Non Condensable Gas Reinjection Trial at Ngatamariki Geothermal Power Plant

Shima Abd Ghafar[1], George Allan[1], Alan Ferguson[2], Farrell Siega[1], Manuel Rivera[1], and Bethany Murphy[1]

[1] Mercury NZ Ltd, 283 Vaughan Rd, Rotorua 3010, New Zealand

[2] Contact Energy, Wairakei Power Station, Te Aro Rd, Wairakei 3384, New Zealand

george.allan@mercury.co.nz

Keywords: *NCG, Carbon Emissions, Ngatamariki, Process Design, Trial, Chemistry*

ABSTRACT

As a baseload low emissions source of renewable energy, geothermal development will play a key role in the transition to a low carbon future. On average, the emissions intensity from currently producing geothermal power stations in New Zealand is 73gCO_2e/kWh (McLean, Richardson, Quinao, Clark, & Owens, 2020). While this is significantly lower than many other sources of power generation, there is still an opportunity for the industry to reduce greenhouse gas emissions in the coming years.

This paper describes the feasibility studies and initial results for large scale testing of reinjection of 'Non-Condensable Gases' (NCGs) into the Ngatamariki geothermal reservoir. The testing aimed to trial reinjection of a quarter of the power station's produced NCGs into the brine stream as an opportunity to reduce emissions and evaluate NCG injection as a means of addressing mineral scaling in the formation. Key design considerations from a reservoir, chemistry, and process engineering viewpoint are discussed.

1 INTRODUCTION

1.1 Ngatamariki Field and Power Plan

The Ngatamariki geothermal field is in the Taupo Volcanic Zone (TVZ), in the centre of the North Island of New Zealand**Error! Reference source not found.**. An 83 MWe binary power station was commissioned in 2013, with a resource consent to take up to 60,000 t/d of geothermal fluid. The power station is supplied by three production wells in the centre of the field (NM07, NM12, and NM13), and nominally 100% of produced fluid is injected into up to four injection wells (NM06, NM08, NM09, and NM10) to manage pressure drawdown. The reservoir layout is shown in Figure 1. Ngatamariki is in a compressed liquid state, with production temperatures of 280-290°C and dilute chloride waters with gas content less than 0.3wt%, of which ~95% is CO_2.

The power station consists of four identical OEC ('Ormat Energy Converter') units, each using separated steam and brine to heat and vaporize pressurized pentane, which is used as a motive fluid in the turbine for electricity generation. A simplified Process Flow Diagram of a Ngatamariki unit is shown in Figure 3. Each unit takes roughly 400 t/h brine and 100 t/h steam, producing an NCG exhaust stream of 1 – 1.5 t/h. Following separation of steam and brine, nearly all NCGs remain in the steam. This steam passes first into the vaporizer, where it is condensed to vaporize pentane. Due to their low solubility, NCGs remain mostly in vapour form and must be vented through the existing NCG exhaust system, shown in Figure 2, to maintain heat transfer performance. A control valve on the NCG exhaust system plays a role in controlling steam flow to the units, allowing more NCG (and entrained steam) to escape if pentane is not being heated sufficiently.

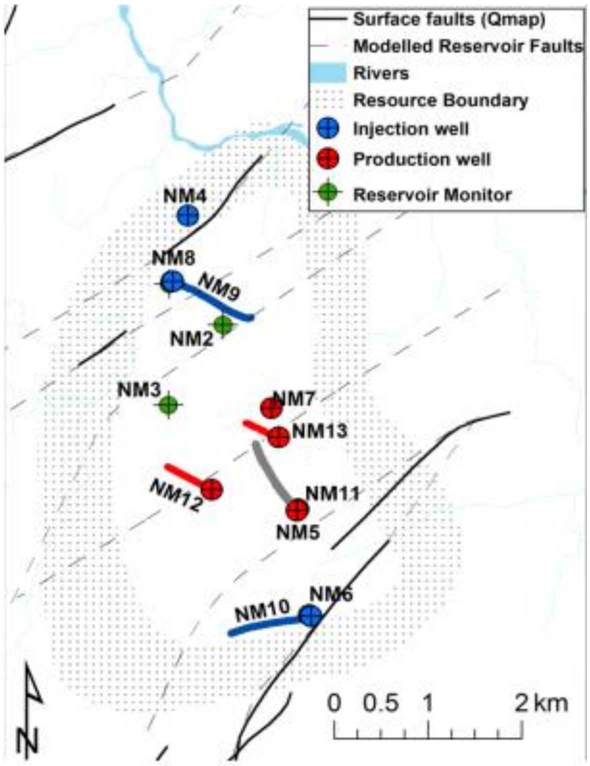

Figure 1: Layout of Ngatamariki geothermal field (Quinao, Buscarlet, & Siega, 2017)

If NCGs are not being exhausted they will accumulate in the vaporizer, acting as an insulating layer slowing heat transfer. The condensed steam is mixed with brine in the preheaters and then the combined geothermal fluid is reinjected. A small portion, approximately 15%, of NCGs are dissolved in the condensate and are reinjected. A small amount of NCG reinjection naturally occurs in this manner in a binary system designed like Ngatamariki, so this trial aimed to expand on this.

