for other wells. Based on the SBT log, the cement top was found to be at ~1142 m.

The interval from 1142 to 1455 m has excellent bonding to both casing and formation as indicated by the strong formation arrivals and low-amplitude early arrivals in the VDL. The cement map also shows very good cement coverage around the pipe in this interval, and effective zonal isolation can be expected. However, a few microvoids and a few isolated channels are present in the cement map toward the top of this zone from 1142 to 1160 m. A schematic representation of the SBT can be found in Figure 5.

5.1.2 Multisensor Caliper

The MSC log indicates that approximately 150 joints have Class 2 pits and six are unclassified (Code U), which would suggest mainly generalized corrosion with 20%–40% casing wall loss. However, the CIT results show a much different condition that shows multiple pits and penetrations. Figure 6 shows a comparison of CIT and MSC defective joint summaries by classification. According to the logging company documentation, this difference is due to the 8-mm spacing of the MSC feeler arms that possibly miss some of the SIPs identified by the CIT tool. As noted by logging company personnel, the MSC results also indicated a nonsymmetrical ID throughout the complete interval logged (i.e., from surface to 1458.2 m), as well as a small ovality and helical buckling as a result of a lack of cement support and a 10-mm casing offset at approximately 1062 m.

* Geology is approximate.

Figure 5. Schematic representation of 2011 SBT and CIT for Case 5.

Figure 6. Comparative summary of number of defective joints by classification obtained by CIT and MSC for Case Study 5 (2002).

5.1.3 Casing Imaging Tool

The CIT log surveyed in 2011 shows several SIP defects from surface to 950 m ranging from Class U to 4 and several penetrations. Penetrations (Class P defects) are at logged depths of 485.6, 820.2, 835.7, 850.2, 875.2, and 878.7 m. Reports from the logging company show that the casing was tested under pressure at 7 MPa and Joint Number 95 was found to have no penetration as had been observed in the CIT tool classification. The casing below 878.7 to 1458.2 m appears to be in relatively good condition, with defect codes ranging from Class U to Class 3. Most of these defects appear to be on the internal surface of the casing. Figure 5 contains the schematic representation of the CIT log.

5.1.4 Ultrasonic Radial Scanner

The URS tool was also run in this well, and in general, URS results can provide useful information about the ID of the casing and a detailed evaluation of the cement. However, the results obtained in this well were not used for any evaluation purposes because some challenges were encountered during the survey process, so the results were deemed unreliable by logging company personnel. Consequently, the URS log results for this well have been excluded from the casing and cement evaluation for this study.

5.2 Case Study 5 Results Summary

The casing integrity status of this well was evaluated by a CIT log and an MSC log in 2011. The results from the CIT log indicate several locations in the interval from around 400 m to about 900 m with severe pitting corrosion involving wall metal loss of 80% to 93%, specifically at depths of 485.6 (86%), 820.2 (93%), 835.7 (80%), 850.2 (80%), and 875.2 m (83%), although a pressure test conducted at the time this log was surveyed did not indicate the presence of a leak. The MSC log run just 2 days before the CIT log showed no serious corrosion problems, with 150 of 156 joints displaying only Class 2 pits, corresponding to a wall loss of 21%–40%. The large difference between MSC and CIT results appears to be due to the 8-mm feeler arm spacing in the MSC that potentially misses some of the pits that were evident in the CIT log. Thus the choice of logging tool in the investigation of casing integrity is very important for detection of defects and comparison of results.

The quality of the cement is excellent from the cement top at 1142 m to the bottom logged depth at 1455 m, although there are a few voids and microchannels from 1142 to 1230 m. Despite the observed small microvoids and microchannels, this interval is generally interpreted as providing zonal isolation.

6.0 DISCUSSION

6.1 Well Evaluation Details

Each of the case study wells has experienced various degrees of corrosion, as indicated by operator notes and the well logs. The casing and cement in Case Study 1 appeared to be in good condition in 1987 as logs indicated some Class 2 and 3 casing corrosion between 50 and 400 m and the cement had excellent bonding in the 1283–1409-m interval. After 2 years of WAG injection, a second log was run in 2002. This log indicated Class 2 and 3 casing corrosion throughout the wellbore, and cement had poor bonding in the 1100–1175-m interval (not previously logged). Operator notes for the Case Study 1 well indicated seals in the tubing were distorted from the CO₂ in 2003. It is common for injection wells to exhibit corrosion because of packer placements (Bachu and Watson, 2009). The force used to set a packer may dimple the casing, leading to increased corrosion in this area. In 2006, large chunks of scale were reported, and injection appeared to be entering old cemented perforations at 1375 m. In 2008, injection was again noted to be entering the old perforations at 1375 m, and the losses were greater than a 2007 RA (radioactive)/spinner survey. A caliper survey and operator notes in 2008 indicated corroded/missing casing from the tubing end to 1375 m. In this period of time, greater than 250,000,000 m³ of CO₂ was injected in the well. In 2010, pitting was found on several joints, and the tubing was sent off to be inspected shortly before abandonment began. The well was abandoned in November 2010 because the wellbore casing integrity was no longer suitable for CO₂/WAG injection. Casing corrosion for the upper part of the wellbore (i.e., above 1100 m) was not known after the 2002 log because the 2008 casing survey focused on the bottom of the well (i.e., 1336–1376 m) and no other casing evaluation logs were conducted.

