Testing Alternative Products for Well Remediation and Decommissioning / Abandonment – Phase 1

Challenger Technical Services Ltd.

Resin

FINAL REPORT PREPARED FOR
PETROLEUM TECHNOLOGY ALLIANCE CANADA.

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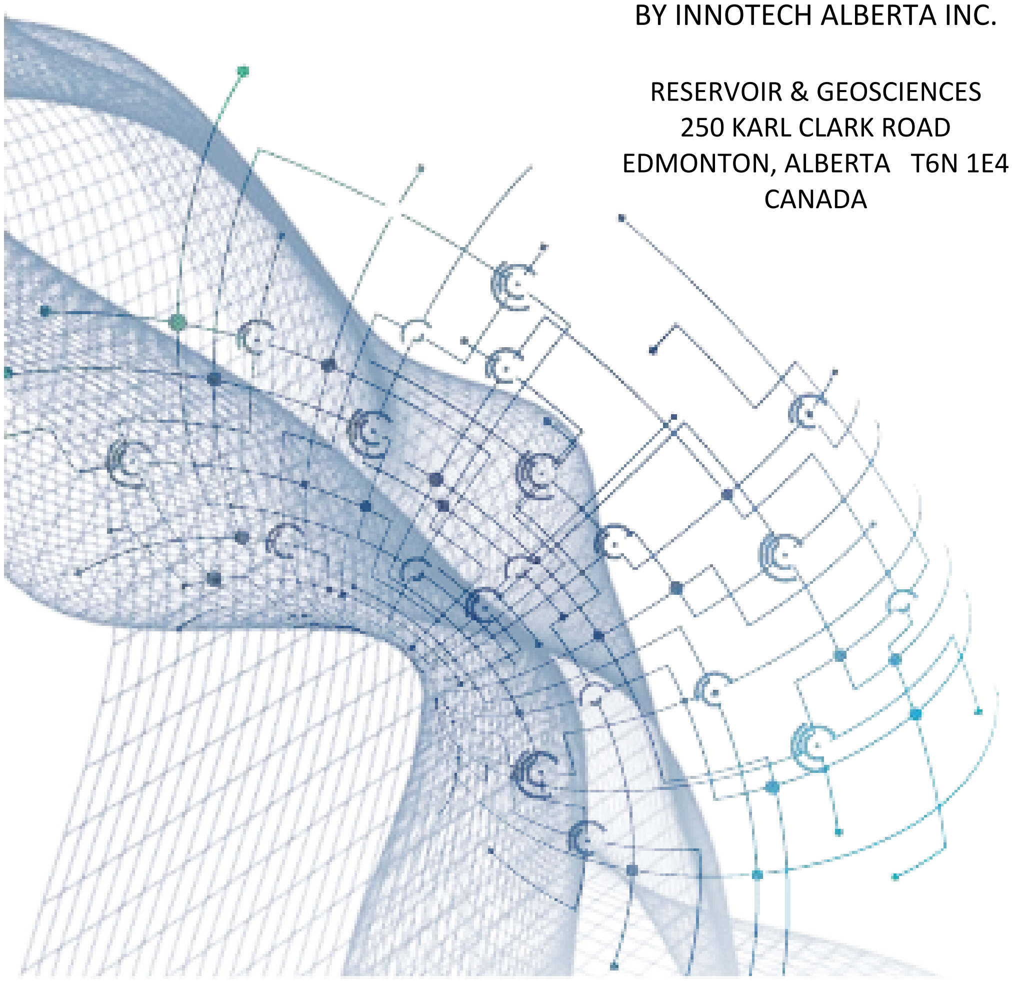

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EXECUTIVE SUMMARY

This project is part of a contract with Petroleum Technology Alliance Canada (PTAC). PTAC has engaged InnoTech to test three alternate products which are believed to have superior properties compared to oilwell cement for the purposes of certain well remediation applications and casing plugging. This report is for Phase 1 testing of a resin provided by Challenger Technical Services Ltd. (Challenger). The resin is in development and has not undergone field trials. Challenger intends to use this resin for well remediation in applications behind well casing.

The objective of using a resin in well remediation and abandonment procedures is to reduce costs and to safely improve outcomes while providing permanent barriers for hydraulic isolation in wellbores. With specific applications of this resin, the inventory of leaking wells and inactive wells is expected to be reduced.

An overall testing and assessment procedure developed by InnoTech, in communication with the AER, is designed to support successful field trials with minimal risk of adverse effects or failure over the life of the well, including post decommissioning / abandonment. Acquiring regulatory acceptance for wellbore applications of the resin is critical to achieve the stated purposes of the resin.

A toxicology assessment, a risk assessment and a mitigation strategy based on existing Safety Data Sheets (SDS) was completed including potential risks to ground water. The resin was found to be low to medium risk overall provided all appropriate practices are applied. The recommended mitigation procedures are included in this report and are intended for inclusion into the Challenger standard operating procedures (SOP).

