St. Flavien Facility

Review of Wells and Recommendations for Well Interventions
March 2, 2022

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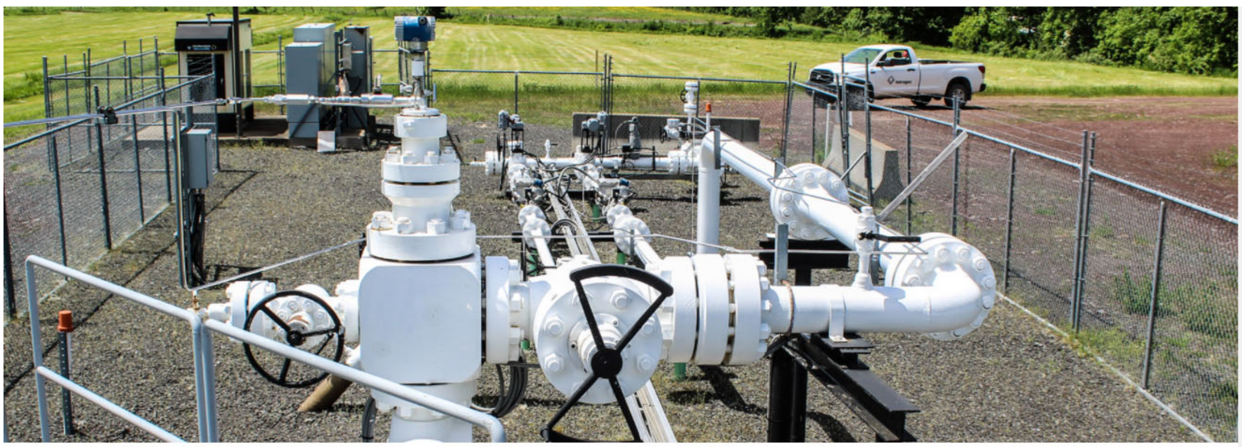

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ACRONYMS

Acronym	Description
AER	Alberta Energy Regulator
BC OGC	British Columbia Oil and Gas Commission
BOP	Blowout Preventor
CSA	Canadian Standards Association
EUE	External Upset End
MOP	Maximum Operating Pressure
OH	Open Hole
SFL	St. Flavien

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EXECUTIVE SUMMARY

Behr Integrated Solutions Inc. (Behr) was engaged to conduct a review of the wells in the St. Flavien field. There are a total of nine (9) vertical wells and six (6) horizontal wells in the field. Four of the nine (9) vertical wells are used for observation purposes.

The status of each of the wells was reviewed and workover recommendations including timeline estimates to complete the work were made. The priority to conduct the work on wells in the St. Flavien field was based on the following criteria, listed from most important to least important:

- Indications of a wall-thickness loss of a primary barrier such as the production casing string.
- Wellbore or equipment limitations that prevent pressure tests from being conducted at a pressure of 10% above the expected operating pressure.
- Pressure communication between tubing and casing.
- Timeframe from the last casing inspection logging operation was conducted.
- Deliverability of the well.

The priorities established for the wells based on the above criteria are shown in the table below:

Well	
Name	Priority Ranking
[redacted]	4
	1
	9
	12
	7
	10
	5
	8
	11
	6
	2
	14
	3
	15
	13

These rankings are intended to help assign priorities for the order in which work is to be conducted. However, the order is not intended to be firmly followed as there may be commercial or logistical considerations that influence management priorities. For example, increasing the size of the tubulars and perforating the tailpipe in [redacted] could double the deliverability of the well from [redacted] m^3/d to [redacted] m^3/d. Consequently, management may wish to move this work forward.

Currently, there is no specific requirement in Quebec for gas storage projects to comply with CSA Z341. However, some jurisdictions either follow this standard or have similar requirements within their regulatory guidance and the guidance aligns with industry best practices.

Intragaz continuously monitors the annular pressure and conducts annual pressure tests. However, [redacted] and [redacted] cannot be fully pressure tested to confirm casing integrity because of pressure limitations of wellbore features. Specifically, [redacted] has a retrievable casing patch that is not intended to withstand a surface-applied pressure above 7 MPa. [redacted] and [redacted] have cement squeeze perforations in the annulus that should also not be tested above surface-applied pressures of 7 MPa. Finally, most of the wells in the St. Flavien field are at a point where casing inspection logs should be performed.

