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Heavy Oil

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Quest CCS Project

Quest IPM Compressor Design Modeling Results

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Summary

This report documents the SIEP modeling work that confirms a compressor with a 14.5 MPa discharge pressure is sufficient to provide the necessary wellhead and bottomhole pressures to inject the minimum 1.2 mtpa CO_2 required for the Quest CCS project under the conditions studied. This report also shows a 14.5 MPa compressor discharge pressure coupled with a 12 NPS pipeline is able to inject up to 3.4 mtpa CO_2 into five wells, pending the subsurface case realized.

Keywords

Quest, CCS, IPM, GAP, Compressor, Pipeline

Quest IPM
Compressor Design
Modeling Results
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SUMMARY

This report documents the SIEP modeling work that confirms a compressor with a 14.5 MPa discharge pressure is sufficient to provide the necessary wellhead and bottomhole pressures to inject the minimum 1.2 mtpa CO_2 required for the Quest CCS project under the conditions studied. This report also shows a 14.5 MPa compressor discharge pressure coupled with a 12 NPS pipeline is able to inject up to 3.4 mtpa CO_2 into five wells, pending the subsurface case realized.

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1. INTRODUCTION

1.1. Project Background

The Quest CCS Project proposes injection and subsurface storage of up to 1.2 mtpa of CO_2 from the Scotford Upgrader into the deep saline formation of the Basal Cambrian Sand (BCS) and also seeks to identify scope for growth to inject 2-12 mtpa in the license area. Two prior appraisal wells were drilled over the winter season of 2008-9 and have been evaluated.

The first two wells, Redwater 102/11-32-55-21, also referred to as Scotford, and Redwater 100/3-4-57-20, also referred to as Redwater, confirmed our understanding of sub-regional geologic reservoir continuity, pressures and fluid salinities and provided samples for further analytical work. The Scotford well partially confirms injectivity based on a water injection test that did not reach radial flow conditions. The Redwater well confirms an observed trend to encounter higher porosities and permeabilities moving northeastward from Scotford.

A third well, Radway 8-19-59-20W4, also referred to as Radway, is being drilled in August 2010, in order to collect geologic data sufficient to prove the viability of the area surrounding this well for commercial injection development, and to reduce reservoir uncertainty that will affect critical FDP design parameter decisions like number of injector wells and injection pressure requirements.

1.2. IPM Background

Petroleum Expert's Integrated Production Modeling (IPM) toolkit includes the following:

- PVTP - An advanced Pressure Volume and Temperature analysis software.
- MBAL - The industry standard for accurate Material Balance in modern reservoir engineering.
- Reveal – A numerical simulator that can integrate specialist reservoir studies.
- Prosper – The industry standard well modeling tool, with the ability to address each aspect of wellbore modeling, including fluid characterization, calculation of pressure loss, and reservoir inflow.
- GAP – A General Allocation Package that simulates multiphase flow in order to model and optimize production and injection networks, allowing the engineer to build complete system models, including the reservoirs, wells, and surface network.
- Resolve – A tool that allows dynamic coupling between different engineering packages, such as economic spreadsheets, reservoir and process simulators, and any of the aforementioned tools in the IPM suite.

Quest's integrated injection modeling system includes the integration of the well model with the surface network. GAP is directly linked to Prosper to model the injection system from the compressor to the top perforation. The GAP optimizer provides the ability to maximize the total CO_2 injection and, at the same time, to honor a CO_2 injection rate constraint at each well.

Though possible and recommended, it was agreed not to use Resolve to link the CMG reservoir simulators with GAP at this time due to the team's limited resources.

1.3. Compressor Design Background

A study was performed by SCAN and SIEP to determine the optimum compressor size to use for the Quest project, taking into account the lifecycle cost of increasing the compression, additional pipeline costs, effect on the discharge temperature, and the ability to provide adequate bottomhole pressure in the injection wells.

It was uncertain whether a 14.5 MPa or a 20 MPa compressor would be needed to provide the necessary pressure requirements. SCAN used Unisim (a process simulator) and SIEP used GAP to model this. Unisim lacks the capability of including a well model, and so must simulate the well as another pipeline. GAP, however, uses the well model to provide a more representative injectivity based on the well's reservoir inflow performance.

Both Unisim and GAP were used to model the pressure and temperature losses from the compressor to the wellhead, the results of which were in agreement with each other. GAP was then used to link the available wellhead pressures and temperatures with the reservoir to more accurately predict bottomhole injection pressures and temperatures.

The purpose of this report is to provide the GAP results of the compressor sensitivity study. The Unisim results and economic comparisons of the study can be found in a separate report completed by SIEP, Document# 07-1-AA-8212-001[1].

2. GAP NETWORK

Quest's GAP model was technically assured by Hon-Chung Lau (PT Discipline Lead) and Keshav Gorur (PT) on June 10, 2010. The applicable Note for File can be found in Appendix 1.

For each element in GAP, the PVT EOS compositional method with Peng-Robinson EOS and full volume shift have been used, as is recommended in the Production Technology CO_2 Guidelines[2].

The fluid composition used in each element includes H_20, CO, N2, H2, and C1 impurities as provided by Shell Canada (Appendix 2).

Quest's GAP model does not link a reservoir model to the well and surface model. All wells are therefore considered equal, with the same properties, injecting at constant rates.

An example diagram of Quest's GAP network can be found in Figure 2.1 below. The main components of the GAP network are described in detail in the following sections.

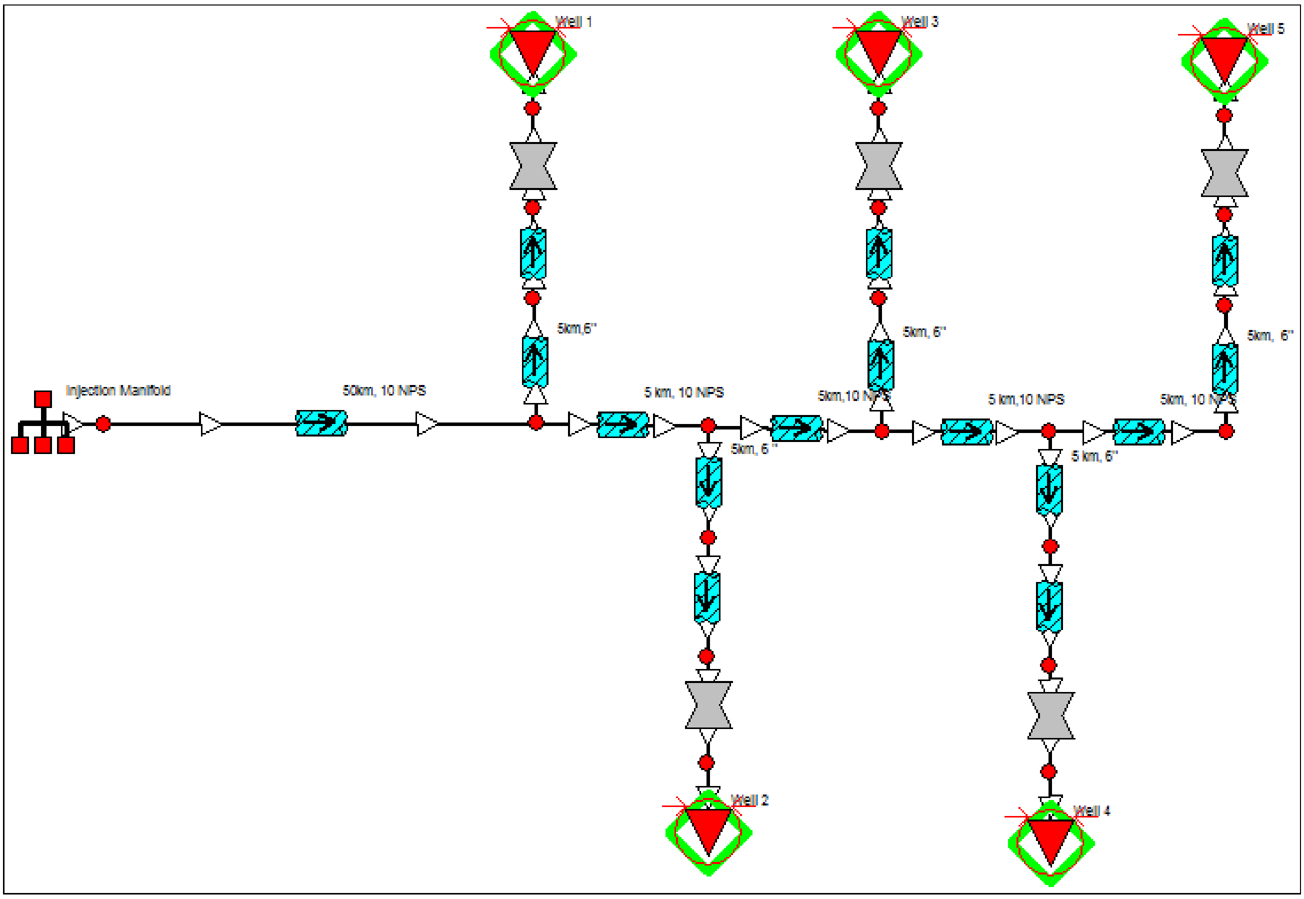

Figure 2.1 GAP Network Diagram

2.1. Injection Manifold

The compressor discharge pressure and temperature is input under the "Injection Manifold" icon.