The shrinkage of the resin was calculated at 2.87 % when the resin was curing under 7 MPa pressure in 114.3 mm OD casing. No radial shrinkage was observed on the circumference of small quantities of resin set in 200 ml glass containers or in the 13.6 mm annulus of a dry steel casing stub with an aluminum cylinder placed as a central spacer.

Radial shrinkage was observed when the resin was cured in an empty and dry 114.3 mm OD casing stub. The resin in this casing stub axially expanded out the top of the casing stub when curing at room temperature and pressure. Radial shrinkage was also observed in the table-top resin samples cured in large glass containers and there was evidence of voids in the resin. When placed and cured under pressure in a wellbore, any gas filled voids are expected to be significantly smaller due to gas compression.

Adhesion–shear testing was conducted on resin plugs set in a short pieces of steel casing by using a precision press with a recording instrument. The force required to break the adhesion of a resin sample set inside a casing stub was divided by the inside surface area of the casing stub. Two samples with an internal aluminum centralizer core were tested and two samples with only resin in the casing stub were tested. The lowest shear adhesion was 11.1 MPa for a sample with the centralizer and 0.82 MPa for a resin sample with no centralizer.

Resin was placed in 114.3 mm OD (84.3 mm ID) water wet steel casing and seven 76 mm OD cementing wiper plugs were pushed into the resin. The wiper plugs were intended to be tested as central spacers in the casing. and the plugs totaled 86 cm in length. The casing contained resin above and below the spacers. The casing was pressured to 7 MPa using water and the resin allowed to cure.

After the resin was fully cured in the casing, a differential pressure test was conducted at 7 MPa for 7 days. Water was used as a pressure medium and precision instrumentation recorded the pressure, the pump rate and time. After the resin was cured, an average stabilized leak rate of 1 ml/ hr (0.024 liters per day) was measured. This leak rate would not be detectable in a wellbore pressure test.

Endurance testing of the resin was conducted using a procedure simulating a highly corrosive reservoir condition where an extraordinary rate of uncemented casing failures is known to occur in wellbores. After 194 days of endurance testing, it was evident that the resin degrades less significantly than the class G cement sample and the J55 steel sample. During the endurance testing, the cement sample properties changed over time and the steel sample exhibited a slow and consistent mass loss. This resin did not show any signs of adverse effects and gained 0.6% of its original mass.

The resin was set in motor oil, in water, in canola oil and in a paraffin lined container. No negative effects were observed while the resin was curing in motor oil. Some foaming was observed when the resin was set in water. The resin did not fully cure when it was set in canola oil. The resin is exothermic when setting but the volume and maximum temperature of the sample was not hot enough to fully melt the paraffin lining the glass container. There was visual evidence of a few spots where the paraffin melted. This information may be used when planning further testing on the resin.

It was determined that the resin can be used safely and is not a material risk to ground water when deployed outside of casing, provided all appropriate mitigation procedures are followed.

The resin provided a seal when cured in a short dry casing stub with an aluminum cylinder placed in the middle, but a very low leak rate occurred when the resin was cured in water wet casing with wiper plugs placed as central spacers. Further testing is recommended to investigate these differences and Challenger has work underway to assess this very low leak rate.

The resin appears to be suitable for sealing smaller flow pathways such as annular areas between casing strings or between casing and formation. It is also likely effective for sealing fractures, channels, and worm holes in pre-existing wellbore cement. Further testing that is specific to these conditions is recommended.

The test results indicate that the cured resin has superior properties to oilwell cement in specific applications as a wellbore sealing material.

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1.0 INTRODUCTION

This report is for the testing of one alternate product, a resin from Challenger Technical Services Ltd.

Approximately 460,000 wells have been drilled in Alberta since the 1880s. Technology, best practices, and regulations related to well integrity have changed immensely over the last 130 years. Alberta has roughly 40,000 wells that are leaking to surface and about seven percent of the new wells drilled in Alberta leak to surface from the time they are drilled. Thousands of legacy wells which are not leaking to surface are believed to require hydraulic isolation between formations due to inadequate primary cementing.

Well integrity is a world-wide concern and methane from leaking wells is understood to be a source of greenhouse gas emissions (GHGs). Many jurisdictions have public policy to reduce GHGs. Canadian targets for emissions reduction are stringent. Under the Paris agreement, Canada committed to reducing GHGs by 30% from 2005 levels by the year 2030. The federal government announced an objective to achieve net zero emissions by 2050. The protection of ground water is also a significant concern among regulators and the public.

There is an urgent need to address a massive inventory of over 90,000 inactive wells in Alberta. There are also about 100,000 marginal wells in Alberta that will become inactive in a few years. Many inactive wells have surface casing vent flow (SCVF) and or gas migration (GM). Industry needs reliable and cost-effective means of remediating leaking wells. Most Alberta wells with SCVF/GM leak at very low rates which are the most difficult to repair with traditional cementing practices. These traditional methods have a high failure rate as typically three separate attempts are required to be successful. Roughly 16 % of wells that are repaired with cement and then abandoned end up leaking again after the site has been reclaimed (Boyer, AER presentation at CSGM GeoConference, March 2016).