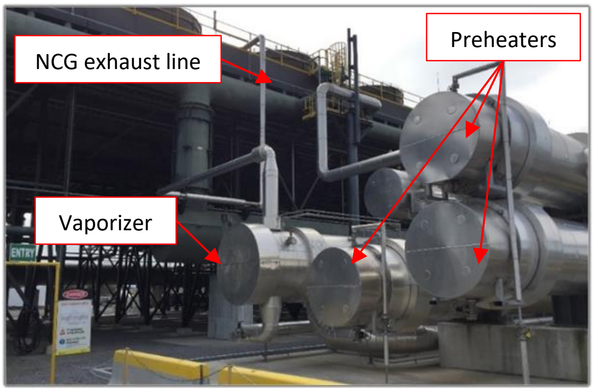

Figure 2: Image of Ngatamariki OEC4, showing heat exchangers and NCG exhaust line to fan deck.

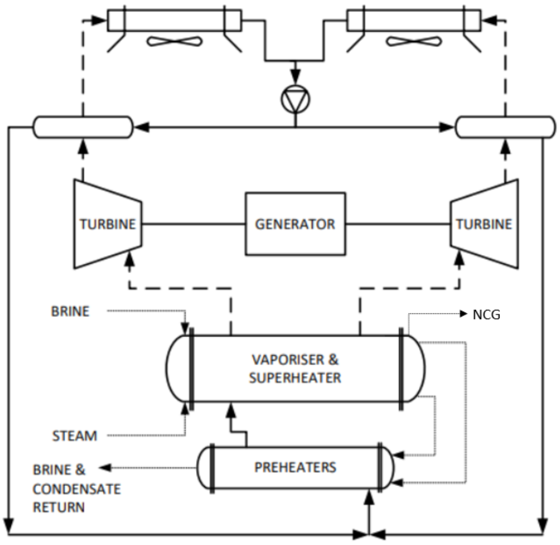

Figure 3: Simplified diagram of a Ngatamariki OEC unit.

1.2 Review of Previous Carbon Dioxide Reinjection

Carbon dioxide reinjection has been modelled, trialled, or implemented at several geothermal fields around the world. Various methods have been used depending on plant technology:

- Flash plant: NCG capture from low pressure turbine exhaust, compressed and be mixed into brine reinjection lines. (Schoonmaker & Maricle, 1990), (Bell, 1988)
- Flash plant: dissolving NCGs in water with a scrubbing tower to preferentially capture CO_2 and H_2S, pumping gas-rich water stream downhole into injection wells. (Gunnarsson, Aradóttir, Sigfússon, Gunnlaugsson, & Júlíusson, 2013)
- Binary plant: keeping NCGs dissolved throughout the whole system by using only liquid.
- Binary plant: injecting compressed NCG mixed with cold brine downhole into an injection well. (Yücetaş, Ergiçay, & Akın, 2018)
- Binary plant: direct injection of NCG into brine pipelines with or without compression, using static mixers to ensure maximum dissolution.

Discussions with some of these operators and a review of published work has highlighted some key considerations. These are summarised below, with their application to Ngatamariki.

1.2.1 Surface Corrosion

Several operators have observed corrosion of surface equipment in contact with NCG's, leading to increased maintenance cost and premature failure of equipment, particularly gas compressors. Possible mitigations are:

- Selection of injection point where reinjection can be achieved through pressure differential between plant steam and reinjection, to avoid gas compression.
- NCG reinjection in a binary plant can be designed to extract NCGs before contact with O_2, reducing risk of corrosion.
- Materials selection of NCG containing lines to address corrosion risk.

1.2.2 Reservoir Gas Concentration

Increased gas concentration due to reinjection could result in lower steam production, inability of surface equipment to manage NCGs, or increased corrosion rate in production wells. (Callos, Kaya, Zarrouk, Mannington, & Burnell, 2015) Numerical modelling shows this is unlikely to occur in the case of Ngatamariki gas reinjection. Two phenomena are understood to cause gas concentration to rise, neither of which are present at Ngatamariki:

- Two-phase or steam cap in reservoir allowing gas to 'short-circuit' to production instead of being dissolved in a liquid reservoir.
- Operating with less than 100% fluid reinjection while attempting to reinject 100% of NCGs, leading to injection fluid containing higher concentrations of NCGs than reservoir.

1.2.3 Dissolution Pressure

The high pressures required to dissolve all NCGs can require high power consumption to compress and high installation costs to inject at depth in reinjection wells. (Bonafin, Pietra, Bonzanini, & Bombarda, 2019) Mitigations in the Ngatamariki case are as follows:

- Ngatamariki NCG concentration is low compared to many fields which have trialled reinjection.
- Calculations described in further sections to assess gas solubility at reinjection pipeline pressures.

