Pointe-du-Lac Facility

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

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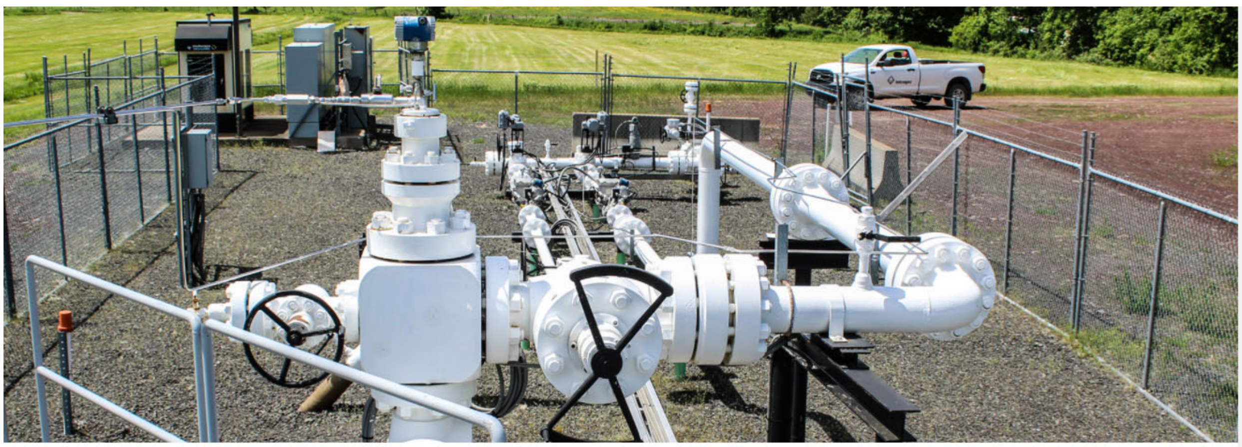

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ACRONYMS

Acronym	Description
BOP	Blowout Preventor
CSA	Canadian Standards Association
EUE	External Upset End
MOP	Maximum Operating Pressure
OD	Outside diameter
OH	Open Hole
PDL	Pointe-du-Lac

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EXECUTIVE SUMMARY

Behr Integrated Solutions Inc. (Behr) was engaged to conduct a review of the wells in the Pointe-du-Lac (PDL) field and provide forward looking recommendations for well interventions. Given the lack of specific regulatory guidance or references to best practices in Quebec, this assessment relies on good engineering principles. The PDL gas storage reservoir is used for injection and withdrawal operations from the high permeability Lotbinière Sand. There are also some observation wells in in the St. Pierre sand, which is approximately 30 m above the Lotbinière sand. Maximum wellhead pressures are low compared to typical gas storage and are about 740 kPa throughout the field. The reservoir is shallow and its depth varies from well to well but is generally about 70 m to the top and the overall thickness is about 6 m. The deepest well, [redacted], has a total depth of 133.0 m. Minor gas migration occurs in some of the wells. Nonetheless, it is important to assess the wellbore integrity to avoid loss of gas to other subsurface formations or the loss of well control.

The wells in PDL are considerably overdesigned for their maximum service pressure and, therefore, wellbore integrity is not an issue. The burst rating of the casing strings in the wells range from 15.93 MPa to 30.06 MPa. As such, the casing strings have a minimum safety factor of at least 20 times the maximum working pressure of the wells and safety factors up to 40 times on some wells. Consequently, significant corrosion would have to occur to reduce the casing rating below operating conditions.

This report includes recommendations to work on a select group of wells to verify assumptions that can be applied to all PDL wells. The reservoir permeability is very high and wellhead AOFs can be [redacted] m^3/d or more in some wells. Because the wells are very shallow and permeability is very high, these wells present well-control challenges as there is very little reaction time for service crews to respond to a loss of circulation or a kick. Therefore, unnecessary operations that involve the installation of BOPs and tripping of tubulars should be minimized on wells that are open to gas-filled portions of the reservoir.

Additionally, reservoir damage can occur when sand screens are pulled as the unconsolidated formation may collapse into the wellbore. This reservoir-damage concern further supports recommendations to minimize tubing tripping operations given that sand screens are attached to the production tubing in most wells in PDL and are pulled from the reservoir interval when the tubing is tripped.

Overall, the corrosion environment for the PDL wells is benign and casing inspections are expected to reveal favorable casing conditions. However, the tubing must be removed to log the production casing. Given the well-control and formation-damage challenges, the assessment of casing condition should be limited to a sampling of wells. [redacted] are the only wells in the field that do not have tubing strings in place. Well [redacted] is temporarily abandoned. Well [redacted] is completed in the aquifer portion of the reservoir and therefore cannot produce gas. Well [redacted] is cased and the Lotbinière is abandoned. The Gentilly till formation is perforated in this well but there is no pressure on the well. Because there is no tubing, this well can be logged without involving a service rig. However, some modifications that will involve a welder need to be made to enable access to the well. Assessing the casing conditions on wells [redacted] and [redacted] will therefore be easy as the work does not involve tripping tubulars. Casing inspection logs on these wells will provide an overall understanding of the condition of the casing strings in the field. If the pipe in these wells is in good condition, then the remaining wells are also likely to be in good condition.

