CROSSFIELD GAS PLANT ENERGY EFFICIENCY AND GHG REDUCTION

Final Outcomes Report

Project:	Crossfield Gas Plant Energy Efficiency and GHG Reduction
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TAQA

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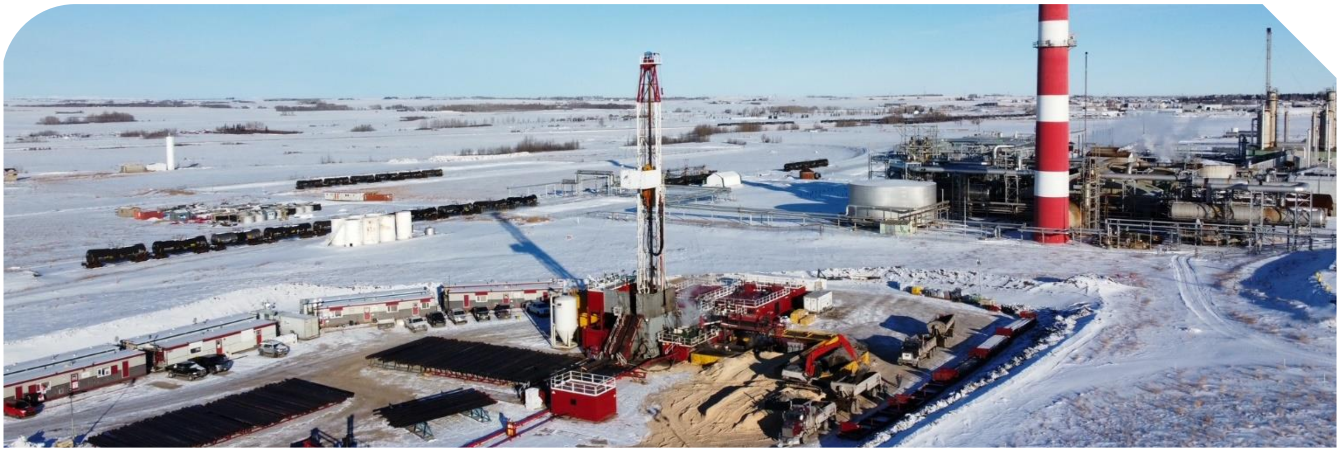

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Executive Summary

TAQA North (TAQA), with funding from Emissions Reduction Alberta (ERA), executed a project at the East Crossfield Gas Plant (ECGP) to convert from sulphur recovery to Acid Gas Injection combined with other energy efficiency improvements.

In addition to making a material reduction in greenhouse gas emissions, this project ensured continued operations for this sour gas processing facility as an alternative to early cessation of operations and accelerated abandonment.

This project would have been economically challenged without the financial support of ERA grant funding made available through the 2018 Industrial Efficiency Challenge.

This project benefits not only TAQA and our facility partners, but other area operators that utilize the ECGP for custom processing of their natural gas, the government and people of Alberta. For the government of Alberta the direct benefit relates to royalties generated from the continued production and sale of oil, natural gas and associated natural gas liquids. The people of Alberta benefit from not only these royalties contributing to the provincial budget, but for direct and indirect employment that is maintained by ensuring continued operations at this facility.

This project has resulted in an initial reduction of approximately 51,500 tonnes of CO_2e per year, which would result in cumulative emissions reduction of between 700,000 and 1,300,000 tonnes of CO_2e by the year 2045 depending on feedstock decline rate. Current natural gas feedstock available to the ECGP suggests that operations could continue beyond 2045, limited only by economics of the day.

Project Description

Introduction and Background

The East Crossfield Gas Plant is operated by TAQA North Ltd. (TAQA) and located at 09-14-028-01W5. The ECGP currently produces saleable products including sweet natural gas, sulphur (pre-project), condensate and liquified petroleum gases from natural gas collected in the surrounding area. Through the facility's process (Figure 1), over 100,000 tonnes of greenhouse gases (GHGs) are emitted annually. The majority of these GHG emissions are associated with the incinerator, boilers, and compressors.