1.2.4 Reinjection Well 'Gas-Locking'

This phenomenon is thought to occur if gasses are not fully dissolved at the wellhead, or pressure drop at the wellhead causes gas to come out of solution and build up to a point where flow to the well is restricted. This can be avoided in a several ways:

- Selection of wells which operate at high wellhead pressure for normal flows.
- Design of initial trial system to allow long dissolution time and maintain wellhead pressures above 'gas break-out pressure' so NCG remains in solution.

The trial system will be designed to study the impact of different combinations of NCG concentrations and wellhead pressure to investigate the effect of this and define operating ranges.

1.2.5 Reinjection Pumps

Reinjection of NCG prior to brine reinjection pumps has led to failure or pump performance issues, due to undissolved gas at the pump inlets. This learning has been considered in the system design, with selection of the gas reinjection point to be downstream of reinjection pumps.

1.2.6 Reinjection Well Scaling

It is possible for brine containing dissolved NCG's to react with subsurface rock and deposit carbonate minerals. This approach has been used in the Carbfix project, where geothermal CO_2 is injected and mineralized. (Aradóttir, et al., 2021) While the geology and fluid chemistry at Ngatamariki are not equivalent, the possibility of deposition and loss of permeability has been considered in Section 2.

2 CONCEPTUAL WORK – GEOSCIENCE

Before proceeding into engineering design, several workstreams investigated the geoscience impacts and risks of reinjecting NCGs into the Ngatamariki reservoir to confirm that the project should proceed. The key risks to address were increasing formation scaling and rapid return of gas into the production wells.

2.1 Risk of Increased Scaling

Geochemist's Workbench (GWB) was used to determine the risk of increased scaling in the formation, with reference to autoclave experiments carried out previously on the Ngatamariki injectors. From assessment of the geology in the northern injection area and the results of autoclave testing, it is likely that the dominant water rock interactions will be the dissolution and precipitation of calcite and anhydrite, and the precipitation of amorphous silica.

2.1.1 Impact of additional H2S

The current reinjection brine at Ngatamariki is oversaturated with respect to arsenic sulphides. Arsenic sulphides are known to deposit in the reinjection pipeline and wellbore at Ngatamariki, without impacting generation. When NCGs are added to the reinjection brine, the concentration of H_2S will increase by around 30 mg/kg. GWB calculations suggest minimal changes in sulphide deposition between the two reinjectate compositions, suggesting there is limited risk of negative impacts from increased scaling in the pipeline and wellbore.

2.1.2 Calcite and Anhydrite

As determined from GWB and autoclave experiments, the current Ngatamariki injectate reacts with the formation to reach saturation with respect to calcite and anhydrite. Based on GWB, these water-rock interactions raise the calcium concentration of the injectate to 435 mg/kg. As the fluid moves away from the wellbore it heats up, which causes both anhydrite and calcite to become oversaturated. These minerals will deposit in the formation as the fluid heats up. Evidence of this deposition has been seen in monitoring well NM2, which is close to NM9, where anhydrite deposition was observed on the pressure tubing. To compare any changes in the water-rock interactions upon addition of the NCGs from OEC4, the injectate was modified to include the additional CO_2 and H_2S.

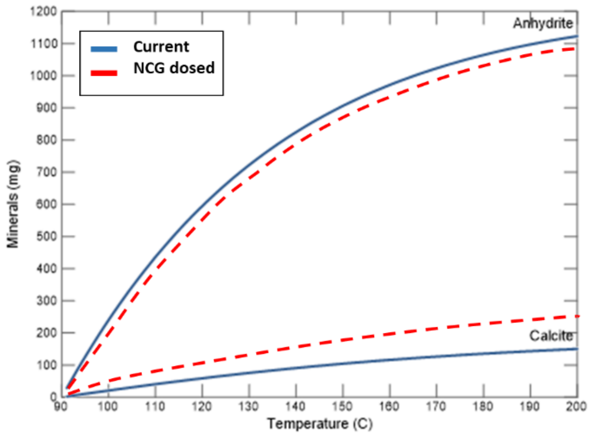

Figure 4: Mineral deposition upon heating from current injectate (left) and NCG dosed injectate (right).

In this case, the calcium concentration increases to 470 mg/kg in the resulting fluid. **Error! Reference source not found.Error! Reference source not found.** shows that the mineral deposition in the NCG dosed case is very similar to that of the current injectate, with slightly more calcite deposited as the temperature increases. This result suggests little change to the calcite and anhydrite deposition risk in the northern injection wells.