Two observation wells [redacted] and a water injection well [redacted] are completed below the gas/water contact and are also water filled. Operations on these wells could therefore be conducted with minimal well-control risk and one or more of these wells could be considered for inspection to further validate the overall casing condition of the wells in PDL field. However, these wells are completed with tubing strings. A service rig would have to be positioned on these wells and the tubing would have to be pulled. The easiest of these three wells to service would be well [redacted] as it is equipped with 73 mm tubing while wells [redacted] are equipped with 139.7 mm tubing. Consequently, a service rig operation on wells [redacted] would require specialty tubular handing equipment whereas the tubing on [redacted] can be managed with standard service rig handling equipment. Additionally, the smaller tubing on [redacted] can more likely be pulled out of the sand reservoir without issue. Finally, well [redacted], like [redacted], is among the older wells as it was drilled in 1961. If the casing on wells [redacted] are proven to be in good condition, then these results will provide additional confidence that the remaining older and newer wells are also in good condition.

Finally, running a casing inspection log on the tubing string of any well with a 139.7 m OD tubing provides an opportunity to confirm an expectation that corrosion is not happening on the tubing string. If the tubing is free of internal and external corrosion, then internal corrosion on the production casing string is unlikely.

A number of other work objectives have been identified to maintain wells in good operating condition. These should be incorporated into a schedule of operations. They are also described below:

- Six wells with 6” ANSI-150 valves have master valves that are difficult to rotate. These valves could eventually fail. Five of the wells ([redacted]) have gas pressure and, therefore, cannot be removed without killing the well. It is therefore recommended to place a second master valve above the existing valve to ensure the well can be closed in whenever needed. The sixth well, [redacted], is completed in the aquifer and has no pressure. Therefore, the existing master valve on this well can be removed and replaced with a new valve.
- One 4” ANSI-150 valve at well [redacted] should be removed and replaced. This well is completed in the St. Pierre aquifer and has a wellhead pressure of 170 kPa. This pressure can be bled off and the well can be filled with water so that it remains dead during the valve replacement.
- The [redacted] wellhead will have to be cut off to conduct logging operations as the existing valve is too small to allow the passage of casing inspection logging tools. The wellhead equipment should therefore be upgraded to include a 7.0625” full opening valve.
- Drilling out the upper plug on well [redacted] will reactivate the well as an observation well.
- Pulling the tubing and running a casing inspection log on well [redacted] (the water injection well) will confirm whether corrosion is occurring from injection. The well can then be reconfigured with a packer to isolate the annulus between the tubing and casing and avoid corrosion of the casing.
- Pulling the tubing at well [redacted] will allow the annulus between the production casing and surface casing to be pressure tested. If the test fails, then a proper wellhead can be installed to isolate the annulus from the production casing. The final well configuration would no longer have tubing which would allow the well to be logged in future years without using a service rig.

- Abandoning well [redacted] will eliminate cross-communication from the Lotbinière in well [redacted] to the St. Pierre in well [redacted]. This would require a service rig so that a cement plug could be circulated across the zone.
- If well servicing operations are conducted on any well, then a casing inspection log will be run when the tubing has been removed.

[redacted]

In conclusion, logging operations are recommended to be conducted on sample wells [redacted]. Additionally, the tubing string on a gas well such as [redacted] should be evaluated as this information will present evidence of the internal corrosion environment within the production casing. If significant corrosion is evident in this logging program, then the nature of the corrosion should be evaluated to determine if the gas wells may also be subject to the same corrosion. For example, if corrosion is occurring at an air/water interface inside the casing, then gas-filled wells would not be subject to this corrosion process. Finally, servicing operations at wells [redacted] and [redacted] should be considered and well [redacted] should be considered for abandonment.

If corrosion concerns are identified, additional logging may be considered. A priority ranking is included in the report to provide guidance on the order that wells could be considered for logging. However, if the casing is shown to be in good condition in the previous logging program, additional logging operations would not be necessary at this time.

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. It is recommended that the non-service rig operations be grouped into continuous operations to avoid multiple mobilizations of related services. Similarly, the service rig operations should be also conducted as continuous operations to limit the mobilization of the major services to one mobilization.

The mechanical work that does not require specialized services, such as pumping out water from wellhead sumps and replacing or installing valves, should be incorporated into the general maintenance program Because the logging information is being used to evaluate potential corrosion issues in the field, the work should be conducted within the next few years. The service rig related operations are not time sensitive but should be conducted in the next five to ten years. Ideally, these operations should be scheduled when the appropriate servicing equipment is in the area.

INTRODUCTION

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

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

From this information, an outline of steps required for 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 scheduled 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.

APPLICABLE REGULATIONS, STANDARDS AND BEST PRACTICES

Regulatory requirements are typically the driver of practices that must be followed. Some regulations may reference standards or specify practices that become part of the regulation.

However, the PDL is a unique field as it is not a conventional gas storage operation covered by most regulations or standards. Specifically, PDL is unique with most wells less than 100 m in depth. Moreover, the wells specifically used for gas injection and withdrawal have reservoir depths of about 60 m. The casing strings in these wells have design safety factors ranging from 20 to 40 times the maximum operating pressure of the field. The risk of a casing failure is therefore minimal. Additionally, the permeability in these wells is in the order of darcies rather than millidarcies. As such, these wells do not easily support kill-fluid columns and the reaction time to recognize kick warning signs is minimal. Snubbing operations are also complicated as the production tubing generally includes screens and changes in tubular sizes that present complications in the equipment setup.