2.2. Pipelines

Pipelines connect the compressor output to the individual wells. The pipeline dimensions and temperature of surroundings are input. Pipelines are assumed to be buried 1.2 m underground.

Though SRTCA is Shell's preferred surface equipment correlation, it is slow and in rare occasions gets stuck when solving. It was therefore recommended by the Integrated Production System Modeling Global Deployment Team (IPSM GDT) to use Mukerjee Brill, as even for multiphase flow its results have proven close enough to those using SRTCA for the whole range of simulations run.

Though enthalpy balance is the recommended model to use for effective temperature modeling, it has proven problematic in the current version of GAP (IPM 7.1 Build #150 Gap v8.1). The recommendation given by Petroleum Experts (PETEX) was to use the rough approximation model, where an overall heat transfer coefficient (OHTC) is entered, until the next version of GAP is released in which this issue has been corrected. The OHTC's used (2 – 6 $W/m^2/K$)[i] are in agreement with the values used for SCAN's Unisim modeling.

2.3. Wells

The same Prosper file is attached to each well icon. The fluid type is chosen as retrograde condensate in order to capture the phase changes effectively. The enthalpy balance temperature model is used for effective temperature modeling, in which the drilling and lithology data have been input.

Vertical wells with 4.5" tubing to 2,049 m are assumed. Deviated and horizontal well modeling will be addressed in a separate report.

The drilling and completion data were obtained from the February 2010 Proposed Well Schematic (Appendix 3).

Lithology input was summarized from the Petrophysical descriptions of the formation tops.

Petroleum Experts is chosen for the Reservoir Model in the Inflow Performance Relation (IPR). This is the Reservoir Model of choice for the retrograde condensate fluid since it uses the pseudo pressure method which takes into account changes in fluid properties for different pressures.

Reservoir Permeability is entered as gas permeability. Since Prosper is a static model, representing one snapshot in time, the changing relative permeabilities are not captured in this model. Instead, sensitivities are run on different gas permeabilities to reflect how they are expected to change with time.

A reservoir thickness of 38 m and a perforated interval of 30 m are assumed.

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[i] See SI Metric Conversion at end of report

3. COMPRESSOR SIZING

GAP was used to help decide between a 14.5 MPa and a 20 MPa compressor for the Quest project. Since the smallest compressor would be the most economical, the modelling strategy was to attempt to prove sufficient injection with a 14.5 MPa compressor, and only if this could not be proved, to then model this with a 20 MPa compressor as well.

The compressor design is limited by the maximum allowable bottomhole injection pressure (BHIP). Per Directive 51 of the Energy Resources Conservation Board (ERCB), which regulates the energy industry in Alberta, Canada, CO_2 injection pressures will be limited to 90% of the formation fracture pressure[3]. Based on the results from the first appraisal well (Appendix 4), 28.35 MPa is 90% of the BCS minifrac closure pressure, and 33.3 MPa is 90% of the LMS microfrac extension pressure. It is anticipated that the ERCB will define fracture pressure as the extension pressure; however, 28.35 MPa (being the most conservative value) is currently considered the maximum allowable bottomhole injection pressure.

3.1. Surface Scenarios

The available wellhead pressures are dependent on the amount of pressure loss experienced across the pipelines. The main factors that influence this are compressor discharge pressure, pipeline size, and well spacing.

A four and five well count scenario is compared against a 10, 12, and 16 NPS pipeline. A seven well count scenario with a 10 NPS pipeline is compared against 3.5" and 4.5" tubing. Individual well rates are equally constrained as necessary in order to inject a total 1.2 mtpa CO_2. Well spacing is 5 km apart along the end of a 70 km pipeline, each with 5 km laterals extended off the main pipeline (Figure 2.1). All scenarios assume a 14.5 MPa compressor discharge pressure.

3.2. Subsurface Scenarios

Bottomhole injection pressure is dependent on the IPR. Lower reservoir permeabilities, higher reservoir pressures, and higher skins increase the required injection pressure for the same rate.

To ensure a 14.5 MPa compressor could deliver sufficient injection pressure under any reservoir subsurface scenario, an extremely low subsurface case was assumed:

- Gas permeability – 20-50 md, based on a 50 md average low case reservoir permeability as assumed by the Quest team.
- Skin – 4-8, based on the fist appraisal well test's range of skin values from 2 to 10, noting that a skin value deemed unacceptable could be lowered via a well intervention stimulation.
- Non-Darcy flow factor – (6.0852e-4)-(7.7852e-4) d/m^3, based on 20 times that of the Prosper calculated value, which is the highest known factor to have been applied to the non-Darcy skin (applicable to typical gas well completions) according to Shell's IPSM GDT.
- Static reservoir pressure – 20.3-26 MPa, based on the simulated increase in reservoir pressure over 25 years of injection.

All combinations of the above sensitivities were run to ensure a 14.5 MPa compressor would be able to provide sufficient injection pressures at the wellhead and top perforation in order to inject at least 1.2 mtpa CO_2.

3.3. Results

GAP was used to show the results of the varying surface scenarios on the ability to inject CO_2 under the different subsurface scenarios.

3.3.1. Four Well Scenario

The pressure losses experienced from the compressor to the last well with a 1.2 mtpa CO_2 throughput across the varying pipeline sizes for a four well scenario are listed below in Table 3.1. The larger the pipeline size, the less frictional loss experienced across the pipeline, resulting in a higher available wellhead pressure (WHP).

Table 3.1 Pipeline Pressure Losses, Four Well Scenario

Pipeline Size	Pipeline ΔP	Available WHP	Maximum BHIP
10 NPS	1 MPa	13.5 MPa	31.9 MPa
12 NPS	0.5 MPa	14.0 MPa	32.5 MPa
16 NPS	0.2 MPa	14.3 MPa	32.7 MPa

Prosper's SRTCA tubing flow correlations (as recommended in the Production Technology CO_2 Guidelines[2]) are used to determine the maximum BHIP attainable based on the available WHP's in Table 3.1.

It is clear that a 14.5 MPa compressor is able to deliver pressures above the maximum allowable BHIP currently assumed to be 28.35 MPa. However, as can be seen in Figure 3.1 below, in an extremely low subsurface case, a pressure exceeding the 10 NPS maximum attainable flowing bottomhole pressure (FBHP) could be required in order to inject the minimum 1.2 mtpa of CO_2.