Bail dumping cement as an abandonment plug on top of bridge plugs has serious shortcomings. The sealing elastomers in bridge plugs are known to have a limited lifespan. A PTAC study (PTAC Downhole Well Abandonment Project Objective 1 & 2 Report) further demonstrated the complete ineffectiveness of bail dumped cement as a permanent wellbore plug. https://www.ptac.org/wp-content/uploads/2016/08/Final-Report-5.pdf

Developing low-cost solutions with much improved outcomes is critical. There are potentially billions of dollars in cost saving when enhanced solutions are developed and implemented. Industry is developing advanced alternate products to replace traditional cement in specific applications. Well remediation of leaking wells on land typically costs about $150,000 per well using conventional cement repairs (circa 2020). Some repairs cost much more.

InnoTech estimates that $3 billion could be saved in Alberta on leaking well interventions with the use of alternate products if the average number of interventions was reduced from three attempts to 1.5 attempts to achieve success. This improvement target is based on verbal reports from one major Canadian oil and gas company and is attributed to actual field applications.

The AER does not have rules or directives regarding the application of alternate products in place of cement and they apparently do not have the resources to determine when products are safe or effective. InnoTech established a precedent, as an independent technical authority, with the AER for testing/assessment of one alternate product so that the AER could accept the use of that product in field trials.

InnoTech is maintaining communication with the AER with respect to ongoing testing of other alternate products. It is important that the AER is fully informed of the technical advantages or disadvantages of alternate products and how any risks are mitigated so that the regulator can accept the use of these products in field trails.

This program, 20-WARI-01 Phase 1 testing, is designed to provide independent evaluations of three alternate products and to determine their suitability to go to Phase 2 testing. Phase 2 testing will simulate additional and common wellbore conditions for the application of alternate products in field trials. The field pilots proposed for wells are classed as Phase 3 testing.

2.0 OBJECTIVES

The objectives were to assess the toxicological risks of the resin along with developing any required mitigation, to assess some of the physical properties of the resin and to test the resin as a wellbore sealant. Also, to assess the endurance or life expectancy of the resin relative to other wellbore materials.

2.1 ASSESS TOXICOLOGICAL RISKS

A key objective is to conduct a toxicology assessment on the resin components based on the Safety Data Sheets (SDS) and to identify any potential hazards during handling, storage, transportation, field wellbore applications and disposal of unused product.

Another objective is to develop risk assessments for applying the resin. This includes if a surface spill occurs, the possibility of contacting ground water and to consider potential risks when the resin is in the presence of ground water. A mitigation strategy must be developed to address any identified risks.

Recommendations were made to supplement the vendor's Standard Operating Procedure (SOP) to ensure that appropriate safety measures, quality control and operating guidelines are included. This includes a sign-off sheet for the vendor and the well operator to verify that the SOP is followed during field applications. The signed sheet should be retained for audit and regulatory purposes.

2.2 SHRINKAGE / EXPANSION TEST

The shrinkage / expansion testing objective is to measure the change in volume of the resin as it cured in steel casing under simulated wellbore conditions. The resin is set in water wet 114.3 mm steel casing to form a plug along with wiper plugs used as centralizers. The resin is then cured under pressure. The change in water cap volume is used as an indicator of shrinkage or expansion. A product with minimal or no shrinkage is desirable for sealing a wellbore. If any shrinkage occurs, an assessment of annular or radial shrinkage is also needed.

2.3 ADHESION – SHEAR TESTS

The adhesion–shear testing objective is to determine the force required to initially move a cured resin plug inside a casing stub and then the force required to continue moving the plug. In this instance a dry casing stub containing only resin and a casing stub with a solid metal cylinder placed in the center of the casing stub were used. The adhesion to steel tubulars and resistance to movement is an important consideration in wellbores for maintaining hydraulic isolation.

2.4 PRESSURE TEST IN CASING

One of the important objectives of this program is to conduct a differential pressure test on the product when set as a plug inside casing under simulated wellbore conditions. Sealing at a minimum differential pressure of 7 MPa across plug for 24 hours is considered a pass for a plug set in casing. It is important to understand the differential pressure limits of a product plug when in service in a wellbore.

Another objective was to assess the effectiveness of a resin wellbore casing plug when cementing wiper plugs are placed in the casing and submerged in the resin.

2.5 ENDURANCE TESTING

The endurance testing objective is to determine if the resin will last as long, or longer, than other customary wellbore materials, namely steel casing, and class G oilwell cement. An accelerated procedure was developed which simulates a very corrosive wellbore environment in Alberta. Common J55 steel casing has demonstrated a linear corrosion rate in this environment. A product that is superior to oilwell cement and steel casing in a wellbore is exceptionally valuable.

2.6 SETTING IN VARYING CONDITIONS

The objective is to observe the resin curing under limited conditions for applications in many Alberta wellbores. When a product is set in motor oil, canola oil and in a paraffin lined container data may be acquired to help design further laboratory tests simulating wellbore conditions.