The Case Study 5 well was evaluated in 2011 using multiple log types that allow full assessment of both the internal and external surfaces of the casing and the quality of the cement. Prior to the recent well logs, there had been no logging to evaluate the corrosion status in the well, but there was a corrosion-related tubing leak above the PSN in 1992 reported in the well data files. The CIT log was used to assess the internal and external surfaces of the casing; the MSC log surveyed only the internal surface of the casing, thus providing two data sets for the internal casing surface. The MSC log results indicated no serious corrosion problems, with 150 of 156 joints displaying only Class 2 pits corresponding to wall loss of 20%–40%. On the contrary, the CIT log indicated several locations in the interval from around 400 m to about 900 m with severe pitting corrosion involving wall metal loss ranging from 80% to 93%, specifically at depths of 485.6 (86%), 820.2 (93%), 835.7 (80%), 850.2 (80%), and 875.2 m (83%). The improved quality of the internal casing below 900 m may be a result of the pumping fluid level in the well, and the lack of a packer allows the casing/tubing annulus to be open to the atmosphere, which enables efficient pumping of the well. A pressure test conducted at the time this log was surveyed did not indicate a mechanical integrity issue. The large difference between MSC and CIT results appears to be due to the 8-mm feeler arm spacing in the MSC tool that potentially misses some of the pits that were evident in the CIT log, thus underscoring the importance of careful choice of logging tool in the investigation of casing integrity.

The quality of the cement was found to be generally in good condition, with good bonding to casing and formation in the lower wellbore from TOC at 1142 m to the bottom logged depth at 1455 m. Despite the observed small microvoids and microchannels, this interval is expected to be capable of full zonal isolation.

6.2 Well Comparison

Both case study wells are in close proximity; therefore, the geology is similar, although the formation properties such as formation fluids may vary. The case study wells are also similar in their spud date (i.e., within a narrow window of time from 1957 to 1962), and thus their drilling and completion procedures are similar. Both case study wells were initially completed as a production well. Case Study 1 then transitioned between water and WAG injection (see Table 3). Case Study 5 has been on oil production since completion in 1962 to suspension in 1995.

A comparison in the wellbore evaluation is presented in Table 7. In Case Study 1, casing corrosion appears to be more severe in the lower wellbore just above the production/injection perforations interval, whereas in Case Study 5, internal corrosion is found throughout the wellbore, with the more severe corrosion above 950 m.

External corrosion severity tends to decrease, in general, with depth in Case Study 1. The external corrosion severity is consistent with observed better cement quality in the lower wellbore that offers better protection to the external casing surface. Case Study 5 had limited observed external corrosion, because the logging tool that was used cannot detect external corrosion.

Table 7. Comparison of the Case Study Wells

Case Study Well	Casing Integrity	Cement Quality	Corrosion Severity	Cum. CO₂ Injected, m³	Cum. Water Injected, m³
Case Study 1	Corrosion internally and externally throughout wellbore; bottom 55 m of casing plugged off	Good cement bond below TOC (1133 m), zonal isolation possible in lower wellbore	Internal increase slightly from top to bottom of wellbore, but external decrease	>263,000,000	>741,000,000
Case Study 5	Internal corrosion throughout most of the wellbore, with more corrosion above 950 m	Good cement bond below TOC (1142 m) with possible effective zonal isolation	Internal oscillate with depth	N/A	N/A

The Case Study 5 status of more widespread corrosion was a bit anomalous because the well has neither been used for water injection nor CO₂. It does suggest that produced fluids may have accelerated corrosion or other contributing factors such as galvanic corrosion; sulfur-reducing bacteria, which typically feed on organic matter such as crude oil; and iron bacteria. These known corrosion mechanisms may potentially be involved. Because multiple large pits with 80%–93% wall loss occur relatively close to the surface casing, i.e., within the 400–900-m interval, it is plausible that stray current corrosion mechanisms could be a contributing factor to what is observed in Case Study Wells 1 and 5. However, laboratory analysis of the casing would be needed to fully substantiate these suggestions and to pinpoint specific mechanisms.