2.1.3 Silica

Results from the autoclave experiments on NM09 and NM06 suggest that the cause of silica deposition in the northern injection wells is due to the presence of anhydrite. Anhydrite causes a large increase in calcium concentration, which in turn appears to trigger formation of silicate particles in solution that can then attach to the formation rock. Geochemical modelling in GWB suggests the maximum calcium concentration in the northern injection wells will slightly increase from 435 mg/kg to 470 mg/kg. This small change is unlikely to significantly affect the rate of formation of silicate particles, and hence the amount of silica that is being deposited in the northern injection wells. The main unknown is the impact of reducing the pH of the injection fluid (from ~5.20 to ~4.75). This lower pH may help slow down the process of silica deposition in the northern injection wells. From the literature, using calcium to precipitate silica from geothermal brines is more efficient as the pH increases (Spitzmiller, et al., 2021).

2.2 Gas Returns

The literature review and discussions with operators highlighted the possibility of rapid reinjection returns increasing NCG concentration in production wells – this was observed in both field experience, and modelling investigations. A numerical process model was constructed to investigate this, using EOS2 in TOUGH3. Two injection wells, either side of one production well were used to mimic the rough flow distribution at Ngatamariki, and the trend of declining NCG content in the first 7 years of operation was used to calibrate CO_2 levels, reservoir size, and permeability between production and injection.

Several scenarios were attempted to recreate the reported concentration rise in production wells from NCG reinjection. Some scenarios were able to show the concentration rise – mostly if a two-phase region is developed in the reservoir due to production, or if NCG reinjection is preferentially into one injection well (i.e. injecting higher than the natural reservoir concentration in that well). Neither of this is the case at Ngatamariki, and in a fully liquid reservoir, if NCG concentration in reinjection wells remains at or below the reservoir content, NCG concentration increase in production wells is not considered to be a risk.

3 PROCESS DESIGN CONSIDERATIONS

Following confirmation that risks to reservoir were low, work began to confirm the surface feasibility. Due to the low NCG content and the positive pressure differential between the NCG exhaust and reinjection pipelines, direct injection of NCG's from one unit (OEC4) into the reinjection line was selected as a simple, low-cost option to trial. Several factors which influence the process have been considered throughout the conceptual and detailed design stages. These factors and their impact are summarised below. While some are unique to the conditions at Ngatamariki, others may apply more generally.

3.1.1 NCG Reinjection Pressure

NCGs are taken from OEC4's vaporizer, which typically operates at 12.1 bar-g. The reinjection point should ideally operate at a pressure lower than this supply pressure but higher than the minimum pressure to keep all gases in solution, the latter also known as the gas breakout pressure (GBOP). If a reinjection point pressure higher than the supply pressure cannot be avoided (for example, due to changing reinjection well performance), compression of NCGs will be required. Once injected it is advised to keep all the gases in solution to avoid potential unwanted 2-phase flow behaviour. Therefore, pressures along the system should remain above the GBOP.

3.1.2 Gas Solubility

Gas solubility [mol gas/L water] can be portrayed in the form of Henry's Law constant, k_H, defined below as:

$$k_H = {c_{a,l}}/{p_{a,g}}$$

$c_{a,l}$ = Concentration of species 'a' in aqueous phase [mol/L]
$p_{a,g}$ = Partial pressure of species 'a' in gas phase [atm]

Generally, for gases, solubility decreases with increasing temperature and decreasing pressure. When considering the reinjection point, the point along the system which provides lowest solubility should be determined.

3.1.3 Inline Static Mixer Sizing:

The inline static mixer is an assembly that consists of a sparge pipe and fixed mixing elements inside a housing. The mixing elements are designed to increase turbulence, therefore maximizing gas-liquid contact, which aids dissolution. Provided sufficient time and mixing, complete gas dissolution can be attained if the gas/brine ratio is kept below the gas solubility. Kinetics governing the dissolution rate of NCG in brine is specific to the chemistry make up, and therefore difficult to predict from literature research. However, successful dissolution has been observed in plants with as little as 35s retention time. In comparison, Ngatamariki's NCG injection system allows for approximately 40 minutes retention time. Dissolution rate can also be improved by increasing the gas-liquid contact surface by using a longer mixer or changing its element size. This, however, results in higher differential pressure along the mixer. Given the long residence time and the surplus of line pressure over GBOP (which assists to improve the mass transfer drive) at Ngatamariki, increasing the mixer length or changing its element size is unnecessary.

3.1.4 Control Systems

The current NCG vent control valve is involved in several control loops, each having separate tuning parameters, interlocks, and overrides. To avoid disrupting this, the existing controller shall remain in place, but the output will be modified to fit the new NCG injection valve size and duty. The NCG vent valve demand is mapped to the equivalent valve C_v, at its opening, which is translated to a new C_v required to achieve the same NCG flowrate at the new, lower, differential pressure. This new C_v is correlated to the required valve opening on the new NCG injection control valve. In case of NCG injection failure due to insufficient pressure differential, detected NCG leaks, or manual override, the system will revert to the existing NCG vent valve.

3.1.5 Condensate Build-Up and Drainage

Condensation of entrained steam in the NCG pipeline has potential to cause additional pressure drop in the line due to accumulation in low points or undesirable two-phase flow. Heat transfer calculations suggested insignificant condensing rate along the NCG pipe to the mixing point in normal operation. In the event of higher condensing rates however, gas velocities are expected to be high enough to entrain any water droplets in the gas flow to the mixing point.