Another objective is to assess the gel strength and working time of a table-top sample of the resin as it cures. This relationship is important to assess the time that a field technician will have to apply the resin in a wellbore after it is mixed.

3.0 EXPERIMENTAL & ASSESSMENT

In order to meet the stated objectives, a series of assessments and laboratory tests were conducted.

3.1 TOXICOLOGICAL RISKS

Safety data sheets (SDS) were provided by Challenger for all of the compounds used in mixing the resin. A qualified InnoTech scientist examined the SDS and conducted a toxicology assessment which is summarized in the RESULTS AND DISCUSSION section of this report. The SDS for all compounds in the resin blends are based on the Globally Harmonized System and are sometimes referred to as the MDS or SDS or MSDS or PSDS. The SDS are available on request. A full toxicology assessment covering the components in the resin blends is included in APPENDIX A.

The resin components and mixing rations that were used in InnoTech's assessments and laboratory work are listed in Table 1 below.

Table 1: Resin Liquid Components

Measurements for a final volume of:			**1**	**liter**	
Material	Form	sg	% by weight	Volume (ml)	Weight (g)
Resin (Part A)	liquid	1.104	72.8%	0.701	773.35
Hardener (Part B)	liquid	0.971	27.2%	0.299	289.74
BLENDED	**liquid**	**1.063**	**100.0%**	**1.000**	**1063.1**

Risk heat maps are included in APPENDIX B – Risk Assessment. This assessment was conducted considering the deployment of the resin as a remediation sealing product behind casing in wells based on the following three scenarios:

1. Risks if liquid resin is spilled on surface soil.
2. Possibility of the liquid resin contacting ground water.
3. Risk of the resin causing an adverse effect if any of the liquid resin does contact ground water.

After assessing the risks of storing, mixing, deploying, and disposing the resin, recommendations are made for supplementing the Challenger standard operating procedure (SOP) to mitigate the risks. This is included in APPENDIX C.

3.2 SHRINKAGE / EXPANSION

Preparation of the 114.3 mm casing for a pressure test across the resin plug is described in the PRESSURE TEST section below. After a total of 8.77 liters of liquid resin was poured into the casing along with the wiper plug spacers, the casing was pressure up with water to 7 MPa using a Quizix pump / data recording equipment. Several samples of the resin were kept for observation in glass jars of varying sizes and in vials. The vials were used for gel strength observation using InnoTech's Gel Strength code shown on Table 3.

As the liquid resin cured to a solid, the outside temperature of the casing vessel was recorded, the pressure was held at 7 MPa for 7 days as the resin cured. Water intake to the vessel was measured to maintain this pressure.

The resin shrinkage during curing was determined from the volume of the liquid resin and the final volume of the cured resin in the casing. The volume difference was calculated from the change in water volume of the headspace while the resin was curing. The water volume was corrected for pump slippage.

Observations of the samples set in glass containers and in casing stubs were made to visually assess if radial shrinkage occurred to create a micro annulus between the cured resin and the inside surface of the containers.

3.3 ADHESION – SHEAR

Short sections of 114.3 mm steel casing (82.6 mm ID) were cut, loose rust and mill scale were wire brushed from the inside of the casing stubs and one end of each stub was taped closed. Liquid resin was poured into one dry empty casing stub and into one dry casing stub containing a solid 57.2 mm OD aluminum cylinder placed in the middle. After curing, each casing stub was cut into two pieces of approximately 10 cm and 15 cm in length with flat surfaces to contact the pressure plate used in the adhesion-shear testing. The resin had fully cured at room temperature in the casing stubs when the adhesion-shear test was conducted.

An Intron Satec 600 DX load frame with 600 kN (135,000 lb) force capability was used to determine the force required to break the adhesion of the resin to the inside surface area of the casing stub as well as the force required to continue moving the resin plug after the adhesion was broken.

The adhesion - shear strength for the resin samples was determined by following the procedure below for the casing stub with the resin sample:

- Measure the length of the resin plug and the inside diameter of the casing stub. Calculate the surface area that the resin plug is contacting the inside of the casing stub.
- Position the casing stub so that a uniform pressure can be applied to one end of the plug with the other end left open so that any plug movement is not impeded by anything other than the adhesion to the inside of the steel casing stub.
- Slowly increase and record the force applied to the plug, noting the force when any fractures occur and when the first plug movement is observed.
- Record the force required to move the plug after the initial adhesion is broken.
- Calculate the shear - adhesion strength for the sample. The units will be the force divided by the inside surface area of the casing stub.

3.4 PRESSURE TEST

Casing chambers were constructed from new 114.3 mm OD, K55 steel casing with 12.7 mm wall thickness (84.28 mm ID) to conduct differential pressure testing on wellbore plugging products. The casing ends were machined and fitted with high pressure quick connection caps at each end. Each end cap assembly has an O ring seal, and the top cap is tapped for a 12.7 mm fitting. Figures 1 and 3 are images casing chambers and the end connections.