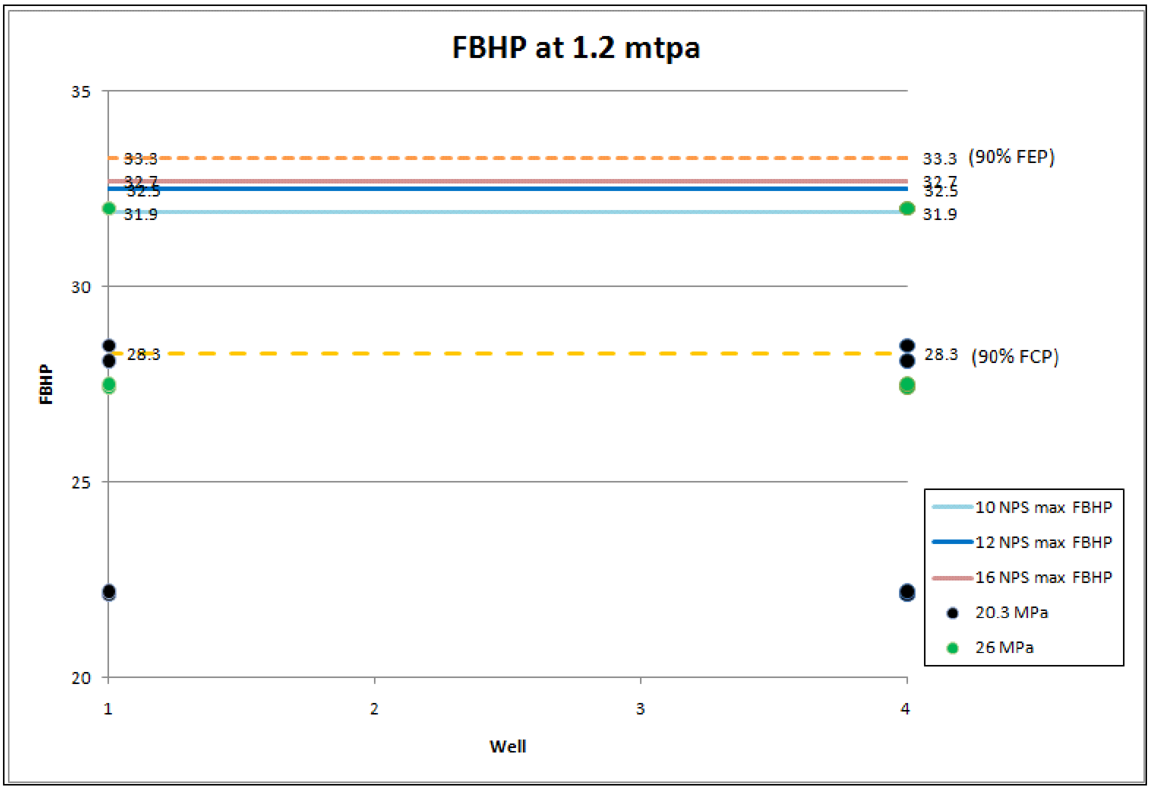


Figure 3.1 FBHP results for a Four Well Scenario

The yellow dotted line in Figure 3.1 represents the most conservative injection limitation (90% of the fracture closure pressure (FCP)). The orange dotted line represents the anticipated injection limitation (90% of the fracture extension pressure (FEP)). The black and green dots represent the varying subsurface scenarios (see section 3.2) run at reservoir pressures of 20.3 MPa and 26 MPa, respectively. There is no apparent change in FBHP's from the first well (Well 1, closest to the compressor) to the last well (Well 4, farthest from the compressor) due to the minimal pressure losses experienced in the pipeline between the wells and the fact that almost every scenario has overly sufficient wellhead pressures needed to inject rates for 1.2 mtpa CO_2, requiring the wells to be injected on a choke.

3.3.2. Five Well Scenario

The pressure losses experienced from the compressor to the last well with a 1.2 mtpa CO_2 throughput across the varying pipeline sizes for a five well scenario are listed below in Table 3.2.

Table 3.2 Pipeline Pressure Losses, Five Well Scenario

Pipeline Size	Pipeline ΔP	Available WHP	Maximum BHIP
10 NPS	1 MPa	13.5 MPa	32.0 MPa
12 NPS	0.4 MPa	14.1 MPa	32.5 MPa
16 NPS	0.2 MPa	14.3 MPa	32.8 MPa

Prosper's SRTCA tubing flow correlations are used to determine the maximum BHIP attainable based on the available WHP's in Table 3.2.

It is clear that a 14.5 MPa compressor is able to deliver pressures that are above the maximum allowable BHIP currently assumed to be 28.35 MPa, and that are well above the required BHIP in order to inject 1.2 mtpa CO_2 in each subsurface case, as shown below in Figure 3.2.

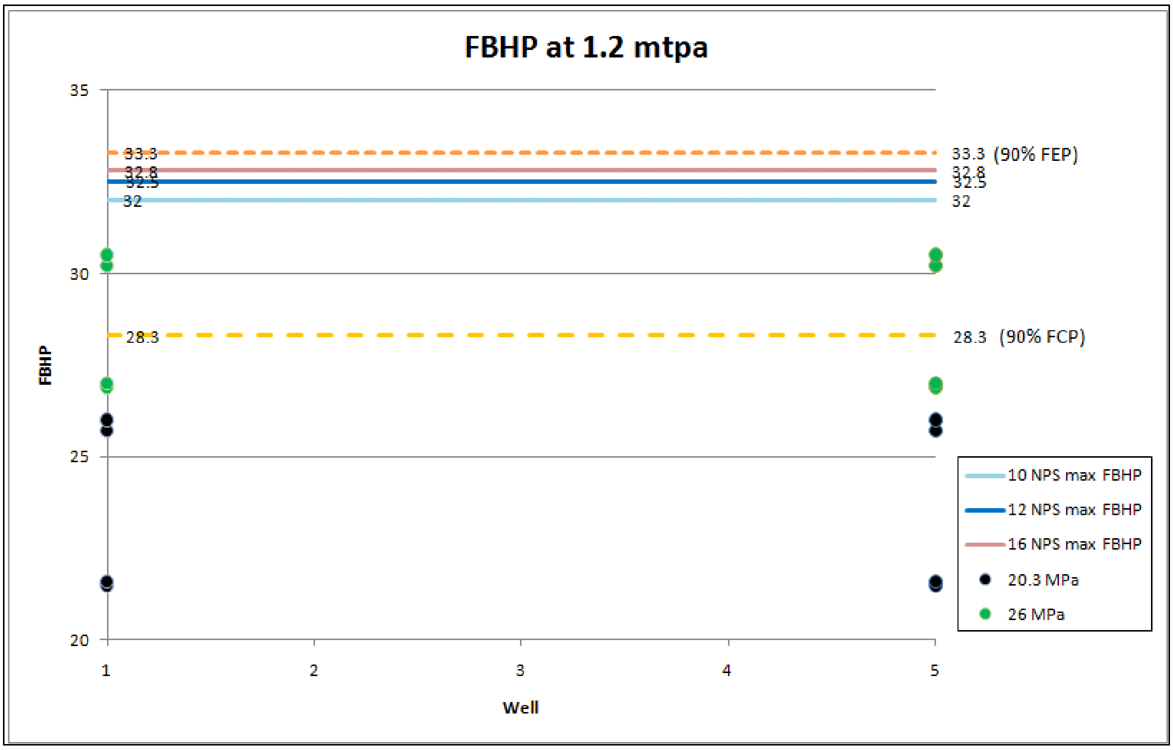


Figure 3.2 FBHP results for a Five Well Scenario

3.3.3. Seven Well Scenario

The pressure losses experienced from the compressor to the last well with a 1.2 mtpa CO_2 throughput across two tubing sizes for a seven well scenario with 10 NPS pipelines are listed below in Table 3.3. Prosper's SRTCA tubing flow correlations are used to determine the maximum BHIP attainable based on the available WHP's.

Table 3.3 Pipeline Pressure Losses for 10 NPS pipelines, Seven Well Scenario

Tbg Size	Pipeline ΔP	Available WHP	Maximum BHIP
3.5" tbg	1.0 MPa	13.5 MPa	31.9 MPa
4.5" tbg	1.0 MPa	13.5 MPa	31.9 MPa

There is no difference in injection requirements between the 3.5" and 4.5" tubing. Typically, as tubing size decreases, pressure losses increase due to the increase in friction pressure for the smaller size tubing. However, rates for 1.2 mtpa CO_2 injection are not large enough to see this affect.

It is clear that a 14.5 MPa compressor is able to deliver pressures that are above the maximum allowable BHIP currently assumed to be 28.35 MPa, and that are well above the required BHIP in order to inject 1.2 mtpa CO_2 in each subsurface case, as shown below in Figure 3.3.

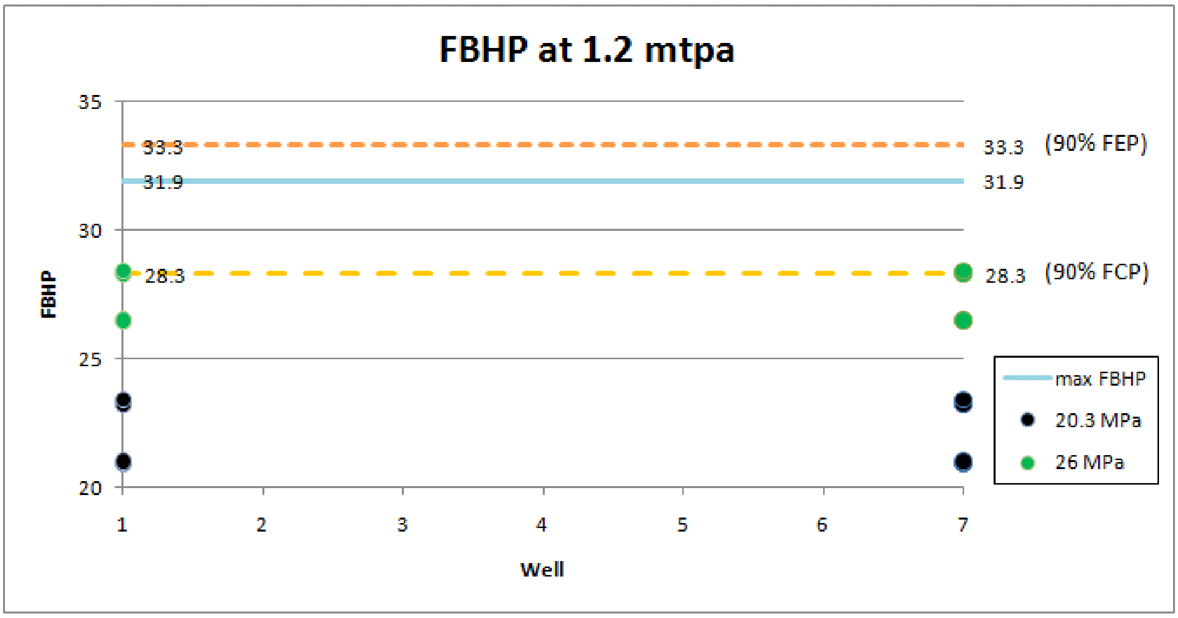


Figure 3.3 FBHP results for a Seven Well, 3.5"/4.5" tubing Scenario with 10 NPS pipeline

3.3.4. Capacity

In addition to providing higher attainable wellhead, and therefore bottomhole, injection pressures, a larger pipeline also provides additional growth capacity.