Sour gas production in the area is declining and was forecast to fall below the level required for the facility to efficiently recover sulphur. A review of alternatives to address this situation resulted in the recommendation to convert the Plant from sulphur recovery to Acid Gas Injection (AGI). In addition to converting to AGI, the project includes several other initiatives designed to significantly reduce plant emissions and improve overall efficiency.

Acid gases are those that form an acidic solution when combined with water. Hydrogen Sulphide (H_2S) and Carbon Dioxide (CO_2) are the two acid gases associated with natural gas production and are the byproduct of the ECGP sweetening (amine) process.

Prior to project execution the acid gas stream was processed to yield sulphur for sales; residual acid gas was mixed with supplemental fuel gas and incinerated. Significant quantities of greenhouse gas emissions (primarily CO_2) result from this operation. The project safely directs all the acid gas to compression and subsequent injection back into the producing underground sour gas reservoir from which it originated, located 2.7 km below the surface of the lands that surround the Plant. AGI eliminates the need for sulphur processing, the result being no sulphur production and zero emissions from the incinerator stack. Supplemental fuel gas, which was burned in the incinerator, is no longer required.

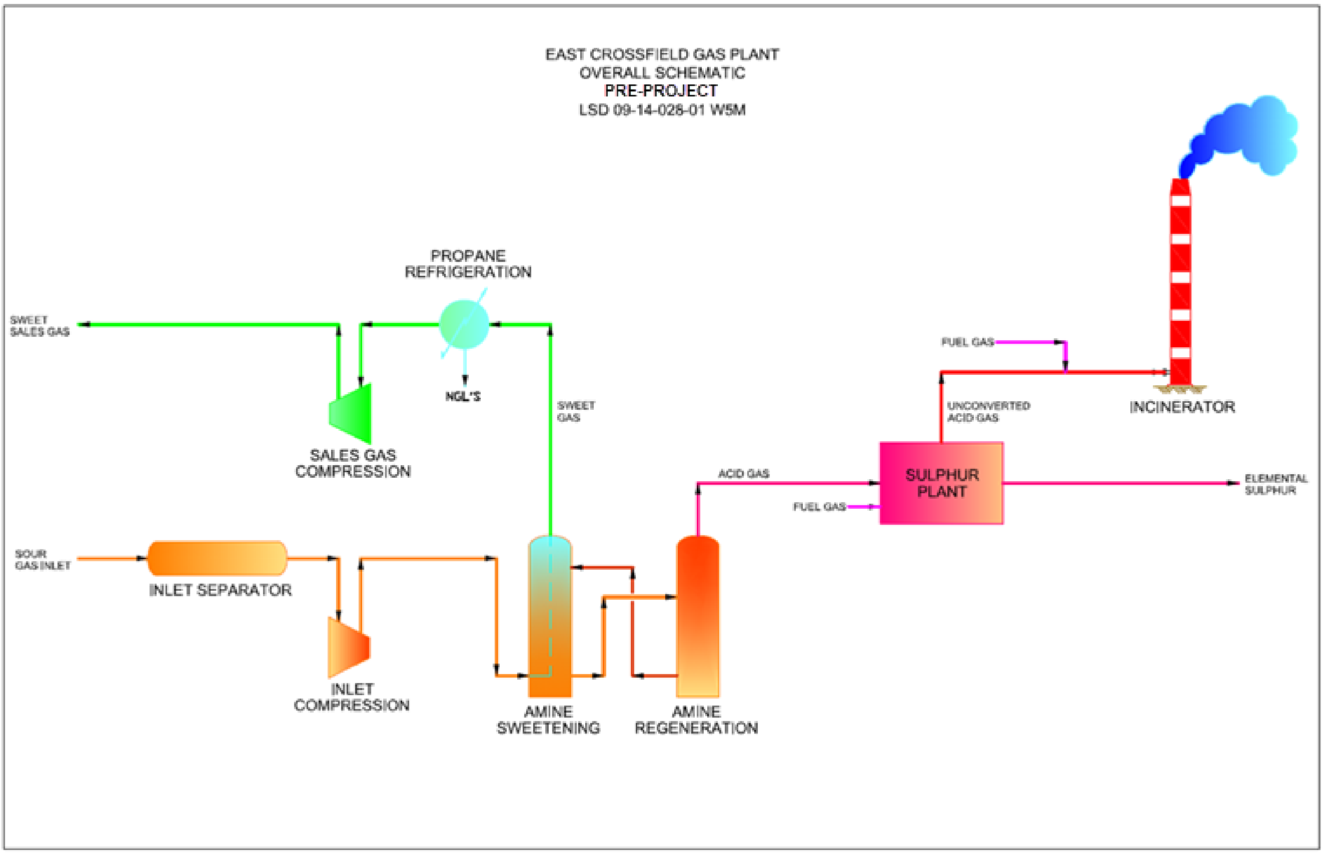

Figure 1: ECGP process schematic (pre-project).

Referring to the clouded areas of Figure 2, all project activities were conducted within the existing plant site and include the following:

- Removing the incinerator stack from operation
- Adding the ability for the plant to compress and inject acid gas
- Modifying Plant process, boilers, and compression to increase energy efficiency
- Drilling an injection well to sequester acid gases.