Given there are no other gas storage projects like PDL in Canada, references to best practices in other provinces is not applicable. However, good oil and gas field practices can be applied.

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 that 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".

In general terms, the regulation requires that programs are signed and sealed by a qualified engineer.

These statements do not specifically reference CSA standards or other standards and there are no equivalent gas storage operations to establish best practices. However, these wells are not dissimilar to shallow gas production such as coal-bed methane production. Coal bed methane wells and other shallow gas production projects do not have regulated requirements for casing inspection. Nonetheless, the life cycle of a gas storage project can extend for decades whereas most shallow gas projection projects have a comparatively short life.

Given the lack of specific regulatory guidance or references to best practice, the project must rely on good engineering principles. Because of the extended life of a gas storage project, it is my opinion that an assessment of casing condition should be conducted on a sampling of wells. If the well sample demonstrates the casing is in good condition in all sampled wells, then casing assessments would not be necessary in the near term for every well given the significant safety factors in place for every casing string in PDL. As follow-up evaluation programs are scheduled, the list of evaluated wells can be extended. New technologies may be introduced over time that change the nature of the evaluations.

CASING INSPECTION

Ideally, consistency in the casing inspection tools should be used. Tools can vary slightly from company to company, which could cause a variance of the interpreted depth of penetration of corrosion. Consequently, if different tools are used, the analyst could either overestimate or underestimate the rate of corrosion. Several companies offer high resolution flux-leakage tools. Given that Intragaz has not logged any of the PDL wells, any company could be chosen. However, there may be an advantage to utilize a logging truck when it is in the area for other Intragaz operations. Baker's HR Vertilog has been used in Intragaz's St. Flavien operations. It is therefore recommended to consider Baker among the logging candidates for PDL operations.

Some through-tubing casing inspection tools are on the market, which manufacturers claim can identify casing anomalies when the tools are run through tubing. However, Intragaz and other companies have tested these tools and have not found the results to be reliable. Consequently, it is my opinion that conventional flux-leakage tools are currently only meaningful if they can be run in casing without a tubing string in place. Nonetheless, through-tubing technologies may evolve and could be considered if improved results are demonstrated.

CSA Z-341 provides formulas for determining the allowable maximum operating pressure for a well. These formulas are very conservative. However, because the casing strings are overdesigned for the pressure application, there is no need to reference other casing integrity calculations such as B-31-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 that applies to the entire circumference of the casing.

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. Given that the casings in PDL have design safety factors between 20 and 40 times the working pressure, it is unlikely that CSA-derived working pressure restrictions would apply to wells in PDL.

In concept, CSA Z341 states that wells that do not have isolation packers should be logged every 10 years with interim pressure tests every 5 years. This time frame is not reasonable or practical for PDL on wells that are in communication with a gas zone, if logging programs are confirming that the wells are not subject to corrosion. Formation damage or well control issues that can arise by tripping tubulars on wells with communication to a gas zone introduces unnecessary risk. Instead, monitoring for corrosion on a sampling of wells should give Intragaz adequate confidence of the overall integrity of the wells in the field, provided the sample wells all show good casing condition. If some of the sample wells are presenting corrosion, then it would be important to understand what is causing the corrosion and if specific well configurations or environments are demonstrating vulnerabilities. Evidence of corrosion in wells being evaluated should lead to a detailed investigation that could eventually lead to a broadening of the well evaluations currently recommended in this report.

PDL operations are expected to be relatively non-corrosive and casing conditions are expected to be in good condition. This is supported by a Baker Vertilog that was run on well [redacted] in 2011. This log showed the casing to be in excellent condition. If this is confirmed on the sample wells and given the overall age of the field, subsequent logging operations can be extended. However, Intragaz should move to different wells as follow-up evaluation programs are introduced in order to increase the sample size.

WELL SUMMARY

There are 39 active wells in the PDL field. Of these wells, only three wells [redacted] are not completed with tubing strings to surface. The remaining wells are completed with tubing strings that range in size from 73.0 mm OD to 139.7 mm OD. Each of these wells have sand-control screens with slot sizes ranging from 0.008" to 0.018". These screens provide filtration of produced sediment.

The wellbore types fall into six categories as described below:

Type 1 These wells were completed with Baker liner hanger packers. They were all completed in 1990 and all have 139.7 mm tubing. Shear subs were placed below the hanger so that the tubing could be pulled even if the tailpipe below the liner hanger was stuck in the gravel pack below. There are 10 Type 1 wells in PDL.

Type 2 These wells are wells that do not have a packer or liner hanger of any type. The tubing is therefore hanging from the surface without any connection to the casing wall other than the gravel that is packed around the string. This is the most common completion type in the PDL field. These wells were drilled throughout the operational period including wells drilled as early as 1961 and as recent as 2009. Three of the wells [redacted] have shear subs above the screen. The remaining wells do not have shear subs. The tubing string sizes range from 73 mm to 139.7 mm.

Type 3 Well [redacted] is the only Type 3 well. Type 3 is a well where the tubing has been pulled, but the formation is still open to the wellbore. It appears that the tubing parted about 1.22 m above the base of the string when an attempt to pull the tubing was conducted. Likely, formation sloughing, or gravel packed around the tubing, prevented it from being freely pulled. However, it appears that some tubing movement occurred before it parted as the base of the tubing is about 4.32 m above the total depth. The top of the parted screen is now at 120.88 m, just slightly above the top of the Lotbinière at 121.19 m.