Normally the system will be vented back through the original NCG vent when idle. However, if the system is left un-vented when shut down, the total inventory of steam available to condense into liquid is significant, so a low point drain has been included in the design. Considering the service involves hazardous gases, this manual drain point shall be locked during normal operations and accessible only by permit. Consequence modelling and risk assessment was conducted for several scenarios of uncontrolled NCG release of from a vertical silencer connected to the low point drain. This assessment determined that potential risk level is unacceptable and therefore, the need for automated operations draining shall be assessed during commissioning of the system. If required, an operations drain system shall be designed with safeguards and risk analysis conducted prior to implementation.

3.1.6 Surface Corrosion

The addition of NCGs into the Ngatamariki injectate is expected to increase the concentration of dissolved gases and therefore lower the pH of the injectate. With the design basis of adding approximately 1 t/h of NCGs from one OEC unit, the injectate pH will drop from the current measured pH of 5.3 to an expected pH of 5.0. Using GWB, stability diagrams were constructed to assess corrosion potential associated with this process at a reinjection temperature of 93°C.

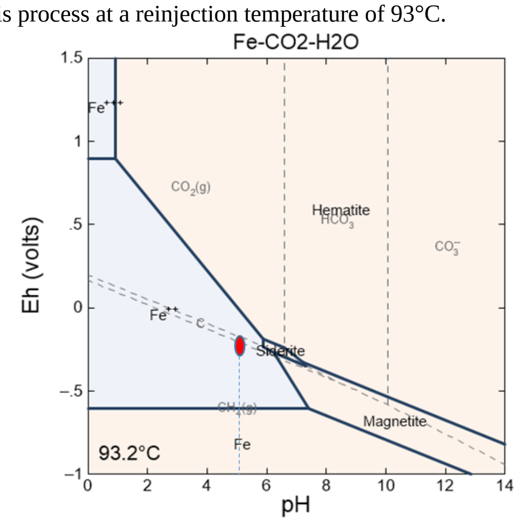

Figure 5: Fe-CO_2-H_2O stability diagram for NCG reinjection into northern brine line.

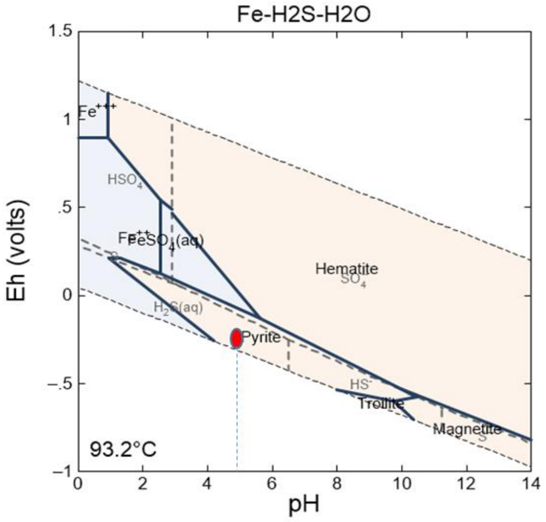

Figure 6: Fe-H_2S-H_2O stability diagram for NCG reinjection into northern brine line.

The stability diagram considering the Fe-CO_2-H_2O system in Figure 5 suggests that the current injectate (separated brine mixed with steam condensate) is already within the zone wherein corrosion is expected. In 9 years of operation, no significant corrosion has been detected in Ngatamariki reinjection pipelines or wells. Adding additional NCGs from OEC4 to the reinjection fluid is not expected to change the corrosion potential significantly. Moreover, considering the Fe-H_2S-H_2O system in Figure 6, the presence of H_2S may lead to formation of pyrite that can act as a passivation layer on the pipeline surface therefore may offer a layer for corrosion protection. The above assessment, however, is mostly based on geochemical modelling and needs to be validated with actual field measurement of the corrosion rate before and after the NCGs reinjection. A plan was put in place to monitor not only the corrosion rate but also assess the type of scale that may form before and after the NCG reinjection trial commences.

4 PRELIMINARY TRIAL RESULTS

Since commissioning in October 2021, various parameters have been monitored to ensure that the new NCG Injection System does not adversely affect the surface, well, and reservoir. Of specific concern were the scaling & corrosion potential of the reinjection pipes and the performances of the OEC unit, station, NCG line, reinjection line, reinjection well, and the production wells. The sections below outline the findings.

4.1 Surface Monitoring

4.1.1 Corrosion and Scaling

Corrosometers and coupons to monitor potential scaling & corrosion were installed at three points along the injection pipeline for the six-month trial period: pre-mixer (prior to the NCG injection point), post-mixer (immediately after the NCG injection point), and at the injection well-pad (approximately 1.5 km from the NCG injection point). Coupons were weighed monthly and analysed using SEM-EDS (scanning electron microscopy & energy dispersive x-ray spectroscopy) at the end of the trial period to confirm the chemical composition; corrosometers were read weekly. Additionally, prior to the trial, a baseline coupon and corrosometer were installed at the injection well-pad for three months to allow comparison.