Prior to conducting the pressure test on the resin plug, the casing had internal rust and debris removed with a circular wire brush using a power drill and extension connection. To prevent the resin from bonding to the bottom cap, the bottom insert was heavily coated with paraffin.

An initial pressure test was conducted in the casing chamber filled with water to ensure there were no leaks in the pressure system and to measure any 'pump slippage' required to maintain pressure from the same Quizix pump.

After siphoning the water out, 6.54 liters of the resin was slowly poured from the top into the casing. Then seven wiper plugs were individually pushed in nose first and tapped into the casing until there was evidence of resin and residual water above the spacers. Approximately 4.49 liters (84 cm length) of resin was left below the spacers. The volume displacement of an individual wiper plug was measured at 0.4 liters and the total volume of all seven is a little under 2.8 liters when they are stacked and compressed onto each other. Another 2.23 liters of resin was added to the casing for a total of 8.77 liters of resin.

Air bubbles were allowed to propagate out of the mixture, the vessel was filled with water, the top cap installed, and the casing was pressured up with water to 7 MPa using the Quizix pump.

The temperature profile was continuously measured on the outside of the casing and 7 MPa was held on the casing for 7 days with the Quizix pump. Then with the resin cured, the casing vessel was de-pressured and the bottom and top ends were opened up for examination.

The pressure test was conducted across the casing plug using precision measurements and water as a pressure medium. The steps were as follows:

1. A drip tray was placed under the open bottom end of the casing section and observed for leaks during the pressure testing. The bottom connection was left open.
2. The top connections were made up on the casing to commence the pressure test across the resin plug in casing using the Quizix pump and water.
3. With the top side of the casing and system free of air, the pressure was increased in increments of 1 MPa and held at each pressure increase for 15 minutes or until the pressure stabilized. The pressure was increased to 7 MPa and held for monitoring.
4. When a leak occurred, identified by drops of water appearing in the drip tray, the pump rate was recorded. The initial leak rate was very low, so the pressure was increased in the planned stages.

After the pressure testing was completed, a probe was placed into the casing top, and the water cap length was measured to be 37.5 cm in length.

3.5 ENDURANCE TEST

Endurance testing was structured to assess any deterioration or changes in the resin relative to class G cement and J55 steel (wellbore materials) under accelerated field conditions while using a practical and repeatable procedure.

A sample of class G oilfield cement was previously mixed and set under ideal conditions for comparison in the endurance test. A sample of resin was prepared for this test. A piece of J55 steel tubing was also cut and surface debris removed for the endurance testing.

All samples were carefully weighed and placed in non-reactive plastic containers that had perforations to allow brine movement in and out of the containers.

A corrosive brine was blended based on water analysis from a Devonian – Wabamun formation in northern Alberta which is known to cause excessive well casing failures. Eleven well casing failures have been reported in T089 R003 W5. This formation water is sour, but InnoTech did not simulate H_2S in the test brines. Water analysis from two wells, 100/13-19-080-23W5/04 and 100/12-20-079-23W5/00 were used to prepare a simulated brine.

The composition of the simulated brine is shown below in Table 2.

Table 2: Chemical Composition Of Brine Used For Endurance Testing

Simulated Corrosive Brine	pH	Sodium mg/l	Potassium mg/l	Calcium mg/l	Magnesium mg/l	Iron mg/l	Chloride mg/l	Sulfate mg/l
Two analyses	1.5	56377	1206	15314	2888	93.5	130154	736

Figure 17 is a photograph of the endurance testing machine with pressure and temperature-controlled cylinders. The pressure cylinders are lined with a non-reactive material.

The brine and samples prepared for endurance testing were placed in a pressure cylinder at a temperature of 48 to 50 °C and a pressure of 4.1 to 5 MPa. During testing, the brine was kept in motion with the machine and the brine was replaced periodically to refresh the design composition. Figure 20 is an image of the samples after 194 days of endurance testing.

3.6 SET IN VARYING CONDITIONS

Samples of resin were set in glass containers with different contents. One container held motor oil, another held canola oil, one container was lined with paraffin canning wax on the inside surface of the glass container, other containers were dry, and others held tap water.

The samples were observed to see if the contents of the containers affected the setting of the resin at room conditions and to determine if the paraffin wax melted in the glass container.

InnoTech has developed a gel strength code to observe and describe how the gel strength of a material is changing as it reacts or sets, as shown in Table 3 below. The resin was evaluated by placing small samples of liquid resin into vials and using this coding system as the resin was setting in its early stages. Since the resin is highly exothermic when setting, a larger volume will set faster due to the elevated temperature of the resin.