Type 4 Five Type 4 wells were drilled and completed between 1990 and 1996. These wells have inflatable packers above the screen and tubing string sizes ranging from 114.3 mm OD to 139.7 mm OD. Capillary tubes with a 6.34 mm OD, that were used to inflate the packers run along the outside of the tubing. These tubes present some challenges when pulling the tubing as conventional pipe rams will not close over the tube and the tubing must be spooled off or cut as the pipe is pulled.

Type 5 Well [redacted] is the only Type 5 well. This well has been temporarily abandoned with a bridge plug which was set at 53.3 m with a cement cap to about 49.4 m. The tubing has been pulled from the well and the wellbore is filled with inhibited water.

Type 6 Well [redacted] is the only Type 6 well. This well is an observation well with perforations in the Gentilly till. The well is open to the atmosphere but does not have a wellhead installed. Instead, there is a steel cap with a riser and 3" (76.2 mm) valve welded to the cap.

Table 1 summarizes the well identifiers that fall into each category.

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

All of the wells are completed in the Lotbinière with the exception of wells [redacted], which are completed in the St. Pierre and well [redacted], which is completed in the Gentilly till.

Seventeen (17) wells, shown in bold font in Table 1, are used for gas injection and withdrawal from the Lotbinière. The reservoir thickness in the gas injection/withdrawal wells is typically about 6 m and the top of formation depth in these wells range from 62.8 m to 71.3 m.

The maximum static wellhead pressure for the gas injection/withdrawal wells is about 740 kPa. Because of the shallow depth and low operating pressure, the maximum reservoir pressure is just marginally above the maximum wellhead pressure at about 744 kPa.

Most of the production casing strings in the wells are 177.8 mm OD. However, four wells [redacted] are equipped with 114.3 mm casing strings and two wells [redacted] have 193.7 mm casing strings. The burst ratings of the casing strings range anywhere from a low of 15.93 MPa [redacted] to a high of 30.06 MPa [redacted] This represents a safety factor ranging from 20 to 40 times the maximum operating pressure. Consequently, a casing failure resulting from operating pressure is highly unlikely unless severe corrosion exists.

There is minor gas migration around some of the wellsand. The cumulative gas migration flow rate has been declining with time from an average of about 100 m^3/d in 1993 to below 25 m^3/d in 2020. The gas migration is immediately adjacent to the casing and is collected through conductor pipe around the wellheads. Remedial operations to further reduce the flow would likely be unsuccessful and would involve complex and risky workover operations that could result in a well-control situation on some wells. Additionally, casing strings would have to be perforated for cement squeezes to be conducted. Consequently, the casing integrity would be compromised. Also, removal of the tubing string could result in reservoir damage. Given the minimal extent of the migration and that it is declining with time, it is not recommended to address the migration.

When the field is ultimately abandoned at the end of the operation, the migration will stop as the remaining storage gas will be fully withdrawn from the field.

There appears to be cross communication between the Lotbinière at well [redacted] and the St. Pierre at well [redacted]. To stop this communication, it is recommended to abandon well [redacted] by installing a cement plug across the entire open-hole section. This will require a service rig.

WELL SERVICING/INSPECTION CONSIDERATIONS

The priority to evaluate the casing condition on wells in the PDL field was based on the following criteria, listed from most to least important:

- Whether the well is water-filled or has an isolation bridge plug and can remain dead
- Whether a packer is in the wellbore
- Whether tubing is in the wellbore
- Whether the well is completed in the Lotbinière
- Whether wellhead is equipped to allow access with logging tools
- Difference in diameter of the tubing string and the casing string.

Ultimately, the objective of a well servicing program is to verify that wellbore integrity is suitable for the operations being conducted. Given that the casing strings are considerably over designed for the operational service pressures, it is unlikely that a casing failure would occur unless significant corrosion issues are identified.

In addition, operations to assess the casing condition can introduce a well control situation, depending on the wellbore configuration and whether it is in communication with gas or water. Because the PDL wells are very shallow, wellbores that are in communication with a gas zone can quickly lose kill fluids and kick. In these cases, service crews have very little time to see warning signs for a kick and appropriately respond to shut in the well. Therefore, operations to assess wellbore conditions on gas-filled wells should be avoided if wellbore conditions can be suitably assessed through other means.

Flux-leakage casing inspection logging tools can be run in a gas-filled or water-filled environment. Therefore, any well that does not have a tubing string in place and has wellhead equipment that will allow access of logging tools into the wellbore can be logged without killing the well and without exposing crews to unnecessary well-control risks.

Tubing can safely be tripped in wells that are completed in a water zone. In these wells, there is very little well control risk, provided the hydrostatic pressure of the water column is greater than the formation pressure. The first operational consideration relates to the ability to pull the tubing string out of the well. If the standoff between the production tubing and the casing or open hole is very tight, the likelihood that the tubing could be stuck in the wellbore is greater in comparison to a well where the tubing is much smaller than the casing or open hole. For example, wells [redacted] are all completed in water zones and all three have 177.8 mm casing. However, the tubing in [redacted] is 73 mm OD in comparison to the 139.7 mm OD tubing strings in [redacted] and [redacted] Therefore, the tubing in well [redacted] will more likely be pulled and rerun without operational problems in comparison to conducting these operations on wells [redacted]. Furthermore, the risk of formation damage is reduced if the tubing is pulled and rerun without engaging in extensive hole cleaning operations. Consequently, well [redacted] is the preferred candidate for **casing** logging operations, over wells [redacted]. However, logging the **tubing** for [redacted] or [redacted] would provide useful information about the general corrosion environment without having to trip the tubing.