Results from the trial show that both scaling and corrosion risks on the surface resulting from NCG injection are minimal (Table 1). The pre- and post-mixer coupons both gained a small amount of weight, largely attributed to growth of antimony/arsenic sulphide. The injection well-pad coupon lost a small amount of weight and showed increased iron content in the scale relative to the other coupons, suggesting minor corrosion is likely occurring along the pipeline. The build-up of scale at the injection well-pad is notably less in the NCG trial coupon versus the baseline coupon, suggesting that the slight decrease in fluid pH may result in less scaling potential and a minimally increased risk of corrosion. The corrosometer results, together with UT (ultrasound thickness) testing at various points along the pipeline, support the assessment that the risk of increased corrosion relating to NCG injection is minimal.

4.1.2 Process Stability

The NCG vent valve is involved in several PID control loops – vaporizer pressure, unit generation, NCG temperature, and main steam pressure (MSP). The loop with the greatest error determines the demand. Additionally, each of those PID control loops have several control elements – the element acting depending on how large the error is and may not always be the NCG valve. With this complexity, it becomes difficult to ascertain how much of the unit's stability is contributed by the action of the NCG valve. Therefore, effects of NCG injection on stability of OEC4 has only been generally assessed by comparing the stability of the four PID loops mentioned above and unit efficiency, for the same time of the year, with and without NCG injection. It was found that for all parameters the unit stability did not appear to have been affected by the trial.

Table 1: Corrosion coupon results.

Coupon Location	Type	Weight change (g)	Description
Pre-Mixer	Trial	+ 0.0889	Even growth of antimony/arsenic sulphide with globular/botryoidal texture with low iron content*
Post-mixer	Trial	+ 0.2388	Even growth of antimony/arsenic sulphide crystals with low iron content*
Injection well-pad	Trial	- 0.0072	Mixture of anhedral grains of iron sulphide and antimony/arsenic sulphide*
Injection well-pad	Baseline	+ 0.6032	Predominantly iron sulphide with lesser amounts of antimony/arsenic sulphide and minor amorphous silica

* EDS results not yet available to confirm chemical composition

ISSN 2703-4275

Similarly, several control elements contribute to station wide stability. Therefore, the effects of NCG injection are only generally assessed by comparing the station's MSP and generation, for the same time of the year, with and without NCG injection. Again, it appears that the NCG injection has not affected station stability.

Gross generation from OEC4 and OEC3 were compared both before and after NCG reinjection. During the trial period, OEC4 appears to have slightly lower generation output and more variability, however this is also seen in OEC3, which is unaffected by NCG reinjection, so the slight change is more likely to have been related to ambient conditions or other factors such as heat exchanger fouling. Overall, it is concluded that the NCG reinjection trial has not had significant impact on station stability or generation.

4.1.3 NCG Line Performance

As the NCG exiting the vaporizer contains some entrained water droplets and/or steam, there is a possibility for liquid to form and collect along the NCG line, resulting in potentially unwanted 2-phase behaviour. Additionally, scale build up at the sparge pipe that introduces NCG into the reinjection brine within the mixer could cause back pressure to the NCG line and vaporizer. Therefore, it is crucial to monitor the NCG line "health". This is done by comparing the pressure drop (dP) across the NCG line against a calculated dP and observing the liquid drop pot. The NCG line dP and liquid drop pot levels have not changed throughout the trial period. Condensation in the NCG pipeline does not appear to be an issue.

4.1.4 Reinjection Line Performance

Although turbulent flow is expected, inadequate mixing along the northern reinjection pipeline could allow for NCG to coalesce and form larger bubbles. Even if dissolved, should the line pressure dip at any point along the ~3km line below the gas breakout pressure, NCG could bubble out of solution and coalesce, resulting in gas pockets forming and potential undesirable 2-phase flow behaviour. Further to that, the addition of the static mixer could provide greater surface area for scale to deposit. These risks were identified at design stage and although deemed unlikely, monitoring of the reinjection line performance is necessary to ensure they do not occur. This is done by comparing the dP across the entire reinjection line against a theoretical pressure drop from hydraulic modelling. Figure 7 below shows that there has been no significant change to the reinjection line performance during the trial. Note that when well configurations are changed for operational purposes, a slight difference between the actual and modelled dP is seen, as expected.