To model the growth capacity in GAP, the injection rate constraint was removed from each well and the wellhead choke allowed to be changed by GAP's internal optimizer until maximum injection into every well was achieved (i.e. zero wellhead choke).

Higher capacity is achieved with the larger pipeline size and higher well count. Capacities that cover the entire range of subsurface scenarios are listed for each surface scenario in Table 3.4 below.

Table 3.4 Total System Capacity

Pipeline Size	4 Well Count	5 Well Count	7 Well Count
10 NPS	1.1 - 2.4 mtpa	1.4 – 2.9 mtpa	1.7 – 3.3 mtpa
12 NPS	1.2 - 2.9 mtpa	1.5 – 3.4 mtpa	N/A
16 NPS	1.2 - 3.1 mtpa	1.5 – 3.8 mtpa	N/A

3.4. Discussion

The majority of the pressure losses across the pipeline occur upstream of the first well (see Figure 2.1). After the mass flow in the pipeline starts decreasing as the CO_2 is injected into each well, the frictional losses are reduced, resulting in minimal pressure losses to each subsequent well. Because of this, even with a pipeline greater than 70 km, or with greater than seven wells, sufficient wellhead pressures should be available for at least 1.2 mtpa CO_2 injection.

The higher the well count, the lower is the required rate, and therefore BHIP requirements, per well to inject 1.2 mtpa total CO_2. This is why the FBHP results shift down in Figures 3.1-3.3 as the well count scenario is increased from four to seven wells. In the event a seven well count scenario is necessary, the ability to use a smaller size tubing without adversely affecting the BHIP requirements allows for potential cost savings to be realized via a slimmer well design.

Base case economics assume a five well count scenario. In the event a four well count scenario is sufficient, the higher rates per well will increase the BHIP requirements per well. In order to ensure the ability to inject the minimum 1.2 mtpa CO_2, a 12 or 16 NPS pipeline is recommended, which would provide a 0.6 – 0.8 MPa higher attainable BHIP over a 10 NPS pipeline. Pending the subsurface realization, higher BHIP's could be necessary to ensure the minimum CO_2 injection is achieved.

The 12 and 16 NPS pipelines have the same minimum injection capacity for a four and five well count scenario. The 12 NPS maximum injection capacity is already more than double the minimum required 1.2 mtpa amount in both scenarios. In a five well count scenario, a 16 NPS pipeline could achieve up to 0.4 mtpa additional CO_2 injection over a 12 NPS pipeline. The economics and likelihood of this growth potential occurring are further discussed in Document# 07-1-AA-8212-001[1].

3.5. Recommendation

A 14.5 MPa compressor is recommended since in each subsurface case modeled above, it is able to provide overly sufficient wellhead pressures and therefore sufficient BHIP's necessary to inject at least 1.2 mtpa CO_2 in a four, five, or seven well count scenario, and up to 3.4 mtpa CO_2 in a five well count scenario with 12 NPS pipelines.

4. TEMPERATURE SENSITIVITY

It is currently assumed that the CO_2 discharge temperature will be between 31°C and 60°C. Pending the OHTC and temperature of surroundings, the temperature losses experienced across the pipelines could affect the ability to inject CO_2 downhole. As CO_2 injection temperature is increased, CO_2 density is significantly reduced, as can be seen in Figure 4.1 below.

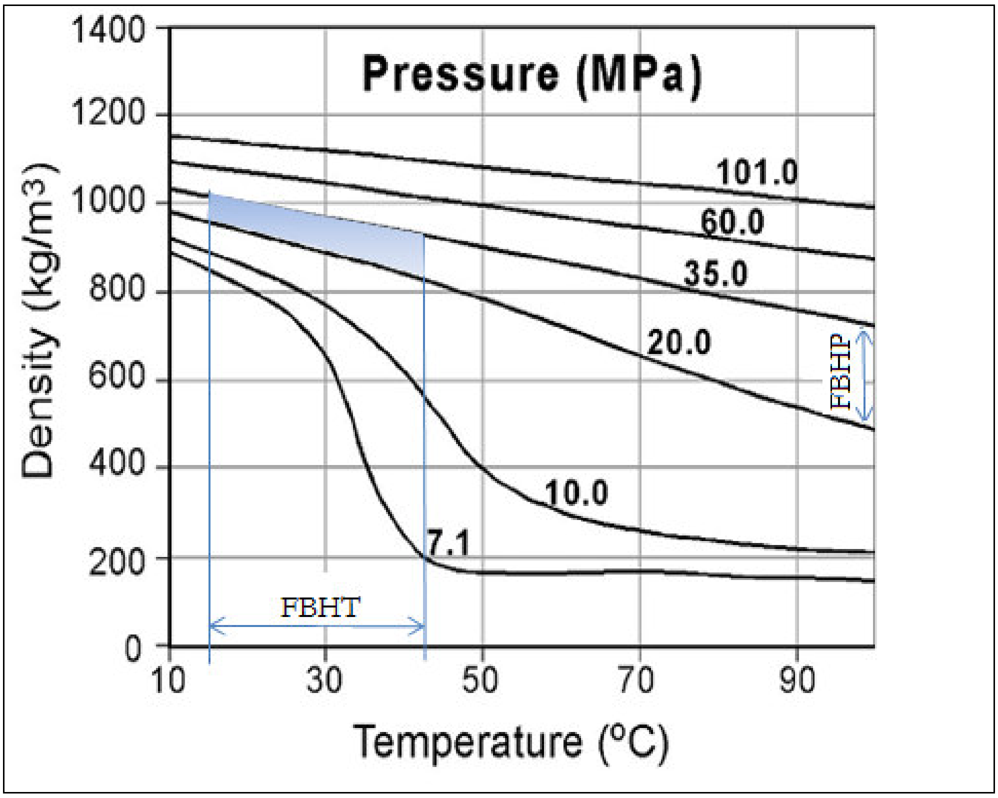


Figure 4.1 CO_2 Density Changes

4.1. Seasonal Scenarios

To capture the range of realistic temperature losses attainable from the compressor to the wellhead, a winter and summer scenario have been modelled for a 31°C and 60°C compressor discharge temperature. The same low case permeabilities and skin are assumed (20 – 50 md and 4 – 8, respectively). In both cases, the non-Darcy factors used have been calculated by Prosper, and the pipeline has been increased to 85 km in length to reflect the most updated 5 well base case surface scenario.

The OHTC chosen for each scenario is based on the range provided by SCAN's Project Engineering group. Quest's pipelines will be externally coated in fusion bonded epoxy for corrosion control against groundwater. Based on lab data performed with this coating, the OHTC ranged from 2 – 6 $W/m^2/K$. This was confirmed using the work of George Zabaras (Sr. Staff Research

Engineer), which predicted an OHTC range of 2.73 – 4.37 W/m^2/K for 12 NPS pipeline for the possible soil thermal conductivities that could be encountered. For modelling purposes, OHTC's of 2 – 5.68 W/m^2/K have been used.

The temperature of surroundings at Quest's proposed pipeline depth is predicted to vary from 0°C - 10°C throughout the year. These numbers are based on analogue soil temperatures available for Peace River, the closest analogue to Quest's area of interest[4].

4.1.1. Summer Scenario

A summer scenario assuming 1.2 mtpa CO_2 injection with an OHTC of 2 W/m^2/K and a surrounding temperature of 10°C is used to model the smallest possible temperature loss across the pipelines, the results of which are shown in Figure 4.2 below.