The Annex provides a detailed overview of the well status. Information from this table was used to identify a ranking that incorporates the risk and the benefit of conducting operations on a well with the objective of understanding the casing integrity of the wells in the PDL field. A score of zero represents minimal risk and a positive benefit, scores from 50 to 100 represent a medium risk for the achieved benefit and scores above 100 represent wells that introduce relatively high risk for the achieved benefit.

Wells that are completed in a zone below a gas water contact or completed in a wet zone with no gas will be water filled. Provided the zone is sub-normally pressured (or at a pressure that is below the hydrostatic pressure of a freshwater column from surface to the zone depth), the well cannot flow. If the Lotbinière is at the maximum operating pressure, the water zone could be slightly above sub-normal pressures and therefore flow. However, when the Lotbinière pressure is below 650 kPa, the associated water zones should not flow.

Because the Lotbinière has very high permeability, working on wells with completion intervals that are within or partially within the gas zone can be difficult. Even with mud systems, fluid column stability can quickly be lost with the movement of tubulars or tools causing a loss of hydrostatic pressure. With the shallow depth of this formation, kicks can occur with very little warning time and rig crews may have difficulty shutting in the well. Consequently, the priority to conduct workover operations is focused on wells that are completed in water-bearing intervals. The following table shows the risk criteria. A weighting of 6 times is applied to this risk criterion.

Water-filled Criteria

Description (Weighting factor 6)	Risk Ranking
Water-filled zone or well secured with downhole plug	0
Partial or all gas-filled zone	10

Wells with packer devices in the well are more likely to create operational difficulties, particularly given the age of many of the wells. Therefore, a weighting of 5 times has been applied to this criterion.

Packer device on tubing

Description (Weighting factor 5)	Risk Ranking
Tubing hanging without packer	0
Packer device on tubing	10

Wells with no tubing in the well can be logged without necessarily involving a service rig, provided a minimum tool access diameter is greater that 139.7 mm. If the well is dead, then the wellhead can easily be modified for the logging operation if the wellhead valve diameter is too small for the tool. Additionally, not involving a service rig or moving tubing simplifies the workover operations. A weighting factor of 4 times has been applied to this criterion.

Tubing in well

Description (Weighting factor 4)	Risk Ranking
No tubing in wellbore	0
Tubing in well	10

Most of the wells in PDL have wellheads that allow the installation of BOPs and other servicing equipment. However, some wells have welded plates or other incumbrances that do not facilitate the easy installation of equipment. On these wells, plates may have to be cut off and wellhead equipment installed to facilitate the operation. Clearly, work of this nature would only be conducted on wells where it is assured that the well will remain dead. Other weighting factors address issues of the well being static. Therefore, a relatively low weighting factor of 2 times is applied to the wellhead configuration.

Wellhead configuration

Description (Weighting factor 2)	Risk Ranking
Wellhead configured for easy access	0
Wellhead modifications required for access	10

Wells that are completed in the Lotbinière have been given some priority over wells that have completions in other zones. A ranking of 1.5 times is applied, as indicated below.

Completion zone

Description (Weighting factor 1.5)	Risk Ranking
Completed in Lotbinere	0
Completed in zone other that Lotbinere	10

Finally, the clearance between the casing and the tubing or open hole can present operational difficulties in pulling the tubing. This is not considered to be a high-risk factor as the tubing will likely be easily pulled. However, a weighting factor of 1 times is applied as indicated below:

Tubing/casing clearance

Description (Weighting factor 1.0	Risk Ranking
Clearance between Casing ID and Tubing OD ≥ 30 mm	0
Clearance between Casing ID and Tubing OD < 30 mm	10

Tubingless Completions – Dead Well

The wells with the lowest risk ranking are [redacted]. Well [redacted] is temporarily suspended. The casing on this well can be logged without any intervention on wellhead equipment or downhole equipment. With the help of a picker truck, a logging truck can simply rig up to the wellhead and run the casing inspection tools.

Well [redacted] is similar to well [redacted], with low operational complexity. Unlike well [redacted], well [redacted] has open perforations to the Lotbinière, but these perforations are below the gas/water contact and the well does not have pressure on it. A logging truck can therefore rig onto the wellhead without running plugs or conducting a kill operation.

Well [redacted] is the next best candidate for operations as this well also does not have a tubing string. The lower Lotbinière zone at well [redacted] was abandoned but perforations have since been placed in the Gentilly till. The well is open to atmosphere and does not have any pressure. Some work would have to be done to expose the wellhead, which has a welded wellhead cap. This cap would have to be removed and a proper wellhead installed, which could be limited to a 177.8 mm bell nipple with a 177.8 mm ball valve. This work could be conducted without the involvement of a service rig.