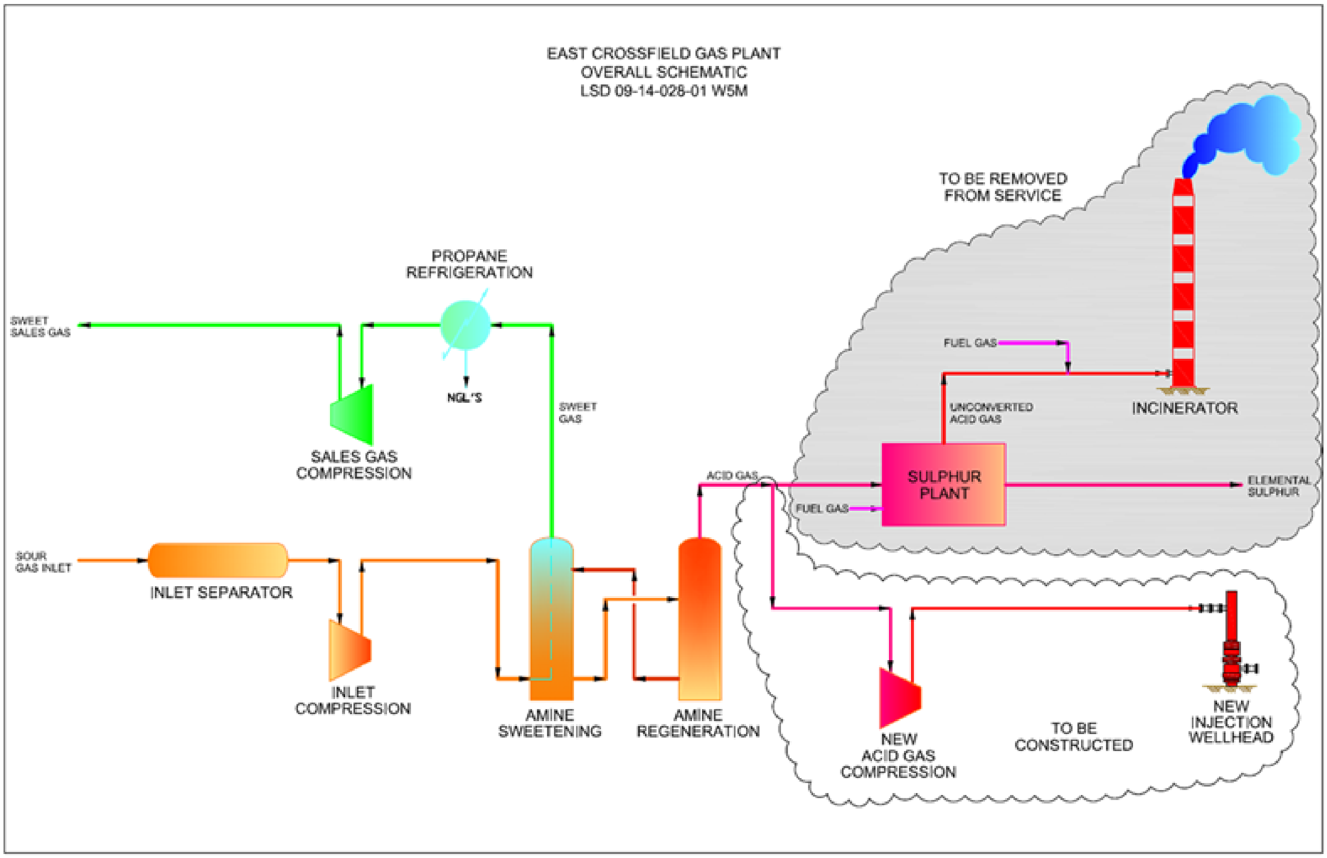

Figure 2: ECGP process schematic (post-project).

Benefits

There are many benefits of the project including:

- *Elimination* of greenhouse gas emissions from the incinerator stack and *Reduction* of total greenhouse gas emissions to approximately 45% of baseline levels.
- *Elimination* of fuel gas consumption required for sulphur recovery operations and significant *Reduction* in total fuel gas consumption for the Plant (-17%).
- *Reduction* of criteria air contaminants (nitrogen oxides, sulphur dioxide, carbon monoxide, volatile organic compounds, and particulate matter) emissions.
- *Continued* economic benefits to the surrounding community and government royalties.

Technology Description

This project employs a combination of existing technologies to achieve the benefits listed in the previous section:

- Drilling a new wellbore directionally from a surface location on the plant site toward a bottomhole coordinate selected for its optimal reservoir characteristics
- Installing new compression designed to handle acid gases and compress to conditions required by the downstream piping, wellbore, and reservoir
- Reconfiguring the internals of the amine regeneration tower to reduce fuel gas consumption and associated emissions
- Reconfiguring sales gas compression to optimize for current and forecast throughput rates, resulting in reduced fuel gas consumption and associated emissions.

The novel component of this assembly of existing technologies is the injection of acid gases into the reservoir from which they originated, while concurrently producing saleable natural gas from offsetting wellbores. The more common approach to AGI is to dispose of acid gases into a deep saline aquifer, which is void of hydrocarbon potential. In these aquifer based AGI operations, injection pressures are high and climb over time. By employing a pressure-depleted natural gas reservoir with concurrent production, this AGI operation operates at reduced injection pressures at surface, thereby reducing compression horsepower requirements and contributing to safe handling of these gases.

This closed-loop production/injection operation will result in permanent sequestration of acid gases (Figure 3).