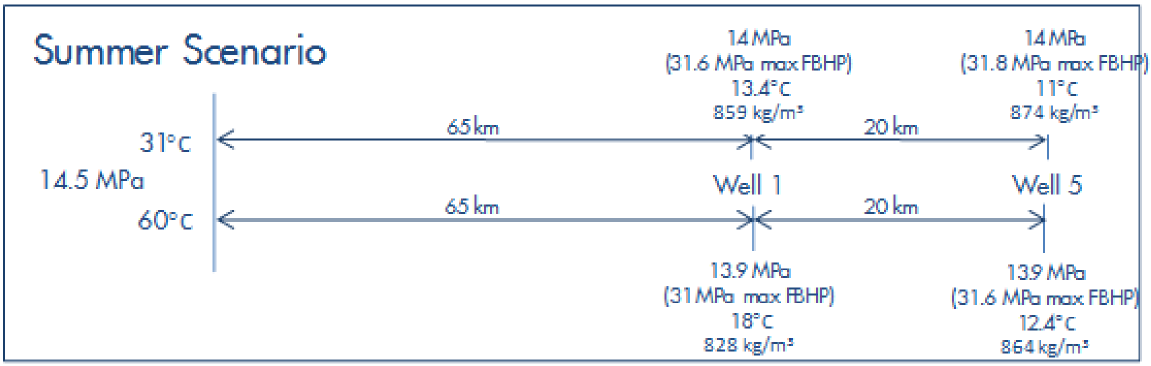


Figure 4.2 Pipeline Temperature Losses, Summer Scenario

In Figure 4.2 above, the maximum available wellhead pressure (i.e. wellhead inlet pressure, upstream of the wellhead choke), maximum BHIP based on the wellhead inlet pressure, wellhead inlet temperature, and CO_2 density at the wellhead inlet pressure and temperature are provided at each well, respectively, for the two compressor discharge temperatures. The pressure and temperature losses across the pipelines can therefore be easily calculated from the compressor to the wellhead.

4.1.2. Winter Scenario

A winter scenario assuming 1.2 mtpa CO_2 injection with an OHTC of 5.68 W/m^2/K and a surrounding temperature of 0°C is used to model the largest possible temperature loss across the pipelines, the results of which are shown in Figure 4.3 below.

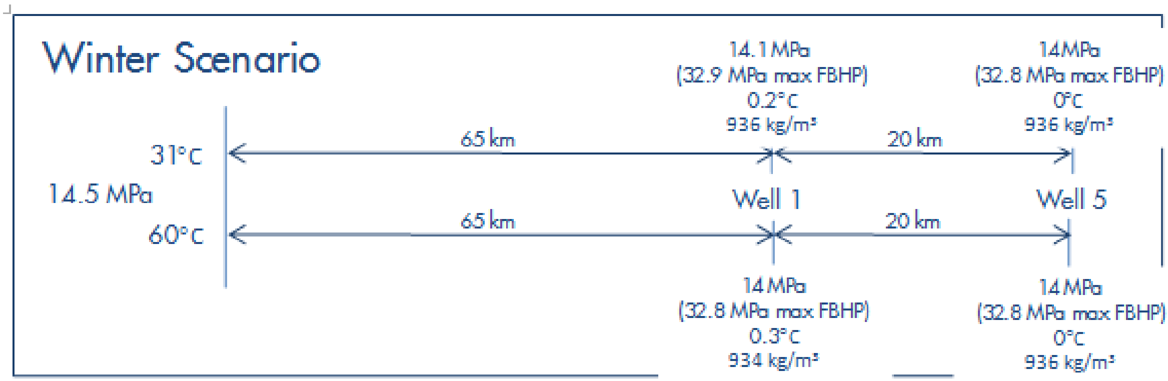


Figure 4.3 Pipeline Temperature Losses, Winter Scenario

4.2. Discussion

The summer and winter scenarios modelled above represent the two extreme cases for pipeline temperature losses. In the winter scenario, the largest OHTC is assumed which more readily allows the fluid temperature to equalize to its surroundings, which is assumed to be 0°C. Both the 31°C and 60°C compressor discharge temperature in this scenario loose all their heat to the surroundings and provide a wellhead temperature around 0°C. In the summer scenario, the smallest OHTC is assumed which allows for the smallest temperature losses and therefore highest wellhead temperatures. In this case, the compressor discharge temperature significantly affects the wellhead temperature and thus the injection capability.

As temperature increases, CO_2 density decreases. To compensate for the loss in hydrostatic head experienced from the less dense fluid, a higher wellhead injection pressure is required to inject the same amount of CO_2. Since more of the available wellhead pressure is required in the summer scenario, a lower maximum bottomhole injection pressure is attainable for the same injection rate, and a lower capacity is achievable with the less available pressure. The lowest compressor discharge temperature provides the lowest wellhead injection temperature, and therefore the highest achievable injection pressure and injection rates.

The maximum wellhead temperature for the above modelled 1.2 mtpa CO_2 injection is 18°C. This temperature is obtained from the summer scenario with a 60°C compressor discharge temperature. In this high temperature scenario, the wells are still producing on a slight choke, meaning there is still room for additional capacity. However, in the event one of the five wells was being serviced and could not inject CO_2, lower wellhead temperatures would be required to increase the fluid density in order for the other four wells to be able to inject the required additional rates. In a four well low subsurface case, a wellhead temperature of 14°C would be required in order to inject the same total CO_2 as in the five well case (Appendix 5).

Injection pressures and temperatures for 1.2 mtpa CO_2 injection and maximum injection (with zero surface choke) for the summer and winter scenarios are shown in Appendix 5. The bottomhole injection pressures and temperatures for these scenarios have also been noted in Figure 4.1 above.

Actual temperature losses will lie anywhere within these ranges, dependant on the OHTC and time of year.

4.3. Recommendation

A 14.5 MPa compressor discharge pressure was assumed in the sensitivity runs above. Separate coolers are required after the gas is compressed to reduce its temperature to an acceptable level for injection. Based on the modelling work performed thus far, though a wellhead temperature of 18°C would be acceptable, a maximum wellhead temperature of 14°C is recommended. This would ensure 1.2 mtpa CO_2 injection is achieved under each subsurface scenario, and that additional capacity is not lost if one well was temporarily out of service for the five well base case surface scenario.

5. CONCLUSION

GAP modeling shows a 14.5 MPa compressor discharge pressure more than adequate to provide the necessary wellhead and bottomhole pressures to inject the minimum 1.2 mtpa CO_2 required for the Quest CCS project for all the surface scenarios modeled. GAP modeling also shows a 14.5 MPa compressor coupled with a 12 NPS pipeline able to provide enough wellhead and bottomhole pressures to inject up to 3.4 mtpa CO_2, pending the subsurface case realized.

The CO_2 injection limitations are therefore not with the compressor size, but with the injection pressure limitation as set by the ERCB. In the extremely low subsurface scenarios (i.e. 26 SBHP, 20 md, 8 skin) the required BHIP exceeds the conservative injection limitation of 28.35 MPa. However, if allowed to inject up to 33.3 MPa, all subsurface scenarios successfully allow at least 1.2 mtpa CO_2 injection at wellhead temperatures up to 18°C. To ensure the highest injection capability under any subsurface and surface scenario (i.e. one well out of service), a maximum wellhead temperature of 14°C is recommended.

The GAP modeling results are in agreement with SCAN's Unisim modeling results. Though the achievable and necessary compressor discharge temperature is still under study, the discharge pressure study is considered complete.

REFERENCES

[1] Sensitivity Study on CO2 Compressor Discharge Pressure, S. Macchia, 07-1-AA-8212-001 (June 2010)

[2] Production Technology CO2 Guidelines DRAFT, M. Bouts, EP 2009-0000 (June 2009)

[3] Government of Alberta, Energy Resources Conservation Board (ERCB), Directive 051, Injection and Disposal Wells—Well Classifications, Completions, Logging, and Testing Requirements (March 1994)

[4] http://climate.weatheroffice.gc.ca/climate_normals/results_e.html?Province=ALTA&StationName=&SearchType=&LocateBy=Province&Proximity=25&ProximityFrom=City&StationNumber=&IDType=MSC&CityName=&ParkName=&LatitudeDegrees=&LatitudeMinutes=&LongitudeDegrees=&LongitudeMinutes=&NormalsClass=A&SelNormals=&StnId=2770&

SI METRIC CONVERSIONS

2 W/m²/K = 0.35 BTU/h/ft²/F

5.68 W/m²/K = 1 BTU/h/ft²/F

14.5 MPa = 2,103 psi

28.35 MPa = 4,112 psi

33.3 MPa = 4,830 psi

5 km = 3.1 miles

70 km = 43.5 miles

31°C = 87.8°F

60°C = 140°F

APPENDIX 1. GAP TECHNICAL ASSURANCE

SIEP – GSU- FESA

Note for File

To: Christa Clark

cc: Mario Winkler

From: Hon-Chung Lau and Keshav Gorur

Date: June 10, 2010

Project: Quest

Re: Technical Assurance Review of CO2 Injectivity Modeling Using GAP

REVIEW – CONTEXT

This Quest CO2 sequestration project is being progressed by P&T-GSU-FESA on behalf of Shell Canada. The current GAP model will be used to ensure that the proposed compressor can inject a minimum of 1.2 million tonnes of CO2 per year for geological sequestration. The purpose of the review to provide ensure that the GAP model that it is fit-for-purpose.