Tubing Completions – Dead Well

Casing evaluations on the remaining wells are more complex and risky as service rig operations would be required to remove the tubing prior to logging. If logging operations on wells [redacted]

[redacted] and [redacted] confirm the good casing condition, then operations involving a service rig can be avoided at this stage.

The following table outlines the ranking results from this analysis.

Well	Status	Csg ID mm	Tbg OD mm	Delta ID/OD	Delta Rank	Tbg in Well Rank	Pkr in Well (Y/N)	Pkr in Well Rank	Comp. Zone	Comp Zone Rank	Water filled?	Water Filled Rank	W/H Access (Y/N)	W/H Access Rank	Overall Risk Rank
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

(NOTE: The four wells that are drilled down to the St. Pierre ([redacted]) are excluded from the above list as they not considered a priority for casing evaluation.)

The next candidate for casing evaluation is well [redacted]. This well has tubing, but without packer equipment. The tubing size is 73 mm, which enables a conventional service rig to pull the tubing without any special handling tools. Once the tubing is pulled, the well can be easily logged. One issue with [redacted] is that the tubing/production casing annulus is in direct communication with the cemented annulus between the surface casing and the production casing. Once the tubing is pulled, this cemented annulus could be pressure tested to confirm the pressure integrity of the cement. If the pressure test was successful, no further work would be required on the wellhead. If the pressure test fails and a leakoff down the cemented annulus is confirmed, then the 114.3 mm production casing could be tied back and extended above the surface casing stub. A casing bowl with a packoff, cover plate and vent assembly would be installed onto the surface casing and a bell nipple and tubing head would be installed onto the 114.3 mm production casing. During these operations, a casing inspection log should be conducted on the production casing. After the logging operations, the screen could be relanded across the Lotbinière and hung below a packer. The tubing above the packer would then be pulled before the wellhead is installed. This would allow future logging operations to be conducted without involving a service rig.

If corrosion is identified, a detailed investigation on the cause of the corrosion should be evaluated. Then the next best candidates for casing evaluation are wells [redacted]. These wells are similar to [redacted] as they are wells that are completed in the Lotbinière and have tubing strings in place. The primary difference is that the tubing strings in [redacted] and [redacted] are 139.7 mm and therefore require special handling equipment. However, these wells have a tighter standoff between the tubing and casing and may be more difficult to pull.

Service rig operations on the above noted wells with tubing completions are not recommended at this time but could be considered as primary candidates if corrosion concerns are identified and additional logging is recommended.

Gas Well Logging

While a logging truck with casing inspection tools is conducting the recommended program, an inspection of one of the gas-filled wells could be conducted on the tubing string. The purpose of this log is to confirm that corrosion is not occurring in the tubing of these gas-filled wells, with the inference that the casing surrounding the tubing likely also does not have internal corrosion as it is in the same environment as the tubing. Of course, this would not provide evidence about external corrosion on the casing. Any well with 114.3 mm or 139.7 mm tubing could be used as a sample well. Well [redacted] is proposed as a potential sample.

Other work recommendations

Intragaz has identified a number of other work objectives which could be incorporated into a schedule of operations. These include the following:

- Six wells with 6" ANSI-150 valves have master valves that are difficult to rotate. These valves could eventually fail. Five of the wells [redacted] have gas pressure and, therefore, the master valves cannot be removed without killing the well. Therefore, it is recommended to place a second master valve above the existing valve to ensure the well can be closed in whenever needed. The sixth well, [redacted], is completed in the aquifer and has no pressure. Therefore, the existing master valve on this well can be removed and replaced with a new valve.
- One 4" ANSI-150 valve at well [redacted] should be removed and replaced. This well is completed in the St. Pierre aquifer and has a wellhead pressure of 170 kPa. This pressure can be bled off and the well can be filled with water so that it remains dead during the valve replacement.
- The [redacted] wellhead will have to be cut off to conduct logging operations as the existing valve is too small for all the passage of casing inspection logging tools. Therefore, the wellhead equipment should be upgraded to include a 179.4 mm full-opening valve.
- Pull the tubing from well [redacted] so that the top of the production casing/surface casing annulus can be pressure tested. If the test fails, then a casing bowl with a packoff and cap assembly can be placed on the surface casing and a riser with a 103.2 mm flange can be placed on the production casing. A full opening valve can then be placed above the flange. The screen can be run back in and hung below a packer. The tubing above the packer

can be removed so that the well can easily be logged in the future without involving a service rig.

- Drilling out the upper plug on well [redacted] so that it can be used as an observation well. This operation will involve a service rig so that tubing can be run with drill collars and the plug drilled out. The wellhead should also be upgraded to have a 179.4 mm full-opening valve. A casing inspection log can be run on the well after the plug is drilled out if the well was not already logged during operations that do not require a service rig. A tubing string should not be placed in this well.
- Abandon well [redacted] to eliminate cross-communication from the Lotbinière in well [redacted] to the St. Pierre in well [redacted]. This would require a service rig so that a cement plug could be circulated across the zone. A casing inspection log should be run on the well prior to setting the abandonment plug.
- Run a casing inspection log on well [redacted] to assess whether corrosion is occurring. After logging the well, a packer should be placed in the well and the annulus should be circulated to inhibited water.