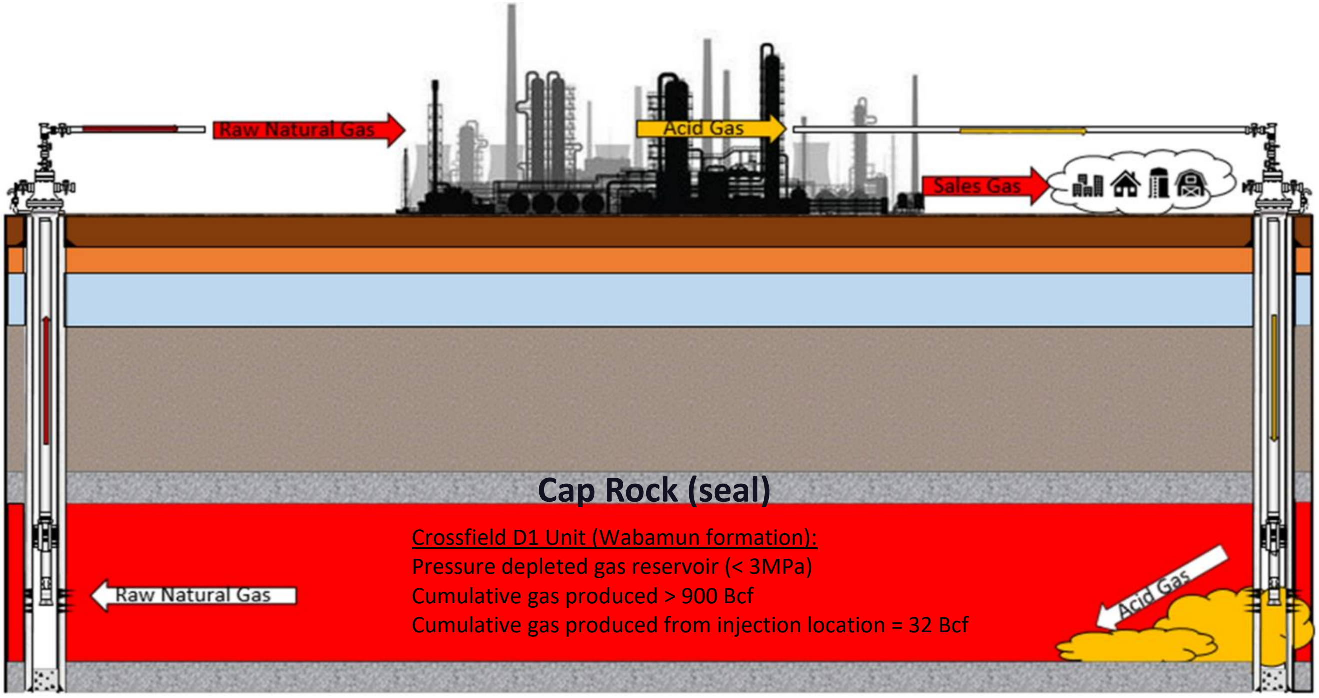

Figure 3: Closed-loop production/injection diagram.

Although not the primary driver nor an expected outcome of this project, there exists potential for an enhanced recovery effect, based on the potential for the injected acid gas (at reservoir conditions) to sweep remaining in-situ native gas, due to a favorable mobility ratio, similar to that which occurs in a waterflood enhanced recovery scheme for an oil reservoir.

Due to the combination of continued low and declining reservoir pressure, inter-well spacing and thick, porous reservoir, any evidence of this potential enhanced recovery effect is expected to take approximately ~3-5 years to be observed at the offsetting producing wells, if ever.

As this project applies a combination of existing technologies (even though the approach and potential outcomes are to some degree novel), on the technology readiness spectrum it is mature.

At the start of this project its Technology Readiness Level (TRL) was 7, as it is based on technologies and techniques that have been proven individually, yet also represents the application of a unique combination (technology demonstration) of these technologies and techniques toward a novel solution with potential enhanced recovery benefit.

At the end of this project the TRL will be 9, representing a successful demonstration of this technology that can be adopted and implemented more widely in industry.

Project Objectives

The objectives of this project as summarized in the Contribution Agreement with Emissions Reduction Alberta (ERA) are as follows:

- Construct and operate carbon sequestration concurrent with production at the ECGP to reduce GHG and SO_2 emissions; and share project outcomes with industry.
- This will be accomplished by a combination of the following:
    - AGI to eliminate incinerator stack emissions; and