WORK REVIEWED

- Input to and results of multi-well GAP model from compressor to reservoir.

REVIEWERS

- Hon-Chung Lau, P&T-GSU-FESA, Discipline Lead of Production Technology and Chemistry, TA1
- Keshav Gorur, P&T-Wells, Production Technologist

REVIEW – FEEDBACK

- Since the B annulus is cemented to surface, modeling convection in mud (in the drilling and completion screen of the equipment section in PROSPER) is not required. What is done by Christa by not modeling convection makes sense.
- Heat transfer coefficient, viscosity of CO2, pipeline flow correlation, reservoir drainage radius and non-Darcy skin need be modified or re-checked. See detailed recommendations below.

Recommendations

No	Impact (H/M/L)*	Urgency (H/M/L)**	Description
1	H	H	The heat transfer coefficient for the pipeline of 0.35 Btu/hr/ft2/F appears low. Typically a value of 1-2 Btu/h2/ft2/F for gas or 8 Btu/hr/ft2/F for oil is used for a pipeline without insulation that is buried a couple of feet in the ground . Check with George Zabaras who has done a lot of CO2 injection modeling.
2	H	H	For surface equipment, SRTCA is the Shell recommended mechanistic flow correlation to use. Check also with PETEX 4.
3	H	H	Check that the viscosity of CO2 generated by EOS is reasonable. Consult with Birol Dindoruk.
4	H	H	Increase the drainage radius in PROSPER to match with the outer radius of reservoir used by RE.
5	H	H	Increase PROSPER analysis time from 1 day to longer, say 3 months to get to steady state period, where results are not time dependent.
6	M	H	Investigate the effect of non-Darcy skin on CO2 injectivity further. Match well test data on skin. Then run sensitivity on non-Darcy factor.

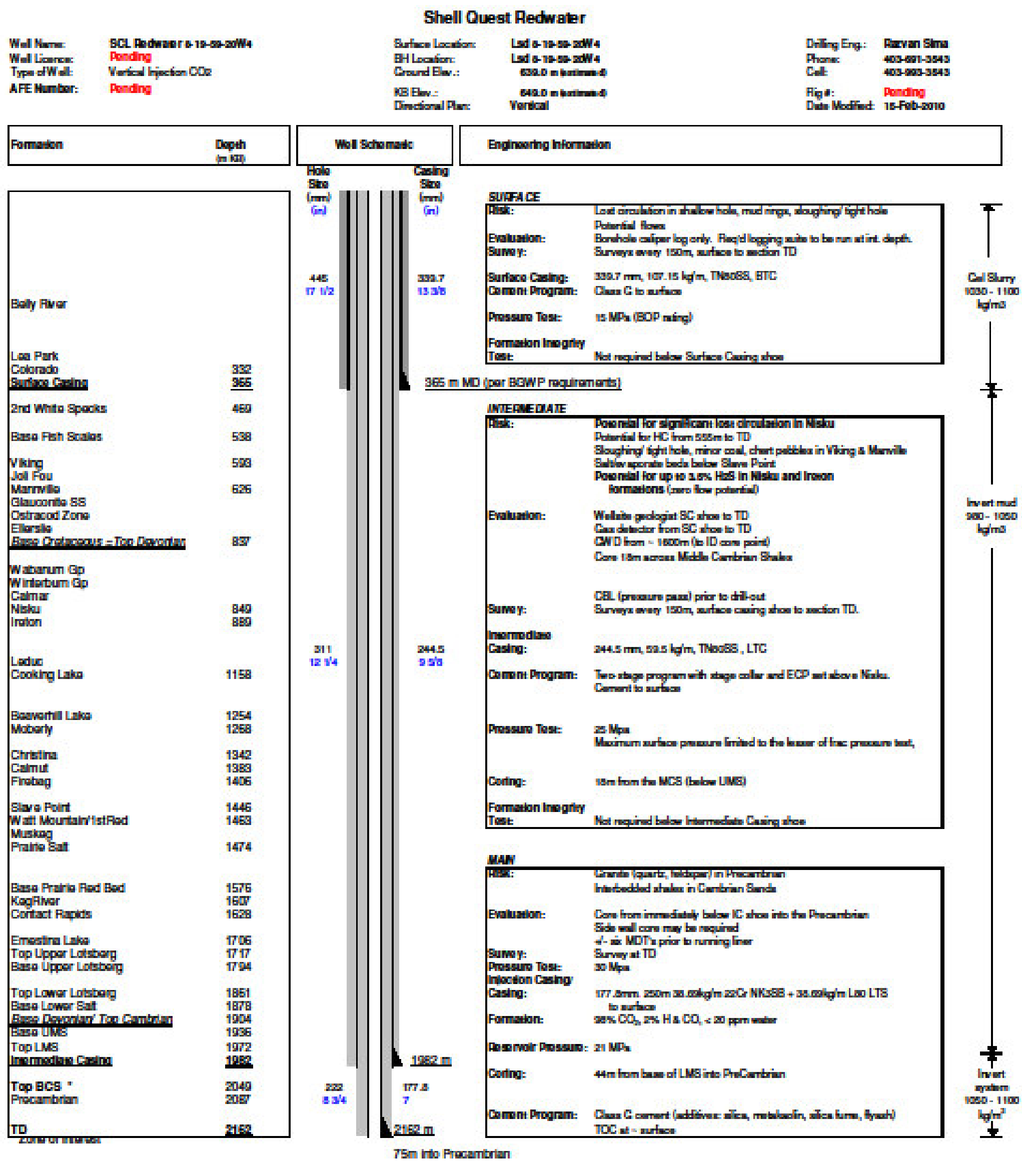
* High, Medium, Low = Impact on project.

** High = Before finalizing decision on compressor, Medium = Shortly after compressor decision is made, Low = Next phase of project.

APPENDIX 2. CO_2 COMPOSITION

		Design Case		30% turndown case	
Stream Description		Stripped CO2 gas from Semi-Lean Still	Cooled Compressed Gas	Stripped CO2 gas from Semi-Lean Still	Cooled Compressed Gas
			with TEG unit		with TEG unit
Total Stream					
Temperature	C	37.1	43.0	37.1	43.0
Pressure	bara	1.5	199.8	1.5	199.8
Molecular Weight	kg/kgmol	42.26	43.30	40.95	41.94
Mass Density	kg/m³	2.48	704.95	2.40	650.70
Mass Flow	kg/h	151913.03	148971.93	55724.52	54614.62
Molar Flow	kgmol/h	3594.96	3440.39	1360.84	1302.34
Water Content	mg/sm³	33113.50	327.36	33177.44	327.41
Water Mass Fraction	ppmw	17789.60	179.02	18392.07	184.89
Water Mole Fraction	ppmv	41727.86	430.29	41805.06	430.36
Hydrate Formation Temperature	C	-19.80	-38.30	-20.11	-34.44
Stream Composition	kgmol/h				
H2O		150.01	1.48	56.89	0.56
CO2		3384.31	3378.27	1235.82	1233.65
CO		1.83	1.83	2.07	2.07
N2		0.17	0.17	0.19	0.19
H2		51.90	51.90	57.62	57.62
C1		6.74	6.74	8.25	8.25
TEG		0.00	0.00	0.00	0.00

APPENDIX 3. QUEST WELL SCHEMATIC



APPENDIX 4. SCOTFORD MINIFRAC RESULTS

The Scotford minifrac was performed in the BCS and the microfracs in the LMS.

The closure pressure is considered the minimum horizontal stress and the most conservative fracture pressure.

MINIFRAC RESULTS AT SCL Redwater 102 11-32-55-21			
	Mini Frac	Bottom Micro frac	Top Micro frac
Depths (m)	2188-2193	2150.5 – 2151.5	2122 – 2123
Breakdown Fracture Pressure (MPa)	47.0	51.5	50
Fracture Extension Pressure (MPa)	45.4	37.9	37
Closure pressure (MPa)	31.5	35.2	33.4

APPENDIX 5. SEASONAL SCENARIO RESULTS

Injection pressures and temperatures for each subsurface low case modelled are shown below for both 1.2 mtpa CO_2 injection and for maximum injection into the five wells.