Table 3: InnoTech Gel Strength Code

Class	Description	Letter Grade	Number Grade
No detectable gel formed	The gel appears to have the same viscosity-(fluidity) as the original solution and no gel is visually detectable	A	0
Highly flowing gel	The gel appears to be only slightly more viscous (less fluid) than the initial solution	B	1
Flowing gel	Most of the obviously detectable gel flows to the bottle cap upon inversion	C	2
Moderately flowing gel	Only a small portion (about 5 to 15%) of the gel does not readily flow to the bottle cap upon inversion - usually characterized as a "tonguing" gel (i.e., after hanging out of jar, gel can be made to flow back into bottle by slowly turning bottle upright)	D	3
Barely flowing gel:	The gel can barely flow to the bottle cap and/or a significant portion (>15%) of the gel does not flow upon inversion	E	4
Highly deformable non flowing gel	The gel does not flow to the bottle cap upon inversion (slowly flows)	F	5
Moderately deformable nonflowing gel	The gel flows about halfway down the bottle upon inversion	G	6
Slightly deformable nonflowing gel	The gel surface only slightly deforms upon inversion	H	7
Rigid gel	There is no gel surface deformation upon inversion	I	8
Ringing rigid gel:	a tuning-fork-like mechanical vibration can be felt after tapping the bottle	J	9
Rigid gel < 5% liquid	Minimal free liquid (< 5%)	K	10
Rigid gel > 5% liquid	Free liquid (> 5%)	L	11

4.0 RESULTS & DISCUSSION

4.1 TOXICOLOGY

The toxicity assessment of the preset components of the resin are outlined in APPENDIX A. The components could be fatal to humans and wildlife if ingested or inhaled and caution should be also taken to avoid skin and respiratory irritation.

Three risk assessments were conducted for the following conditions and are included in APPENDIX B:
1. Risks if a surface spill of the resin does occur
2. Possibility of liquid resin contacting ground water during as well operation
3. Risks if liquid resin does contact ground water in a wellbore

All of the subject risks can be mitigated with appropriate technical and operating controls. This is to ensure that the resin is mixed, applied and handled in accordance with accepted practices.

Recommendations for the Challenger standard operating procedure (SOP) are included in APPENDIX C to address additional mitigation procedures identified in the risk assessments, to ensure good practices when using the resin and to utilize a vendor – producer sign off sheet for audit purposes.

4.2 SHRINKAGE / EXPANSION

The volume of liquid resin that was added to the casing was measured at 8.77 liters and 0.252 liters of water was added to the casing as the resin cured under 7 MPa pressure. Weight measurements were used to measure the resin due to the viscosity and the residual resin remaining in handling containers. Using these volumes, a shrinkage of 2.87 % was calculated.

No radial shrinkage was observed on the circumference of small resin samples set in 200 ml glass containers or in the 13.6 mm annulus of a dry 84.4 mm ID steel casing stub with an 57.2 mm OD aluminum cylinder placed as a central spacer. Figures 12 and 13 are images of the casing stubs. Figures 9 and 10 are images of resin cured in glass containers.

Some radial shrinkage was observed in dry 114.3 mm OD casing without any insert spacer material. Radial shrinkage was also observed in the larger table-top samples held in large glass containers.

Gas filled voids appeared in the larger volume table-top samples but not in smaller volumes. Figure 9 is an image of two glass containers, 200 ml in size, containing different volumes of resin that is cured. The larger volume of resin contains visible voids in the resin and the smaller amount of resin does not.

Figures 12 and 13 indicate visible voids in the resin that was cured in a casing stub with no centralizer.

When applied in a wellbore, the treatment pressure and the hydrostatic pressure in the well is expected to significantly compress any gas expansion that was observed in the larger resin samples at room conditions. This is evident from the shrinkage that was calculated in the casing when the resin was curing under 7 MPa pressure verses the resin curing in the casing stub at room conditions where the resin apparently developed gas voids and expanded/extruded out the top of the casing stub.

4.3 ADHESION – SHEAR

Two scenarios were assessed using dry casing stubs. One was with no insert centralized in the casing and the second was with a solid cylinder centralizer in the casing stub. In each scenario, a short and a long casing stub was tested.

The forces were measured to cause initial movement of the resin plugs and to break the adhesion between the resin plugs and the steel casing stubs. Then the force to move the plugs was measured after the initial adhesion was broken. The test results are indicated in Table 4.

Table 4: Shear Adhesion Test Results Resin In Casing Stubs

Challenger Resin Samples	Length (mm)	Shear Adhesion (MPa)	Push Out (MPa)	Observations
No centralizer, long sample	151.4	0.84	0.12	No unset regions in plug or sticky areas Sample had voids in the resin & some radial shrinkage Initial crack, then a louder sound when adhesion broke Fit easily back into casing stub after being pushed out
No centralizer, short sample	96.8	0.82	0.14	No unset regions in plug or sticky areas Sample had voids in the resin & some radial shrinkage Fit easily back into casing stub after being pushed out
With centralizer, long sample	153	>14.91	N/A	No unset regions in plug or sticky areas Some surface cracks, but specimen intact inside, appears centralizer eliminates radial shrinkage Machine reached 600 kN force capacity limit without moving plug Centralizer moved ~2 mm within resin - surrounding resin flexed
With centralizer, short sample	100.5	11.1	~10.1	No unset regions in plug no sticky areas Sample largely free of voids, minor cracks on the surface where pressure plate was applied Shear bond broke with loud bang Pushed out resin/core and it would not fit back inside casing stub After initial release, required significant but variable force to continue moving

As indicated in Table 4, the resin samples with an aluminum cylinder placed as a centralizer in the middle of the steel casing had more than thirteen times more adhesive strength than the samples with resin only. The lowest force recorded to break the adhesion in samples with the solid centralizer was 11.1 MPa and 0.82 MPa in a sample with resin only.