    - Optimization of process equipment and compression to minimize emissions related to combustion in the boilers and compressor drivers.

Work Scope

The scope of this project, although complex, is well within the core competencies of TAQA and involves the following major components:

- Drilling a new wellbore directionally from a surface location on the plant site toward a bottomhole coordinate selected for its optimal reservoir characteristics and equipping this wellbore for injection operations
- Installing new compression designed to handle acid gases and compress to conditions required by the downstream piping, wellbore, and reservoir
- Tie-in piping to connect the existing amine process to the new AGI compression and wellbore, and install associated electric power and controls
- Reconfiguring the internals (re-tray) of the amine contactor and regeneration towers to reduce fuel gas consumption and associated emissions

- Reconfiguring sales gas compression to optimize for current and forecast throughput rates, resulting in reduced fuel gas consumption and associated emissions.

Performance/Success Metrics

Performance metrics of this project as defined in the Contribution Agreement with ERA are as follows:

Success Metric:	Project Target:
GHG emission reduction under normal operating conditions from the incinerator stack	100% compared to the estimated project baseline of 33,000 tonnes projected for the year 2021. *
Sulphur Dioxide (SO_2) emission reduction under normal operating conditions from the incinerator stack	100% compared to the estimated project baseline of 1,000 tonnes projected for the year 2021. *
Continuous plant operations	No more than one significant unplanned facility outage per year (greater than 36 hours) under normal operating conditions post completion and commissioning of AGI.