4.2 Subsurface Monitoring

4.2.1 Reinjection Well

NCG-enriched brine has been injected in well NM09 exclusively since mid-October 2021. The performance of NM09 has displayed important variations throughout its history attributed to competing processes of permeability improvement due to thermal stimulation and decline due to silica deposition in the formation. Figure 8 presents the injection characteristic changes observed between January 2021 and June 2022. For clarity purposes, the injection capacity of this well will be taken at a reference wellhead pressure of 6 bar-g. In the period between January and September 2021 (prior to the start of NCG injection) NM09 experienced an episode of capacity increase from less than 800 to ca. 1120 t/h, arguably due to thermal stimulation, followed by a slight decrease to 1050 t/h towards December 2021, where it has remained to date. This slight decrease correlates with a temporary period where injection temperature was increased to ca. 100 °C. Overall, and considering the underlying long-term fluctuations in injectivity in this well, data suggests the trial has caused no significant impact on NM09 performance to date.

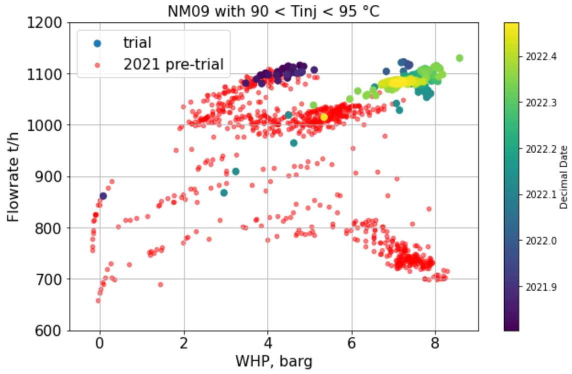

Figure 8: Injection characteristic for NM09 for injection temperature between 90 and 95 °C.

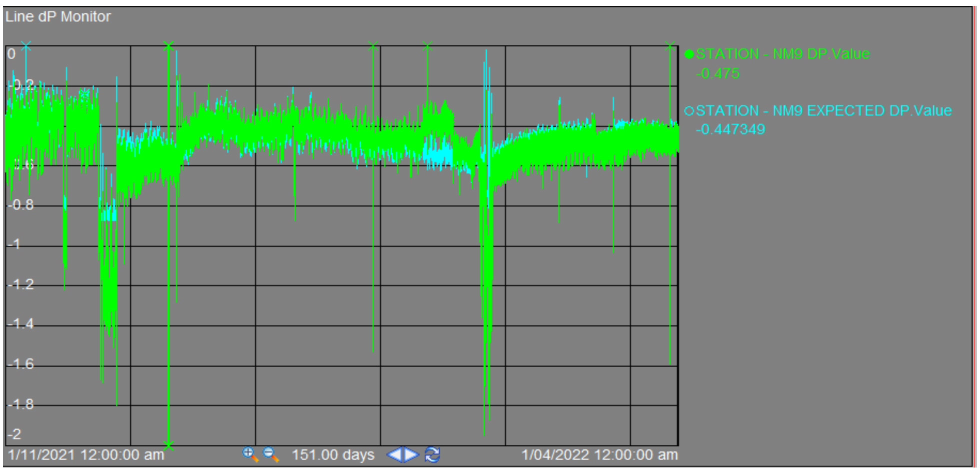

Figure 7: Reinjection line dP, actual (green) vs expected (blue), November 2021 to April 2022

4.2.2 Production Wells

The output characteristics of production well NM07, the closest producer to NM09, have also been monitored to detect any performance changes due to mineral scaling in the formation or the wellbore resulting from a potential change in injection returns chemistry. No changes in deliverability or production enthalpy have been detected up to June 2022. In addition, an X-Y calliper log was run within the production casing of the well in January 2022, 3 months after the start of the trial. The flash depth of NM07 has been kept well within the production casing during the trial. The results indicate no deviation from the nominal internal diameter of the casing, which confirms that no detectable calcite deposition has occurred in this well. Monthly production chemistry sampling shows that the fluid remains below calcite saturation, although there has been a slight increasing trend in CSI (calcite saturation index) from January 2022, coinciding with the expected return rates from NM09. The produced gas concentration observed at NM07 has remained stable during the trial. No performance issues have been experienced at production wells relating to the NCG trial, although monitoring of CSI continues.

4.3 System Tests

4.3.1 Brine Soakage Pond

The northern reinjection well pad is equipped with a soakage pond. This pond is used (rarely) for operational and/or emergency purposes to divert the reinjection fluid away from the reinjection wells. With additional NCGs dissolved in the reinjection fluid, it is expected that should brine discharge occur, there could be higher NCG emissions around the well pad environment.

A test was conducted to measure potential exposure levels. This was done by placing gas detectors at relevant points around the well pad, taking readings pre, during, and post brine discharge to pond. The test was done both with and without NCG injection. Amongst the gas concentrations measured, those for H_2S were of particular interest.