[redacted]

There are no known issues that were identified in this review that require urgent attention. However, development of a strategic timeline to complete the work outlined in this report is recommended.

Intragaz should make provisions to conduct work on all of the wells over the next 15 to 20 years. Ultimately, after this round of workovers is complete, the St. Flavien field will be compliant with the CSA Z341 standard. Afterwards, continued compliance with this standard is recommended.

INTRODUCTION

Behr Integrated Solutions Inc. (Behr) has been engaged by Intragaz Inc. (Intragaz) to review the status of the wells in the St. Flavien field and provide forward looking recommendations for well interventions. The review incorporates the following considerations:

- The status of the wells
- Monitoring results
- Regulatory requirements
- Standards and best practices.

From this information, an outline of the steps required for the well interventions has been prepared. Additionally, priorities for the order of the work have been set.

The specific steps of the workover may be amended when the schedule time of work approaches. The availability, type and proximity of services may influence procedural decisions. Additionally, new technologies may become available which could result in procedural changes. Regardless, the objective of the workovers will remain the same.

WELL STATUS SUMMARY

Intragaz currently operates nine (9) active vertical wells and six (6) active horizontal wells in the St. Flavien Field. These wells are associated with the Beekmantown formation which has three zones; the A, B and C zones. Some wells are also opened to the Trenton and Chazy formations; however, these intervals are inactive.

The following table outlines the formation:

Well	Trenton		Chazy		Beekmantown A		Beekmantown B		Beekmantown C	
Name	Perf/OH	Status	Perf/OH	Status	Perf/OH	Status	Perf/OH	Status	Perf/OH	Status
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Inactive | Observation Well | Tight (Short interval) | Storage Zone

As the table shows, some of the injection/withdrawal intervals involve open hole sections that may, in part, cross the lower portion of the Beekmantown A zone. However, the Beekmantown A is tight and does not have reservoir storage capacity. Most of the reservoir storage is contained within the Beekmantown B zone. However, [redacted] has perforations in both the Beekmantown B and C zones. [redacted] and [redacted] are observation wells with open-hole intervals in the Beekmantown B and [redacted] is an observation well with perforations in the Beekmantown C.

[redacted] was drilled into Beekmantown, but the lower zones were abandoned with cement plugs.

[redacted] and [redacted] have perforations in the Chazy and Trenton intervals, respectively. These intervals have been isolated with packer systems. For [redacted], a retrievable casing patch straddles the Chazy and for [redacted], retrievable packers have been placed on either side of the perforated interval. The Chazy and Trenton intervals are tight and, therefore, did not produce gas.

All the gas storage wells used for injection, withdrawal or observation are completed with tubing strings. Additionally, except for [redacted], all the wells are completed in the Beekmantown formations, and all of these wells have packers to isolate the tubing string from the annulus.

[redacted] is an observation well that is open to the Chazy/Trenton formation. This well does not have an isolation packer at the base of the tubing string. However, [redacted] operates at low pressure, generally below 8,400 kPa.

APPLICABLE REGULATIONS, STANDARDS AND BEST PRACTICES

Ultimately, regulatory requirements are the driver of practices that must be followed. Some regulations may reference standards or specify practices, in which case they become part of the regulation.

In principle, wells in conventional reservoirs used for gas storage are similar to producing gas wells from conventional reservoirs. The primary differences are the following:

- Producing wells deplete over time and have a predictable life span that is usually related to the economic limit of the production, whereas a storage well may be in service for an undefined period and the life span is most likely related to the economic limit of the well.
- Storage wells, particularly those that are used for injection, may have wellbore pressures that are above discovery pressure.
- Producing wells often have more corrosive environments in comparison to storage wells that are principally injecting and withdrawing consumer grade natural gas with high mole fractions of methane with limited amounts of carbon dioxide.

Some wells in a storage project initially had a producing status for sweet natural gas. For St. Flavien, these wells include [redacted] and [redacted]. The remaining vertical wells were drilled as delineation or exploration wells and eventually were converted to gas storage wells. All the horizontal wells ([redacted]) were specifically drilled for use as gas storage wells and have only been exposed to consumer grade natural gas.