7.0 CONCLUSIONS

The wells chosen as case studies for this project provided some insight into casing corrosion in a well environment that has experienced CO₂ injection, as well as one well that has been exclusively an oil-producing well. In Case Study 1, the severity of internal casing corrosion increased near the lower sections of the well near the existing production perforations, while internal casing corrosion in Case Study 5 was greater above 950 m. The increase in corrosion for Case Study 1 is explained by injected fluids, location of packers, produced fluids, and the corrosive environment that is present in the perforated area of a well. In Case Study 1, the entire lower section of casing was completely corroded during the 6-year time period when CO₂ was injected; however, this was located below the packer and exposed to formation fluids and CO₂. The loss of casing in this area eventually led to the abandonment of the well because it could no longer be used for injection activities. In general, zones with effective barriers (e.g., isolated annular space coupled with good cement bond and zonal isolation) experience little degradation, whereas areas exposed to reservoir and injected fluids at high-flow velocities experience accelerated corrosion and cement degradation. Case Study 5 exhibited more generalized corrosion in an environment that did not experience injected fluids. Case Study 5 may have been

influenced by corrosion created by sulfur-reducing bacteria, iron bacteria, and stray current. Laboratory analysis would be required to elucidate these potential mechanisms. While the injection of CO₂ may affect casing corrosion rates, this study indicates that other contributing factors also need consideration.

8.0 ACKNOWLEDGMENTS

The authors are grateful to PTRC and the U.S. Department of Energy for funding the subject work. The authors would also like to acknowledge the support of Cenovus for providing access to well files and log documents.

9.0 REFERENCES

- Bachu, S., Faltinson, J., Hauck, T., Perkins, E., Peterson, J., Talman, S., and Jensen, G., 2012, The basal aquifer in the prairie region of Canada—characterization for CO₂ storage: Final report for Stage I (Phases 1 and 2), Alberta Innovates Technology Futures.
- Bachu, S., and Watson, T.L., 2009, Review of failures for wells used for CO₂ and acid gas injection in Alberta, Canada: ScienceDirect, p. 3531–3537.
- Bradshaw, J., Bachu, S., Bonijoly, D., Burruss, R., Holloway, S., Christensen, N.P., and Mathiassen, O.M., 2007, CO₂ storage capacity estimation—issues and development of standards: International Journal of Greenhouse Gas Control, v. 1, no. 1, p. 62–68, doi:10.1016/S1750-5836(07)00027-8.
- Brondel, D., Edwards, R., Hayman, A., Hill, D., Mehta, S., and Semerad, T., 1994, Corrosion in the oil industry: Oilfield Review, v. 6, p. 4–18.
- Celia, M.A., Bachu, S., Nordbotten, J.M., Gasda, S.E., and Dahle, H.K., 2004, Quantitative estimation of CO₂ leakage from geological storage—analytical models, numerical models, and data needs: Proceedings of the 7th International Conference on Greenhouse Gas Control Technology, Vancouver, Canada.
- Choi, T.-S., Young, D., Nešić, S., and Gray, L.G.S., 2013, Wellbore integrity and corrosion of carbon steel in CO₂ geologic storage environments—a literature review: International Journal of Greenhouse Gas Control, v. 16, no. 1, June 2013 p. S70–S77.
- Hamling, J.A., Bremer, J.M., Lindeman, C.D., Klapperich, R.J., Smith, S.A., Sorensen, J.A., Steadman, E.N., and Harju, J.A., 2011, Subtask 1.3—evaluation of geophysical technologies for application to CCS: Final report (March 1, 2010 – February 28, 2011) for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-08NT43291, EERC Publication 2011-EERC-02-09, Grand Forks, North Dakota, Energy & Environmental Research Center, February.

- Hawkes, C., Gardner, C., Watson, T., and Chalaturnyk, R., 2011, Overview of wellbore integrity research for the IEA GHG Weyburn-Midale CO₂ monitoring and storage project: Energy Procedia 4, p. 5430–5437.
- Hitchon, B., Ed., 2012, Best practices for validating CO₂ geological storage—observations and guidance from the IEAGHG Weyburn–Midale CO₂ monitoring and storage project: Chapter 7, Sherwood Park, Alberta, Canada, Geoscience Publishing.
- Intergovernmental Panel on Climate Change, 2005, Special report on carbon dioxide capture and storage: Cambridge, United Kingdom, and New York, Cambridge University Press.
- Sacuta, N., Young, A., and Worth, K., 2016, International Energy Agency (IEA) greenhouse gas (GHG) Weyburn–Midale CO₂ monitoring and storage project: Final Technical Report to U.S. Department of Energy, in press.