Table 1: Performance/success metrics.

* *The identified baseline includes: direct incineration of the acid gas not converted to elemental sulphur in the sulphur recovery unit and the combustion of supplementary fuel gas to ensure sufficient combustion efficiency for the incinerator. In 2017, the incinerator accounted for 43% of the facility's GHG emissions. As such, the forecast baseline assumes that 43% of the predicted future facility's GHG emissions will be from incineration. In addition, the forecast SO_2 emissions were based on assumed inlet gas volumes and gas analysis at the time of application for funding under this program (2018).*

Project Outcomes and Learnings

Design, Installation and Commissioning

AGI Well Geological and Reservoir Considerations

Geological Considerations

Selection criteria for a suitable subsurface horizon to sequester of acid gases are good porosity, good permeability, along with the absence of natural or induced fracturing to ultimately provide a good reservoir seal, both top and bottom.

The Crossfield East Wabamun A Pool produces from the Crossfield Member within the Stettler Formation, which comprises the majority of the Wabamun Group (Figure 4). The Crossfield Member is composed of dolomite with varying degrees of porosity and permeability within a sequence of non-reservoir facies. The A Pool is one of several similar pools trending generally north-south. The pools are isolated from each other by stratigraphic pinch out of reservoir facies. Regionally, these reservoirs are bounded by dominantly low energy non-reservoir mudstone downdip to the west and evaporites and tight dolomite updip to the east (Figure 5). The Crossfield Member is both immediately overlain and underlain by tight anhydrite and tight dolomite of the Stettler Formation, providing effective top and bottom seals.

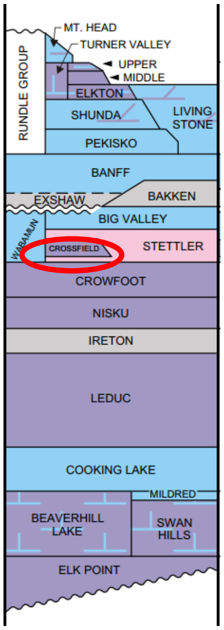

Figure 4: Stratigraphic chart for Crossfield member within the Wabamun Group.

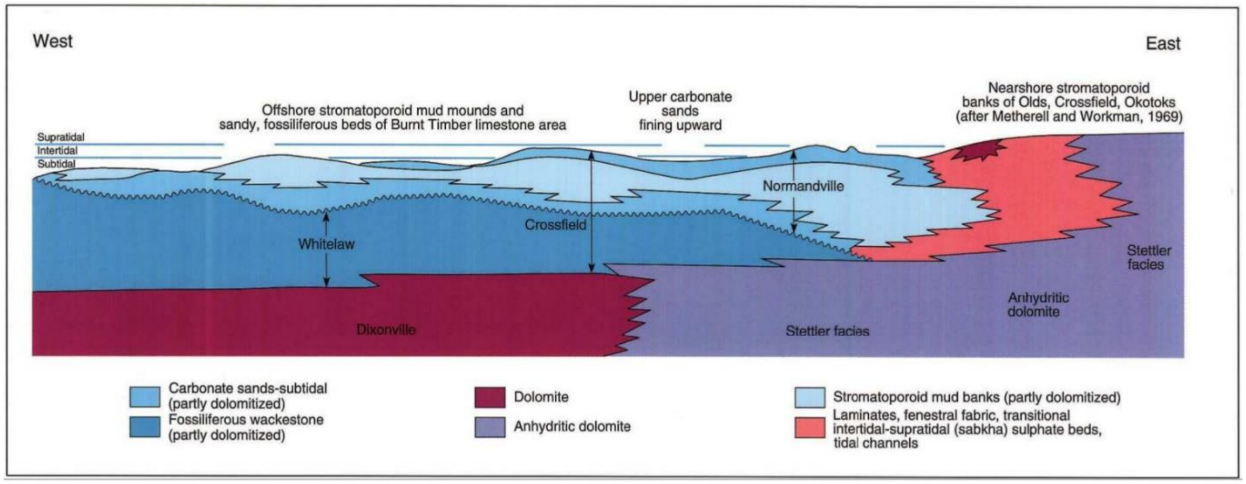

Figure 5: Crossfield Member depositional trend schematic. Modified after Eliuk (1984).