The Ministry of Energy and Natural Resources regulates the exploration, production and storage of hydrocarbons in Quebec. The Petroleum Resources Act (Act) outlines general provisions to govern petroleum resources. The Act indicates that "*All work performed under this Act must be performed in accordance with generally recognized best practices for ensuring the safety of persons and property, environmental protections and optimal recovery of the resource*". This statement is quite broad and requires interpretation of "recognized best practices". Certainly, regulatory references to requirements in other jurisdictions, such as Alberta and British Columbia, provide a foundation of best practices.

In general terms, chapter H-4.2,r.2 (Regulation respecting petroleum exploration, production and storage on land) requires that programs are signed and sealed by a qualified engineer.

In Alberta, Directive 51 addresses Injection and Disposal wells – Well Classifications, Completions, Logging and Testing Requirements. This directive is a regulatory requirement. Under this regulation, wells that are used to inject hydrocarbon gas qualify as Class III wells. Class III wells require the following:

- Hydraulic isolation of the host zone
- Cement across useable groundwaters
- Surface casing below useable groundwaters
- Cement returns to surface (during the primary cement operations of the casing string) or a cement top locator when no returns were established
- Initial logging operations that confirm hydraulic isolation and that inspect casing
- An initial annulus pressure test and annual pressure tests thereafter
- A well summary/completion schematic

- A maximum allowable wellhead injection pressure where Pmax > 0.875(2Ypt)/(1.3*D), where:
  - Yp is the yield pressure
  - t is the remaining wall thickness
  - D is the nominal outside diameter.

Section 4.2 of Directive 65 addresses applications for underground gas storage in Alberta. There are no references to the CSA Z-341 within Directives 51 or 65 or other Alberta regulations. However, Directive 65 specifically notes that Directive 51 requirements apply to gas storage projects.

The Drilling and Production Regulation for British Columbia states in Section 80(1) that, "*A well permit holder of a well that is part of a special project for storage reservoirs designated under section 75 of the (Oil and Gas Activities) Act must construct and operate the well in accordance with CSA Standard Z341.*"

Section 16 of the BC Drilling and Production regulation indicates the following:

- that injection must be through tubing
- that a packer be set in the well as near as practical above the injection zone, and
- that the annulus be filled with a corrosion inhibited fluid.

Saskatchewan's Ministry of Energy and Resources provides guidance indicating that, "*A storage project means a development for the storage of hydrocarbon in underground reservoirs and salt caverns, and the disposal of wastes in salt caverns. The applicant shall use the latest CSA (Canadian Standards Association) Z341, for the design, construction, testing, operation, maintenance and repair of underground hydrocarbon storage and cavern waste disposal projects in Saskatchewan.*"

In summary, BC and Saskatchewan require compliance to CSA Z341, while Alberta does not. However, Alberta does have specific rules related to injection operations and does reference the same equations in Directive 51 to those outlined in the CSA standard, at least for initial operations. However, the frequency of follow up logging operations is not specified in the Alberta rules, but annular pressure tests are required annually.

Overall, compliance to the CSA Z-341standard provides a reference point for best practices. CSA Z-341 does not require a packer. Instead, the standard changes recommended frequency of casing inspection logs. Specifically, CSA suggests a minimum logging frequency of twenty (20)-year intervals for wells with packer completions. Without a packer, CSA suggests a minimum logging frequency of ten (10)-year intervals.

For packer completions, CSA suggests a minimum pressure testing frequency of ten (10) years after a casing inspection log and five (5) years subsequently.

Intragaz has extended the logging frequency, given the complexity of operations to pull tubulars, particularly on wells with specialty tubulars. However, to address this extension of time between logs, Intragaz has increased the pressure testing frequency and is conducting annual tests. Additionally, Intragaz has equipped the wellheads with continuous pressure sensors that monitor the tubing/casing annulus and alarm with abnormal pressure changes.

The workover priority ranking discussed in subsequent sections of this report addresses factors such as pressure test results and time since the last casing-inspection log. Also, CSA doesn't suggest annular monitoring where as Intragaz continuously monitors annular pressure with a transducer.

CASING INSPECTION

CSA Z341 and Modified B31-G

The CSA formula has two values of significance: Py and Pmax.

Py = 0.875 x Yp x 2t/OD where Yp is the minimum yield strength of the steel and t is the wall thickness of the casing.