The samples with resin and the solid centralizer did not have voids or radial shrinkage. When one sample with a centralizer was pushed out of the casing stub it appeared to have expanded slightly and would not fit back into the casing stub.

The samples with only resin in the casing stubs developed voids in the resin when curing and a partial loss of adhesion to the inside of the casing stub. As discussed in Section 4.6, the voids are believed to be related to a higher exothermic reaction when a larger volume of the resin is curing.

4.4 PRESSURE TEST

The bottom insert plug was difficult to remove and it was evident that the resin had adhered to the top of the insert. The top of the insert was partially water wet and sticky in other places. It appeared that most of the paraffin coating had melted.

When pressured up to 1 MPa on the top side of the casing, water drops appeared, and the leak rate was roughly 2.9 ml/hr. When the casing was pressured up in 1 MPa stages from 1 MPa to 7 MPa, the leak rate was consistent at each pressure at roughly 3.4 ml/hr.

The pressure was held at 7 MPa for 7 days and the leak rate was stable and ranging between 0.76 to 1.32 ml/hr. Then the leak rate increased a little and stabilized between 1.25 to 1.32 ml/hr before the test was terminated. Overall, the average leak rate was 1 ml/hr.

The leak rate as was measured would not be detected on a field wellbore pressure test.

4.5 ENDURANCE TEST

The steel, cement and resin samples underwent endurance testing for 194 days. The results are shown in Table 5 below. Figure 18 is a photograph of the samples before endurance testing and Figure 19 is photo of the samples after 90 days of endurance testing and Figure 20 is a photo of the samples at the end of the test.

Table 5: Endurance Testing Initial Weights Of Samples And % Change

Sample	Initial Weight Grams	Days Tested	After 194 Days Testing - Sample % of Original Weight	Measurement Conditions
J55 Steel	223.84	194	98.6%	Towel dried
Class G cement	396.66	194	111.7%	Oven dried
Resin	218.21	194	100.6 %	Oven dried

As the endurance testing progressed the steel sample decreased mass uniformly. Figure 21 indicates the percent weight changes of the samples over 194 days of endurance testing.

The cement sample initially gained weight, then leveled off and then gained weight again as the sample started to break apart. The gain in mass is likely due to brine retention in the cement porosity and possibly due to other chemical reactions in the cement. The cement sample appeared to undergo some chemical changes and displayed significant deterioration near the end of the test period.

The resin sample gained about 0.6% weight overall and the increase in mass was fairly uniform over the endurance test. The resin did not appear to deteriorate.

The cement sample and the containers are stained a brown color from corrosion of the steel sample in the brine. Part of the appearance change in the cement throughout this test likely due to chemical reactions in the cement.

4.6 SET IN VARYING CONDITIONS

The resin did not show any visible or adverse effects when set in the containers holding motor oil or the container that was lined with wax.

There was some foaming on top of the resin when the resin was set in water.

The resin did not fully cure when placed in canola oil. The contact surface between the resin and the canola oil remained in a gelled condition and would visibly move when the container was agitated.

The results of the resin gel strength assessment while curing a small sample at room temperature and using the InnoTech Gel Strength coding, are shown below in Table 6 and Figure 8.

Table 6: Resin Gel Characteristics While Curing

Hours From Mixing	Number Grade	Letter Grade	Classification	Description
0	0	A	No detectable gel formed	The gel appears to have the same viscosity-(fluidity) as the original solution and no gel is visually detectable
0.17	0	A	No detectable gel formed	The gel appears to have the same viscosity-(fluidity) as the original solution and no gel is visually detectable
0.67	1	B	Highly flowing gel	The gel appears to be only slightly more viscous (less fluid) than the initial solution
1.67	2	C	Flowing gel	Most of the obviously detectable gel flows to the bottle cap upon inversion
2.67	3	D	Moderately flowing gel	Only a small portion (about 5 to 15%) of the gel does not readily flow to the bottle cap upon inversion - usually characterized as a "tonguing" gel (i.e., after hanging out of jar, gel can be made to flow back into bottle by slowly turning bottle upright)
3.67	3	D	Moderately flowing gel	Only a small portion (about 5 to 15%) of the gel does not readily flow to the bottle cap upon inversion - usually characterized as a "tonguing" gel (i.e., after hanging out of jar, gel can be made to flow back into bottle by slowly turning bottle upright)
4.67	7	H	Slightly deformable nonflowing gel	The gel surface only slightly deforms upon inversion
25.67	8	I	Rigid gel	There is no gel surface deformation upon inversion

5.0 CONCLUSIONS

5.1 TOXICOLOGY

Based on the toxicology assessment, the resin is safe to use as a wellbore sealing product provided that enclosed recommendations are followed in the Challenger SOP. After the resin has cured there are no known risks.