Remaining wells

The remaining wells have risk rankings over 100 as they represent wells that are in communication with gas and represent a higher risk to conduct well-servicing operations that involve the installation of BOPs and tripping tubulars given the potential for a well-control issue. If logging operations show that corrosion is minimal in the recommended workover candidates, then corrosion concerns on the remaining wells would also be considered minimal. Moreover, the gas-filled wells should have less corrosion than the water-filled (dead) wells as these latter wells may have exposure to oxygen if they have been left open to the atmosphere. If the wells recommended for inspection do not show evidence of corrosion, then the likelihood of corrosion existing on the remaining wells is minimal. A sampling of the remaining wells could be inspected in subsequent programs to verify that the wellbores are in good condition.

CONCLUSIONS

The PDL fieldoperates at a very low pressures and consists of wells that have casings with design burst ratings ranging from 20 to 40 times the operating pressure of the field. Consequently, the risk of a casing failure is minimal. However, a sampling of wells is recommended for casing inspection logging to provide additional assurance that the wellbore integrity in PDL continues to be sufficient for the operating conditions. Wells were ranked according to a priority criteria to help facilitate identification of the best candidates for logging operations. The priority to conduct workover operations is focused on wells that are completed in water-bearing intervals. A number of other work objectives could be incorporated into a schedule of operations. The following table provides an overview of recommended operations:

Well (s)	Status	Summary of Work	
[redacted]	[redacted]	[redacted]	Non-Service Rig Operations
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	Service Rig Operations
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
	[redacted]	[redacted]	

Minimal gas migration exists in the field. However, remedial operations are not recommended at this time as the migration rates are diminishing and procedures to address migration would compromise the casing integrity. At the end of gas-storage project life at PDL, the gas in place, including cushion gas, will be removed and any remaining migration will cease.

The mechanical work that does not require specialized services, such as pumping out water from wellhead sumps and replacing or installing valves, should be incorporated into the general maintenance program. Because the logging information is being used to evaluate general potential corrosion issues in the field, the work should be conducted within the next few years. The service rig related operations are not time sensitive but should be conducted in the next five to ten years. Ideally, these operations should be scheduled when the appropriate servicing equipment is in the area.