Pmax = Py/1.3

The formula for Py is the same as the API formula for determining the burst pressure for casing. However, the value of t in the API formula is the manufactured wall thickness while the value of t for the CSA formula is the remaining wall thickness at the point of the anomaly. The factor “0.875” within the formula is intended to accommodate allowable manufacturing variances in wall thickness of up to 12.5%. Both the API formula and the CSA formula are based on a generalized wall thickness.

The CSA formula then applies a 1.3 times safety factor to determine the Pmax value. Casing inspections are conducted by a casing inspection log that identifies wall thickness or by a pressure test.

In concept, CSA Z341 states that if a well is operating below Py, then casing inspection logging intervals of wells with tubing completions (with isolation packers) can be spaced by twenty (20)-year intervals. Additionally, for wells operating below Pmax, the next pressure test must be within ten (10) years and for wells operating below above Pmax but below Py, the next pressure test must be within five (5) years. Inspections conducted by a pressure test must then be followed by another pressure test or an inspection log within five (5) years.

Finally, if a well is operating above Py, then CSA Z341 stipulates that the storage zone is to be isolated and remedial work is to be conducted.

Because the CSA formula for the determination of Py is based on a full circumference wall thickness reduction, it is very conservative in nature. However, for pit-type corrosion, the wall thickness reduction is not circumferential but rather localized. Consequently, the thicker wall surrounding the pit provides additional burst resistance.

The modified B31G formula incorporates dimensional characteristics of the anomaly for determining a safe operating pressure (Psafe). However, the Psafe value is based on the manufactured wall thickness of the casing and does not adjust for allowable manufacturing variances. Therefore, Psafe based on the modified B31-G calculation may overstate the burst pressure of the casing if the pit occurs at a point where the actual wall thickness is less than the design wall thickness, given that casing wall thickness can be as low as 87.5% of the design wall thickness and still within the allowable API tolerance. Arguably a 0.875 factor could be applied to the modified B31G formula to accommodate for the possibility that a pit of interest has occurred at a point where the casing wall was on the thin side allowable API range for the casing wall thickness.

Logging summary

Except for well [redacted], which has never been logged, casing inspection logs have been run on all the wells, although it has been more than twenty (20) years since the last log was run on some wells. In general, the casing condition is very good. However, [redacted] has a [redacted] wall-thickness reduction at a depth of [redacted] m. All wells, excluding [redacted] and [redacted], are completed with tubing strings with packers and are operating below the CSA calculated value of Pmax. Therefore, these wells meet the CSA criteria for casing inspection logging intervals of twenty (20) years. The following table summarizes the logging results:

Well	Pressure Data		CSA Compliance					Safety Factors	
	Max. operating pressure	Last pressure used for testing	New Prod Csg Y.S. kPa)	W.T. Loss %	Py (kPa)	Pmax (kPa)	MOP (kPa)	API Design	CSA Z341
[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Because well [redacted] does not have a packer, the CSA requirement for logging intervals is ten (10) years. However, this well operates below 8,400 kPa, well below the burst rating of the casing of 34,340 kPa. Consequently, the priority to complete work on other wells supersedes this well, as discussed later within this report.

For [redacted], using the CSA 341 formula, Py calculates at 13,596 kPa and Pmax is 10,458 kPa. Using the modified B31G formula, Psafe for [redacted] is 33,980 kPa. If we apply a 0.875 factor to accommodate for the possibility of a reduced manufactured wall thickness at the point of the anomaly, then the adjusted Psafe would be 29,732 kPa. [redacted]

[redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]

[redacted]

- [redacted]
- [redacted]

RECOMMENDATIONS OF WELL INTERVENTIONS

The following table provides a maintenance overview for the next sequence of well workovers.

Well		Workover Objective
Name	Status	
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Intragaz has been confirming casing competency on most wells through annual pressure tests. This exceeds the CSA Z341 standard of conducting pressure tests every five (5) years (or within ten (10) years after a well has been logged). Annual tests represent a best practice and aligns with packer isolation testing requirements in Alberta.

Logging operations with flux-leakage tools (such as Baker's HR Vertilog or Schlumberger's PAL) help to understand casing integrity and identifying potential corrosion sources. These tools identify internal and external defects. However, they are interpretive and may be affected by scale on the pipe, tool setup or external equipment such as centralizers. Consequently, they are useful to identify areas to watch and help understand if corrosion is advancing at a given spot. Ultimately, the pressure test to 1.1 times the maximum operating pressure is definitive information that the casing can withstand operating pressures at the time of the test.