1.2 mtpa CO_2 Injection:

Cold Case/Winter:

** Assumes 351,000 m3/d into each well*

12 NPS				Well 1 (14.1 Mpa & 0.2°C)*			Well 5 (14 Mpa & 0°C)*			FWHP: 5.6 - 10 Mpa
Comp Output	SBHP	Skin	Gas Perm	FWHP (MPa)	FBHP/32.9* (MPa)	FBHT (°C)	FWHP (MPa)	FBHP/32.8* (MPa)	FBHT (°C)	FWHT: -1 - 1C
14.5 MPa 31°C	20.3 MPa	4	20 md	5.8	22.2	22.3°	5.8	22.2	22.2°	
			34 md	5.7	21.5	24.6°	5.7	21.5	24.5°	
			50 md	5.7	21.1	25.7°	5.6	21.1	25.6°	
		8	20 md	5.9	22.7	20.8°	5.9	22.7	20.6°	
			34 md	5.8	21.8	23.7°	5.7	21.8	23.5°	
			50 md	5.7	21.3	25.1°	5.7	21.3	24.9°	
	26 MPa	4	20 md	9.6	28	15.5°	9.5	28	15.3°	
			34 md	8.9	27.2	15.8°	8.9	27.2	15.6°	
			50 md	8.6	26.8	16°	8.6	26.8	15.8°	
		8	20 md	10	28.5	15.3°	10	28.5	15.1°	
			34 md	9.2	27.5	15.7°	9.1	27.5	15.5°	
			50 md	8.8	27.1	15.9°	8.7	27.1	15.7°	

12 NPS				Well 1 (14 Mpa & 0.3°C)*			Well 5 (14 Mpa & 0°C)*			FWHP: 5.6 - 10 Mpa
Comp Output	SBHP	Skin	Gas Perm	FWHP (MPa)	FBHP/32.8* (MPa)	FBHT (°C)	FWHP (MPa)	FBHP/32.8* (MPa)	FBHT (°C)	FWHT: 0 - 1C
14.5 MPa 60°C	20.3 MPa	4	20 md	5.8	22.2	22.4°	5.8	22.2	22.2°	
			34 md	5.7	21.5	24.7°	5.7	21.5	24.5°	
			50 md	5.7	21.1	25.8°	5.6	21.1	25.6°	
		8	20 md	5.9	22.7	20.9°	5.9	22.7	20.6°	
			34 md	5.8	21.8	23.8°	5.7	21.8	23.5°	
			50 md	5.7	21.3	25.2°	5.7	21.3	24.9°	
	26 MPa	4	20 md	9.6	28	15.7°	9.5	28	15.3°	
			34 md	8.9	27.2	16°	8.9	27.2	15.7°	
			50 md	8.6	26.8	16.2°	8.6	26.8	15.8°	
		8	20 md	10	28.5	15.5°	10	28.5	15.1°	
			34 md	9.2	27.5	15.9°	9.1	27.5	15.5°	
			50 md	8.8	27.1	16.1°	8.7	27.1	15.7°	

OHTC: 5.68 W/m2/K, Surrounding temp: 0C.

Hot Case/Summer:

12 NPS				Well 1 (14 Mpa & 13.4°C)*			Well 5 (14 Mpa & 11°C)*			FWHP: 6.5 - 11.4 Mp
Comp Output	SBHP	Skin	Gas Perm	FWHP (MPa)	FBHP/31.6* (MPa)	FBHT (°C)	FWHP (MPa)	FBHP/31.8* (MPa)	FBHT (°C)	FWHT: 11 - 14 C
14.5 MPa 31°C	20.3 MPa	4	20 md	7	22.2	36.6°	6.8	22.2	34.3°	
			34 md	6.8	21.5	39°	6.6	21.5	36.4°	
			50 md	6.8	21.1	40.1°	6.5	21.1	37.5°	
		8	20 md	7.1	22.7	35°	6.9	22.7	32.9°	
			34 md	6.9	21.8	38°	6.7	21.8	35.6°	
			50 md	6.8	21.3	39.4°	6.6	21.3	36.9°	
	26 MPa	4	20 md	11	28	31.1°	10.7	28	28.3°	
			34 md	10.3	27.2	31.5°	10.1	27.2	28.7°	
			50 md	10	26.8	31.7°	9.8	26.8	28.9°	
		8	20 md	11.4	28.5	30.8°	11.1	28.5	28°	
			34 md	10.6	27.5	31.3°	10.3	27.5	28.5°	
			50 md	10.2	27.1	31.6°	9.9	27.1	28.8°	

12 NPS				Well 1 (13.9 Mpa & 18°C)*			Well 5 (13.9 Mpa & 12.4°C)*			FWHP: 6.7 - 11.9 Mpa
Comp Output	SBHP	Skin	Gas Perm	FWHP (MPa)	FBHP/31* (MPa)	FBHT (°C)	FWHP (MPa)	FBHP/31.6* (MPa)	FBHT (°C)	FWHT: 12 - 18 C
14.5 MPa 60°C	20.3 MPa	4	20 md	7.3	22.2	40.8°	6.9	22.2	35.7°	
			34 md	7.1	21.5	41.9°	6.8	21.5	38°	
			50 md	7	21.1	42.6°	6.7	21.1	39.1°	
		8	20 md	7.7	22.7	40.4°	7	22.7	34.2°	
			34 md	7.1	21.8	41.4°	6.8	21.8	37.1°	
			50 md	7.1	21.3	42.2°	6.7	21.3	38.5°	
	26 MPa	4	20 md	11.5	28	36.7°	10.9	28	30°	
			34 md	10.9	27.2	37.1°	10.2	27.2	30.3°	
			50 md	10.6	26.8	37.3°	9.9	26.8	30.5°	
		8	20 md	11.9	28.5	36.4°	11.3	28.5	29.6°	
			34 md	11.1	27.5	36.9°	10.5	27.5	30.1°	
			50 md	10.8	27.1	37.2°	10.1	27.1	30.4°	

OHTC: 2 W/m2/K, Surrounding temp: 10C.

5 Well Faulted: 85km, 12 NPS, 6" laterals, 4.5" tbg

Assumptions: All wells indentical. CO_2 injection rate per well: 351,000 m^3/d (unless otherwise noted). Buried p/l: 10 NPS = 9.937" ID, 12 NPS = 11.7874", 16 NPS = 373.1 mm, laterals = 6.126". Surface p/l: 3.952" ID. Surface equipment correlation: Mukerjee Brill.
Perforation interval: 30m/38m. Time since production started: 90 days. Calculated non-Darcy flow factor.

Supercritical CO_2: 31°C & 7.4 MPa

Maximum Injection:

Cold Case/Winter:

** Zero surface choke

12 NPS				Well 1**				Well 5**				Capacity (0 choke)	FWHP: 7.8 - 12.8 Mpa
Comp Output	SBHP	Skin	Gas Perm	FWHP (MPa)	FWHT (°c)	FBHP (MPa)	FBHT (°C)	FWHP (MPa)	FWHT (°c)	FBHP (MPa)	FBHT (°C)	MTPA	FWHT: 0 - 8 C
14.5 MPa 31°C	20.3 MPa	4	20 md	10.3	5.7°	26.9	21.2°	9.9	1.9°	27	16.6°	3.8	
			34 md	9	7°	24.9	23.3°	8.6	2.6°	24.9	18°	4.3	vs 3.8 to not drop below 10 Mpa p/l limitat
			50 md	8.3	7.6°	23.6	24.3°	7.8	3°	23.7	18.8°	4.5	vs 3.8 to not drop below 10 Mpa p/l limitat
		8	20 md	10.9	5.1°	27.9	20.1°	10.6	1.5°	28	15.9°	3.5	
			34 md	9.5	6.5°	25.7	22.5°	9.1	2.3°	25.7	17.5°	4.1	vs 3.8 to not drop below 10 Mpa p/l limitat
			50 md	8.7	7.3°	24.3	23.8°	8.2	2.8°	24.3	18.4°	4.4	vs 3.8 to not drop below 10 Mpa p/l limitat
	26 MPa	4	20 md	12.5	2.8°	30.6	16.7°	12.3	0.6°	30.6	14.1°	2.7	
			34 md	11.7	4°	29.3	18.5°	11.4	1°	29.3	14.9°	3.1	
			50 md	11.1	4.7°	28.4	19.5°	10.9	1.3°	28.5	15.5°	3.4	
		8	20 md	12.8	2.2°	31.2	15.9°	12.7	0.4°	31.2	13.8°	2.4	
			34 md	12	3.5°	29.8	17.8°	11.8	0.8°	29.9	14.6°	2.9	
			50 md	11.4	4.3°	28.9	18.9°	11.2	1.2°	29	15.2°	3.2	