Pre-test	**Brine without NCG**	**Dissipation**	**Brine with NCG**	**Dissipation**
13:10 – 14:10	14:10 – 14:30	14:30 – 14:50	16:32 – 16:52	16:52 – 17:12
0 ppm	13 ppm*	0 ppm	3 ppm	0 ppm

below shows H_2S readings taken close to the brine release point. As flowrates could not be actively controlled to make a fair comparison, it could not be concluded that NCG injection leads to significantly higher H_2S emissions during brine discharge to the pond. However, it was found that discharging cold brine tends to release higher H_2S levels, even without NCG injection. Instantaneous levels higher than the Time Weighted Average (TWA – 5ppm average over 8 hour working day) limit and Short Term Exposure Limit (STEL – 10ppm over a 15 minute exposure), but lower than Immediately Dangerous To Life or Health (IDLH – 100ppm as per US National Institute for Occupational Safety and Health, Centres for Disease Control and Prevention), were observed. (Worksafe, 2022) The highest measured 15-minute average H_2S reading was 0.95ppm, during brine discharge without NCG injection – this is significantly under the STEL.

The current controls for managing H_2S risk are deemed sufficient to deal with any increase in H_2S emissions levels from NCG injection.

Table 2: Maximum measured H_2S concentrations closest to brine release point.

Pre-test	**Brine without NCG**	**Dissipation**	**Brine with NCG**	**Dissipation**
13:10 – 14:10	14:10 – 14:30	14:30 – 14:50	16:32 – 16:52	16:52 – 17:12
0 ppm	13 ppm*	0 ppm	3 ppm	0 ppm

4.3.2 Gas Break-Out

As described in Section 3 above, Henry's Law is used to theoretically determine the pressure required to keep the NCGs in solution, also known as the gas break out pressure (GBOP). The calculations involved, however, make use of constants for binary systems, i.e., water and a specific gas, from literature research. Interactions between the gases or chemical reactions that can occur due to dissolution are not considered. Actual GBOP may vary from those calculated theoretically. Therefore, tests were designed to determine the empirical GBOP. A side stream of injection flow going to the soakage pond was fitted with a sight glass, pressure gauge and a set of valves to manipulate the pressure of the stream. Upon reducing the pressure, pressures at which gas bubbles are first sighted are noted. The test is repeated for different NCG/brine ratios. Figure 9 and Figure 10 below shows the test set up and results. It appears that the theoretical calculations underestimate the GBOP by approximately 0.5 bar, however in normal operation the reinjection line and wellhead operates above both calculated and actual GBOP.

Figure 9: GBOP test arrangement.

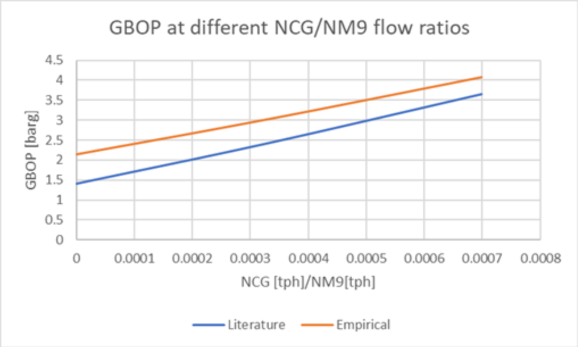

Figure 10: GBOP test results.

4.3.3 Operating Envelope Stress Test

At the time of writing, the Operating Envelope Stress Test has yet to be conducted. It is therefore discussed here in principle, to elaborate the intent and how it feeds into the decision-making process for scaling the NCG Injection System. Ideally, the system is kept at pressures above GBOP throughout to avoid NCGs coming out of solution.

However, Ngatamariki southern injection wells, which take approximately 50% of the station's reinjection flow, operate with much lower wellhead pressures than NM08 and NM09. This has the potential to limit expansion of the system, however there is reason to believe that fluid dynamics can play a role in bringing 2-phase fluid down into the well, even if NCGs are undissolved. The GBOP test conducted indicates that current wellhead pressure in the southern wells is approximately 2 bar below the GBOP of normal injection fluid (without NCG reinjection), but no gas locking has been seen in these wells over 9 years of operation. Therefore, NCG injection may be viable with system pressures below GBOP. The Operating Envelope Stress Test aims to determine the actual limit of NCG injection that would cause significant reduction in injectivity and/or gas locking. This shall be done by varying the NCG/brine ratio with the current trial system until one of the above limits is reached. The current system allows for simulation of NCG injection to the southern wells, and effectively assessing the viability for NCG injection at full station scale.

5 CONCLUSION

A trial system has been designed to inject roughly a quarter of Ngatamariki's NCG emissions. The system was designed with the intent to maximise the chance of success but also to allow the investigation of conditions outside the design envelope to inform possible expansion of the system. This paper has described some of the thought process that has gone into this system and the main risks addressed, however a significant body of work has been done in the design process which cannot fully be captured.

The NCG reinjection system has been in near-continuous operation for 9 months, and preliminary results indicate a successful design and trial. Based on historical gas data for Ngatamariki, the trial is estimated to reduce total station emissions by roughly 8,000 tCO_2e per year. Plant operation has been stable, the system is behaving as expected, and sub-surface monitoring suggests no negative impact to reservoir performance. The learnings and results from this trial will be carried forward to assess expansion of NCG reinjection at Ngatamariki and to other stations.

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