5.2 SHRINKAGE / EXPANSION

Radial shrinkage did not occur when the resin was placed in small cylindrical jars or in the annular space of the casing stubs. However radial shrinkage was observed in larger cylindrical jars and in a casing stub without a centralizer. There is specific size, shape or volume of liquid resin placement in a cylinder where the resin will apparently revert from having no radial shrinkage to having radial shrinkage occur.

The observed foaming and the voids that occurred in larger resin samples may provide insight when developing further testing to quantify the conditions where radial shrinkage will occur when the resin is cured in a cylinder.

When cement sets and shrinks, it is known to create a micro annulus between the cement and casing. The Challenger resin appears superior to cement when used as an annular sealing barrier in a wellbore based on the results of the shrinkage observations and the shear-adhesion tests

5.3 ADHESION – SHEAR

Resin samples with a centralizer in the middle of the steel casing and with no voids in the resin had more than thirteen times more adhesive strength than the samples with resin only. The 100.5 mm long casing stub with a centralizer had an adhesive strength of 10.1 MPa. This ultra-high strength is exceptionally valuable when only a short length of resin can be placed in an annular area behind casing to seal a leak pathway.

A sample without voids in the resin appeared to have expanded slightly and would not fit back into the casing stub.

It may be possible to prevent voids from developing as the resin is curing by controlled the peak exothermic reaction or by other chemical means. Some considerations to achieve this may be slowing down the curing time and controlling the volume and shape of the resin while curing. Further study and testing are recommended in this regard.

5.4 PRESSURE TEST

The casing pressure test with resin and wiper plugs as a barrier in full diameter water wet casing was not successful in creating a complete seal under the conditions that were utilized. Further testing is recommended to assess why this very low leak rate occurred. One consideration is the potential compressibility of the wiper plugs when placed in the casing.

Another consideration is the impact of residual water on the casing surface that could not be removed in this test procedure. In field applications practical steps should be taken to ensure the resin or a pre-flush fluid has displaced water off of the casing, cement and rock surfaces where sealing is desired.

5.5 ENDURANCE TEST

The resin is expected to last longer than Class G oilfield cement and steel casing in wellbore conditions. The J-55 steel corroded at a continuous rate and the cement sample exhibited substantial deterioration. There were no adverse effects observed on the resin.

5.6 SET IN VARYING CONDITIONS

The resin is not expected to have any adverse reaction when setting in the presence of hydrocarbons.

In field operations it is good practice to ensure there is sufficient volume between the resin and a liquid hydrocarbon to minimize mixing / dilution of resin in the area where the resin is designed to cure and seal.

Foaming of the resin in wellbore conditions may be controlled by a defoaming agent. It is important to ensure that the defoamer is designed for the specific application, considering the wellbore fluids, the volume and geometry of the resin when placed and the expected exothermic reaction.

6.0 RECOMMENDATIONS

If the liquid resin has the potential to contact ground water, certain precautions must be taken to mitigate risks as follows:

1. Ensure that the planned operation will not permit the resin from migrating in ground water outside of the wellsite lease area, approximately 20 m from the wellbore.
2. Pre-test the resin blend in advance of the operation to ensure that the resin cures as planned.
3. Follow the Challenger SOP with the enclosed supplemental recommendations.

The observed shrinkage characteristics and the generation of voids in the resin of the resin may be related to the geometry and the volume of the resin when setting and the associated exothermic reaction when the resin is setting. Additional studies are recommended to determine the optimal volume, geometry, exothermic reaction and setting time to mitigate shrinkage and adverse effects when curing in a cylinder or and annular space.

More study is required to assess why the resin did not fully cure when in the presence of canola oil

As the resin is considered for future wellbore applications it is recommended to assess the reaction of the resin in other chemicals and fluids that may be present in a wellbore, and which may interact with the setting of the resin.

Challenger's objective is to use the resin as a sealant in small pathways behind casing and as a plug inside of casing. Further analysis is recommended to confirm how successful sealing can be consistently achieved in an open casing by eliminating the voids that developed in some large table-top samples and in casing stubs. Challenger is considering shop testing several concepts to address this issue.

Achieving a successful seal to maintain or restore hydraulic isolation in a wellbore is dependent on the sealing material having very good contact with the surfaces of steel casing, cement or the rock formations. The presence of water and hydrocarbons in a wellbore during field applications should be mitigated to achieve the desired contact to the targeted surfaces.

The reason why a very low leak rate occurred in the water wet casing was possibly due to the lack of displacement of the water which was on the inside surface of the casing. It is recommended to take practical steps to displace wellbore fluids from the contact surfaces where the resin is planned to be placed as a sealant in wellbores. Several options may be considered such as using specifically designed pre-flush fluids before placing the liquid resin. Challenger is considering shop testing several concepts to address this issue.