Ultimately, the intent of the workovers is to ensure that Intragaz continues to safely operate the wells. The recommended workovers could reasonably take between fifteen (15) and twenty (20) years to complete. After this cycle is complete, it is recommended that annual pressure tests be conducted and that wells be logged with casing inspection tools about ever twenty (20) years.

PRIORITY OF WORK

The priority of work is based on several factors as follows:

- The most important priority ranking for workovers at St. Flavien relates to the possibility of a loss of containment of a primary barrier such as the production casing string (generally determined from a casing inspection log).
- Wellbore or equipment limitations prevent pressure tests from being conducted at a pressure of 10% above the expected operating pressure.
- Pressure communication between tubing and casing.
- Timeframe that the last casing inspection logging operation was conducted.
- Deliverability of the well.

In general, the above list is in order of priority. However, discretion should be appropriately applied when setting the priorities. This report assigns scoring values and weight factors for the scores. This process helps assign a ranking to establish the order in which work should be conducted. Nonetheless, factors such as proximity of certain services and alignment of service requirements between wells may influence the specific order in which operations are conducted.

Potential loss of containment - log analysis (weighting factor 5)

The depth of a casing anomaly has relevance in the importance of resolution. The formation strength in the St. Flavien area is very high. Fracture gradients are more than 30 kPa/m. If a hole develops in the casing string, in absence of permeability across from the hole, the pressure in the wellbore will be contained by the formation if the wellbore pressure is below the fracture gradient. Based on a fracture gradient of 30 kPa/m and a maximum operating pressure of 20,000 kPa, the development of a hole below 667 m (20,000 kPa/30 kPa/m) would not result in a sustained propagation of a fracture. Arguably, if tubing failed near surface and the annulus was full of fluid, the annulus fluid could be pushed into the formation until the gas pressure plus hydrostatic balanced the fracture gradient. At depths below 1000 m, the formation would support the full operating pressure plus the hydrostatic pressure. Between 667 m and 1000 m there could be a temporary feed of fluid until the formation no longer continued to propagate a fracture system. In summary, the development of corrosion sites above 667 m should be addressed with highest priority, corrosion sites between 667 m and 1000 m should be addressed with moderate priority and sites below 1000 m should be monitored but with a lower priority. Within those categories, if the CSA Py value is below the working pressure, then the ranking should be higher. The following table provides the score criteria for logging anomalies:

Depth	Py	Score
No anomalies	≥20000 kPa	0
Below 1000 m	≥20000 kPa	1
Below 1000 m	<20000 kPa	3
667 m - 1000 m	≥20000 kPa	4
667 m - 1000 m	<20000 kPa	6
Above 667 m	≥20000 kPa	8
Above 667 m	<20000 kPa	10

Pressure test limitations (weighting factor 4)

If wellbore equipment limitations prevent annulus pressure tests from being conducted to 1.1 times the operating pressure, then a higher score is assigned to the well, particularly if the time from the last assessment is greater than ten (10) years. Additionally, the burst rating of the casing is considered in the ranking as casings with lower burst ratings should have a higher priority. The following table outlines the score criteria for pressure testing capability:

Pressure test to 1.1 x MOP available (Y/N)	Time since last full pressure test?	Score (Casing Burst ≤ 1.5 x MOP)	Score (Casing Burst between 1.5 x MOP and 3.0 x MOP)	Score (Casing Burst ≥ 3.0 x MOP)
Y	No requirement	0	0	0
N	<10 years	6	3	1
N	≥ 10 years	10	5	2

Tubing/Annulus communication (weighting factor 3)

The score related to communication between the tubing and the annulus is as follows:

Pressure test to 1.1 x MOP available (Y/N)	Time since last full pressure test?	Score (Casing Burst ≤ 1.5 x MOP)	Score (Casing Burst between 1.5 x MOP and 3.0 x MOP)	Score (Casing Burst ≥ 3.0 x MOP)
Y	No requirement	0	0	0
N	<10 years	6	3	1
N	≥ 10 years	10	5	2

As the table indicates, evidence of communication between the tubing and annulus is more relevant for wells that have a lower burst rating in comparison to the maximum operating pressure.