ANNEX – WELL DETAILS

				Production Casing						Prod. Tbg		Screen		Tbg. Packer		Zone			
Well	Status	Year Drilled	Comp. Type	OD mm	Wt. kg/m	Grade	Burst Mpa	SF	Setting Depth m	OD mm	Setting Depth m	OD mm	Interval from m - to m	Equipped with Packer (Y/N)	Depth	Completion Zone	Interval	Internal Total Depth m	
[redacted]	Observation	1964	6	177.8	25.3	H40	15.93	21.24	120.18	none						De Gentilly	40.78-41.78	61.78	[redacted]
[redacted]	Observation	1955	4	177.8	29.8	K55	25.79	34.39	55	114.3	75.77	114.3	64.19-68.37	Y	58.86	Lotbinere	61.5-75.5	83.42	[redacted]
[redacted]	Temp Aband.		5	114.3	14.1	H40	21.99	29.32	60.76	none						Lotbinere	63.0-70.6	49.4	[redacted]
[redacted]	Observation	1961	2	114.3	14.1	H40	21.99	29.32	65.19	73	80.33	66.7	69.0-75.26	N		Lotbinere	69.0-75.7	82	[redacted]
[redacted]	Observation	1961	2	114.3	?	?	?		?	73	27.14	60	18.52-21.77	N		St Pierre	?	29.99	[redacted]
[redacted]	Suspended	1961	2	177.8	25.3	K55	21.90	29.20	94.3	73	110.11	60.3	94.22-100.22	N		Lotbinere	99.9-102.4	~84	[redacted]
[redacted]	Observation	1961	2	177.8	25.3	K55	21.99	29.32	100.9	73	110.93	63.5	100.42-100.66	N		Lotbinere	100.8-106.0	112.3	
[redacted]	Observation	1957	2	177.8	25.3	K55	21.90	29.20	63.78	139.7	79.77	117.5	66.3-72.58	N		Lotbinere	66.2-75.6	~53	[redacted]
[redacted]	Observation	1961	3	177.8	29.8	J55	25.79	34.39	118.13	none		95.3	120.88-122.1	N		Lotbinere	121.2-132.2	120.68	[redacted]
[redacted]	Observation	1985	2	177.8	34.23	J55	30.06	40.08	67.4	88.9	85.3	92	73.48-75.71	N		Lotbinere	68.0-82.6	85.3	
[redacted]	Observation	1986	2	177.8	29.8	J55	25.79	34.39	69.8	139.7	84.11	142.9	72.82-79.08	N		Lotbinere	72.7-78.8	85.92	[redacted]
[redacted]	Gas Inj./with.	1986	2	177.8	29.76	K55	25.79	34.39	67.9	139.7	79.84	168.3	70.56-76.87	N		Lotbinere	70.0-75.7	80.8	[redacted]
[redacted]	Observation	1986	2	177.8	29.76	K55	25.79	34.39	67.5	139.7	95.45	143	70.34-76.6	N		Lotbinere	70.1-77.3	100	[redacted]
[redacted]	Gas Inj./with.	1990	1	177.8	25.3	K55	21.90	29.20	68.28	139.7	85.28	117.5	71.78-77.66	Y	65.97	Lotbinere	71.3-77.3	85.8	[redacted]
[redacted]	Observation	1990	1	177.8	25.3	K55	21.90	29.20	71.37	139.7	88.43	117.5	73.93-79.73	Y	66.64	Lotbinere	73.8-79.8	88.8	[redacted]
[redacted]	Gas Inj./with.	1990	1	177.8	25.3	K55	21.90	29.20	67.9	139.7	79.84	143	66.95-73.17	Y	59.23	Lotbinere	66.8-73.5	82.8	
[redacted]	Observation	1990	2	177.8	25.3	K55	21.90	29.20	65.66	139.7	86.19	117.5	68.39-77.05	N		Lotbinere	68.7-78.2	~55	[redacted]
[redacted]	Gas Inj./with.	1990	1	177.8	25.3	K55	21.90	29.20	63.9	139.7	81.94	117.5	65.44-74.64	Y	56.55	Lotbinere	65.6-72.3	82.9	
[redacted]	Observation	1990	2	177.8	25.3	K55	21.90	29.20	69.2	139.7	84	117.5	71.5-77.46	N		Lotbinere	71.0-75.7	~59	[redacted]
[redacted]	Gas Inj./with.	1990	2	177.8	25.3	K55	21.90	29.20	66.83	139.7	81.7	117.5	66.73-72.72	N		Lotbinere	66.7-72.7	81.7	[redacted]
[redacted]	Gas Inj./with.	1990	1	177.8	25.3	K55	21.90	29.20	62.62	139.7	79.72	117.5	65.32-74.8	Y	56.43	Lotbinere	65.1-72.8	80.82	[redacted]
[redacted]	Gas Inj./with.	1990	1	177.8	25.3	K55	21.90	29.20	65.87	139.7	77.79	117.5	66.67-73.00	Y	59.14	Lotbinere	66.8-73.4	80.7	[redacted]
[redacted]	Gas Inj./with.	1990	1	177.8	25.3	K55	21.90	29.20	64.93	139.7	79.5	117.5	66.4-72.7	Y	57.73	Lotbinere	66.0-73.1	80.76	[redacted]
[redacted]	Gas Inj./with.	1990	2	177.8	25.3	K55	21.90	29.20	59.7	114.3	78.98	114.3	62.8-72.7	N		Lotbinere	62.8-71.4	80.75	
[redacted]	Gas Inj./with.	1990	1	177.8	25.3	K55	21.90	29.20	63.75	139.7	79.36	117.5	67.01-73.27	Y	54.92	Lotbinere	67.0-73.0	80.57	[redacted]
[redacted]	Observation	1990	2	177.8	25.3	K55	21.90	29.20	22.95	139.7	40.29	117.5	23.79-33.54	N		St Pierre	25.7-36.0	44.54	
[redacted]	Observation	1990	2	177.8	25.3	K55	21.90	29.20	28.79	139.7	48.34	117.5	31.34-40.75	N		St Pierre	38.7-45.9	55.51	[redacted]
[redacted]	Gas Inj./with.	1990	1	177.8	25.3	K55	21.90	29.20	64.38	139.7	79.36	117.5	68.63-74.83	Y	56.51	Lotbinere	68.6-74.8	82.59	[redacted]
[redacted]	Observation	1990	1	177.8	25.3	K55	21.90	29.20	64.52	139.7	79.63	117.5	67.98-74.23	Y	55.89	Lotbinere	68.0-73.2	80.72	[redacted]
[redacted]	Gas Inj./with.	1990	4	177.8	25.3	K55	21.90	29.20	63.1	114.3	79.55	114.3	65.9-76.2	Y	63.45	Lotbinere	64.5-72.6	79.7	
[redacted]	Water Injection	1992	2	177.8	25.3	K55	21.90	29.20	75.02	139.7	90.9	117.4	77.43-83.80	N		Lotbinere	75.6-85.2	92.6	[redacted]
[redacted]	Observation	1992	4	177.8	25.3	K55	21.90	29.20	63.1	139.7	45.19	127	32.08-39.07	y	29	St Pierre	34.47-47.16		
[redacted]	Observation	1992	2	177.8	25.3	H40	15.93	21.24	67.45	139.7	85.76	114.3	69.67-76.53	N		Lotbinere	69.75-76.75	85.7	
[redacted]	Observation	1992	2	177.8	25.3	H40	15.93	21.24	87.75	139.7	112.71	114.3	69.67-76.53	N		Lotbinere	99.7-104.8	115.03	
[redacted]	Observation	1992	2	177.8	25.3	H40	15.93	21.24	100.52	139.7	112.23	114.3	108.64-112.23	N		Lotbinere	108.3-111.8	121.8	[redacted]
[redacted]	Observation	1994	2	177.8	25.3	K55	21.90	29.20	97.2	139.7	111.25	117.5	104.4-107.5	N		Lotbinere	110.2-111.9	122.9	[redacted]
[redacted]	Observation	1996	4	193.7	25.3	K55	28.54	38.05	88.86	127	102.19	114.3	94.8-98.23	Y	92.2	Lotbinere	94.72-97.72	107.72	
[redacted]	Gas Inj./with.	1996	4	193.7	25.3	K55	28.54	38.05	68.43	127	88.62	114.3	72.1-81.5	Y	69.09	Lotbinere	70.45-79.45	88.95	
[redacted]	Observation	2009	2	177.8	25.3	K55	21.90	29.20	97	114.3	113.63	103.9	105.54-111.83	N		Lotbinere	106.2-111.0	118.8	