12 NPS				Well 1**				Well 5**				Capacity (0 choke)	FWHP: 9.9 - 13.3 Mpa
Comp Output	SBHP	Skin	Gas Perm	FWHP (MPa)	FWHT (°c)	FBHP (MPa)	FBHT (°C)	FWHP (MPa)	FWHT (°c)	FBHP (MPa)	FBHT (°C)	MTPA	FWHT: 16 - 34 C
14.5 MPa 60°C	20.3 MPa	4	20 md	10.1	9.9°	26.3	26.6°	9.7	3.1°	26.7	18.2°	3.6	vs 3.5 to not drop below 10 Mpa p/l limitat
			34 md	8.9	11.7°	24.3	29.5°	8.5	4.2°	24.7	20.2°	3.9	vs 3.5 to not drop below 10 Mpa p/l limitat
			50 md	8.3	12.6°	23.2	31°	7.8	4.8°	23.5	21.2°	4.1	
		8	20 md	10.7	8.8°	27.3	24.9°	10.4	2.6°	27.7	17.3°	3.3	
			34 md	9.4	11.1°	25.1	28.4°	9	3.8°	25.5	19.4°	3.8	vs 3.5 to not drop below 10 Mpa p/l limitat
			50 md	8.6	12.1°	23.8	30.3°	8.1	4.5°	24.1	20.7°	4	vs 3.5 to not drop below 10 Mpa p/l limitat
	26 MPa	4	20 md	12.4	4.9°	30.3	19.3°	12.2	1°	30.5	14.6°	2.6	
			34 md	11.6	6.8°	29	22°	11.4	1.7°	29.2	15.8°	2.9	
			50 md	11.1	7.8°	28.2	23.5°	10.9	2.2°	28.4	16.6°	3.2	
		8	20 md	12.7	3.9°	30.9	18°	12.6	0.7°	31.1	14.1°	2.3	
			34 md	11.9	6°	29.5	20.9°	11.7	1.4°	29.8	15.3°	2.8	
			50 md	11.4	7.3°	28.6	22.7°	11.1	1.9°	28.9	16.2°	3	

OHTC: 5.68 W/m2/K, Surrounding temp: 0C.

Hot Case/Summer:

12 NPS				Well 1**				Well 5**				Capacity (0choke)	FWHP: 9.1 - 13.3 MPA
Comp Output	SBHP	Skin	Gas Perm	FWHP (MPa)	FWHT (°c)	FBHP (MPa)	FBHT (°C)	FWHP (MPa)	FWHT (°c)	FBHP (MPa)	FBHT (°C)	MTPA	FWHT: 13 - 22 C
14.5 MPa 31°C	20.3 MPa	4	20md	11	20.6°	25.9	39.8°	10.7	16.8°	26.1	35°	3.3	
			34md	10.1	21.4°	24.1	41.1°	9.7	17.7°	24.3	36.7°	3.7	vs 3.6 to not drop below 10 Mpa p/l limitation
			50md	9.6	21.8°	23.1	42.3°	9.1	18.1°	23.2	37.6°	3.9	vs 3.6 to not drop below 10 Mpa p/l limitation
		8	20md	11.5	20.1°	26.8	38.9°	11.2	16.3°	27	34.1°	3.1	
			34md	10.4	21.1°	24.8	40.8°	10.1	17.4°	25	36.1°	3.5	
			50md	9.8	21.6°	23.7	41.8°	9.4	17.9°	23.8	37.2°	3.8	vs 3.6 to not drop below 10 Mpa p/l limitation
	26 MPa	4	20md	13	17.5°	29.6	34.8°	12.9	13.9°	29.9	30.2°	2.2	
			34md	12.4	18.7°	28.6	36.6°	12.2	15°	28.8	31.8°	2.6	
			50md	12.1	19.3°	27.9	37.5°	11.9	15.5°	28.1	32.8°	2.8	
		8	20md	13.3	16.8°	30.1	33.8°	13.1	13.3°	30.4	29.3°	2	
			34md	12.7	18.2°	29	35.9°	12.5	14.5°	29.2	31.2°	2.4	
			50md	12.3	19°	28.3	37°	12.1	15.2°	28.5	32.3°	2.6	

12 NPS				Well 1**				Well 5**				Capacity (0choke)	FWHP: 9.9 - 13.3 MPa
Comp Output	SBHP	Skin	Gas Perm	FWHP (MPa)	FWHT (°c)	FBHP (MPa)	FBHT (°C)	FWHP (MPa)	FWHT (°c)	FBHP (MPa)	FBHT (°C)	MTPA	FWHT: 16 - 34 C
14.5 MPa 60°C	20.3 MPa	4	20md	11.3	31.8°	24.6	55°	11	23.5°	25.5	43.7°	2.7	
			34md	10.7	33.1°	23	58°	10.2	25.1°	23.8	46.3°	3	
			50md	10.3	33.6°	22.2	59.2°	9.9	25.7°	22.9	47.6°	3.1	
		8	20md	11.7	30.9°	25.4	53.3°	11.4	22.5°	26.4	42.2°	2.6	
			34md	10.9	32.6°	23.6	56.8°	10.5	24.5°	24.5	45.3°	2.9	
			50md	10.5	33.4°	22.6	58.6°	10	25.4°	23.4	46.9°	3	
	26 MPa	4	20md	13.1	24.9°	28.9	44.2°	13	17.5°	29.6	34.8°	1.9	
			34md	12.7	27.1°	27.9	47.2°	12.5	19.5°	28.6	37.6°	2.1	
			50md	12.5	28.1°	27.4	48.7°	12.2	20.6°	27.9	39°	2.3	
		8	20md	13.3	23.6°	29.4	42.4°	13.2	16.4°	30.1	33.3°	1.8	
			34md	12.9	26.2°	28.3	46°	12.7	18.7°	29	36.5°	2	
			50md	12.6	27.5°	27.7	47.9°	12.4	20°	28.3	38.2°	2.2	

OHTC: 2 W/m2/K, Surrounding temp: 10C.

5 Well Faulted: 85km, 12 NPS, 6" laterals, 4.5" tbg

Assumptions: All wells indentical. CO_2 injection rate per well: 351,000 m^3/d (unless otherwise noted). Buried p/l: 10 NPS = 9.937" ID, 12 NPS = 11.7874", 16 NPS = 373.1 mm, laterals = 6.126". Surface p/l: 3.952" ID. Surface equipment correlation: Mukerjee Brill.
Perforation interval: 30m/38m. Time since production started: 90 days. Calculated non-Darcy flow factor.

Supercritical CO_2: 31°C & 7.4 MPa

In the event one of the five wells was out of service, a lower wellhead temperature would be required to be able to inject the same total rates into the four wells. To illustrate this, the low subsurface case at maximum injection is used. As can be seen below, total system capacity for five wells at 26 MPa SBHP, 8 skin, and 20 md gas permeability is 1.8 mtpa. If this was reduced to four wells, total system capacity would instead be 1.5 mtpa. If, however, the injection temperature was reduced to 14°C, total system capacity would return to 1.8 mtpa, and injection capability would not be lost in the event four wells had to inject the same total volume as five wells in the low subsurface case.

12 NPS				**Well 1****				**Well 5****				**Capacity** (0 choke)
Comp Output	SBHP	Skin	Gas Perm	FWHP (MPa)	**FWHT (°c)**	FBHP (MPa)	FBHT (°C)	FWHP (MPa)	FWHT (°c)	FBHP (MPa)	FBHT (°C)	**MTPA**
14.5 MPa	26 Mpa	8	20 md	13.3	**23.6°**	29.4	42.4°	13.2	16.4°	30.1	33.3°	**1.8**
OHTC: 2 W/m2/K, Surrounding temp: 10C.												

12 NPS				**Well 1****				**Well 4****				**Capacity** (0 choke)
Comp Output	SBHP	Skin	Gas Perm	FWHP (MPa)	**FWHT (°c)**	FBHP (MPa)	FBHT (°C)	FWHP (MPa)	FWHT (°c)	FBHP (MPa)	FBHT (°C)	**MTPA**
14.5 MPa	26 Mpa	8	20 md	13.6	**22.1°**	29.8	40.4°	13.5	16.5°	30.4	33.2°	**1.5**
				13.5	**14.4°**	30.6	30.5°	13.4	12.4°	30.8	28.1°	**1.8**
*** Zero surface choke*												