Some wells have minor pressure communication between the tubing and annulus. Typically, the communication is minimal, and the pressure will bleed off to zero without sustained flow. Additionally, a casing pressure test can be conducted on these wells. For these wells, the tubing is performing as an effective well-control barrier.

However, if a significant failure in isolation between the tubing and casing occurred, then the urgency for a remedial workover would be increased. For example, if a hole developed in the tubing, then the casing would be subject to well operating pressures. In this scenario, the well would be operating similar to a casing completion and a pressure test of the casing would likely be more difficult. The cause of the failure should be considered when assessing the remedial timing. If the failure is a result of corrosion on the tubing, then the casing barrier may also have corrosion issues and inspection of the casing should be expedited.

[redacted]

Time since last casing inspection log (weighting factor 2)

The score related to the time a casing-inspection log was last run on the well is indicated below:

Years since last log	Score
< 15 years	0
< 20 years	3
≥ 20 years	8
Never logged	10

As the table indicates, the duration of time since the previous log affects the score. However, the weighting factor (of 2.0) is low in comparison to other measures previously described.

Well deliverability (weighting factor 1)

Because the deliverability of a well is unrelated to a cause of a failure or the ability to assess the probability of a failure, it is given the lowest weighting factor of one (1) when considering the priority to conduct well operations. Nonetheless, if a well control event occurred, higher deliverability wells are more problematic. Therefore, higher scores are assigned to higher deliverability wells as follows:

Deliverability $10^3 m^3/d$	Score
No sustained flow	0
0<AOF≤50	2
50<AOF≤200	5
200<AOF≤1000	8
AOF > 1000	10

The following table provides a general ranking of the overall workover priority:

Well	Criteria Summary					Criteria Score					Weighted Average Score	Priority Ranking
	Log Summary	Pres. Test Summary	Tubing Annulus Comm. Summary	Time since last log (as of July 2021)	AOF (10^3m3/d)	Log Sum. Score	Pres. Test Score	Annulus Comm Score	Last Logged Score	AOF Cat. Score		
						Weighting Factors 5	4	3	2	1		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The priorities shown above are based on the scoring criteria. These should be reviewed as an indication of the order that workovers should be conducted. However, there may be logistical reasons or commercial reasons to shift some priorities. For example, certain equipment to handle tubulars may be in proximity to St. Flavien and may influence the order in which some operations are conducted. Similarly, larger BOPs (which must be shipped from Alberta) are needed for operations on [redacted] and [redacted]. Therefore, these jobs may be scheduled in back-to-back sequence. [redacted] also requires larger BOPs. However, this job should be the last priority and could be deferred.

Ultimately, it is recommended to conduct the workovers over a manageable timeframe with the ultimate objective of scheduling the following round of workovers to meet CSA Z341 requirements.

The summary of operations is intended to achieve the workover objectives described in the following table:

Well		Workover Objective
Name	Priority Ranking	
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

CONCLUSIONS

Each of the wells in the St. Flavien field has been reviewed. Based on this review, priorities have been assigned to conduct workovers.

Quebec's regulatory requirement for gas storage facilities is to comply with "*generally recognized best practices*". The recommendations in this report are aligned with industry best practices and are based on the CSA Z-341 standard and regulatory guidance from other jurisdictions.

Most of the wells in the St. Flavien field should be logged primarily because the specified time between casing inspection logs is overdue as per CSA standard. However, Intragaz exceeds the CSA requirement of a pressure test by conducting annual pressure tests and conducting continuous pressure monitoring on the wells with packer completions.

Casing inspection logging operations are complex as they require workovers involving the use of service rigs, specialized equipment and tubular tripping operations to prepare the wellbore for the logging operations. Because of the remoteness of the St. Flavien field to most oilfield service centres, workovers to trip tubulars are logistically complex and costly. Additionally, workovers that involve tripping tubulars have additional risks in St. Flavien, in comparison to operations near oilfield centres, as unforeseen complications that may arise during a workover may require the mobilization of distant services and cause delays.

[redacted]

There are no known issues that were identified in this review that require urgent attention. However, development of a strategic timeline to complete the work outlined in this report is recommended.

Intragaz should make provisions to conduct work on all of the wells over the next fifteen (15) to twenty (20) years. Ultimately, after this round of workovers is complete, the St. Flavien field will be compliant with the CSA Z341 standard. Afterwards, compliance with this standard is recommended.