The distribution of the reservoir and non-reservoir facies was influenced by fluctuating water depth. Well log data and core analysis indicate that after the initial deposition of mudstone, there was general shallowing of water during the early deposition of the Crossfield Member that led to the development of porosity subsequent in the depositional process. These deposits form a generally north-south trend that is parallel to the shoreline to the east. The lack of any identified water leg indicates porosity development pinches out in the down dip direction as well.

Reservoir Considerations and Bottomhole Injection Location Selection

The Crossfield East Wabamun A Gas Pool, as defined by the Alberta Energy Regulator (AER) after discovery in 1959, spans multiple townships and is one of the largest Wabamun pools in Alberta, with original gas-in-place (OGIP) estimated at 40,343 e6m3. The East Crossfield Unit, which comprises the southern extent of the Pool has an original gas-in-place (OGIP) estimated at 32,082 e6m3. The Unit has produced a total of 25,878 e6m3 of gas to date with an overall recovery factor of 81%. Wabamun A Pool pressures have declined from an initial value of 24,870 kPa(a) to 2,280 kPa(a) within the East Crossfield Unit in the southern portion of the Pool. The produced gas is highly sour with an average H_2S content of ~40%. The very large OGIP of the Wabamun A Pool which has had significant depletion to date provides very large storage capacity for an Acid Gas Injection scheme. In addition, the location of the East Crossfield Gas Plant on the West edge of the Wabamun A Pool boundary provides an ideal scenario to drill an injection well into the Wabamun A pool. Thus, the Wabamun A Pool was identified as an ideal horizon for implementation of an Acid Gas Injection scheme.

Average reservoir parameters of the Crossfield zone are 13% porosity, 10 to 15 mD for permeability and 10 to 15 meters of net pay. Analysis of the Wabamun A Pool well pressures within the East Crossfield Unit identified four reservoir compartments, each with its own pressure decline signature. Pressure data for the original development wells showed distinct decline trends, with later infill wells following one of the trends. Wells that exhibited the same pressure decline trend were thus grouped together to minimize the scatter in the pressure data to identify each compartment. The largest compartment with the best reservoir quality is located directly to the east of the gas plant and was identified as the optimal location for injection. Historical well tests in the pool were analyzed for evidence of natural fracturing; no such evidence was discovered, ensuring that injection of acid gases in to the Wabamun A pool in the local area will be contained and predictable.

Engineering Design

Well Selection/Design

Once a suitable bottomhole coordinate was selected for injection based on the subsurface considerations outlined in the previous sections, efforts turned to determining whether to utilize an existing wellbore or to drill a new one.

A review of existing wells in the immediate and surrounding area was conducted. Any well with existing perforations in the Wabamun that had not yet been permanently abandoned was considered. From this list of four wells, all of which were drilled in the 1960’s, it was determined that none were suitable primarily due to unknown casing and cement integrity data coupled with the well’s age.

Once it was determined that drilling a new well to service acid gas injection operations was the optimal strategy, work began on the design of the well.

Wellbore Geometry

The first step in the design of the AGI well is determining the surface and bottomhole coordinates, which dictate the wellbore geometry. While the bottomhole coordinates were determined from the geological and reservoir engineering considerations described earlier, the coordinates for the surface wellhead were determined primarily from the perspective of minimizing the health and safety risk to people and the environment.

The goal was to minimize the distance that acid gas is transported between the compression and wellhead equipment via pipeline. A suitable location was found on the southern edge of the East Crossfield Gas Plant, within its boundary. The result was a wellbore geometry that utilized a directional inclination of 34°, targeting a bottomhole coordinate within a 50m radius of known reservoir quality in the existing 100/07-13-028-01W5 well.

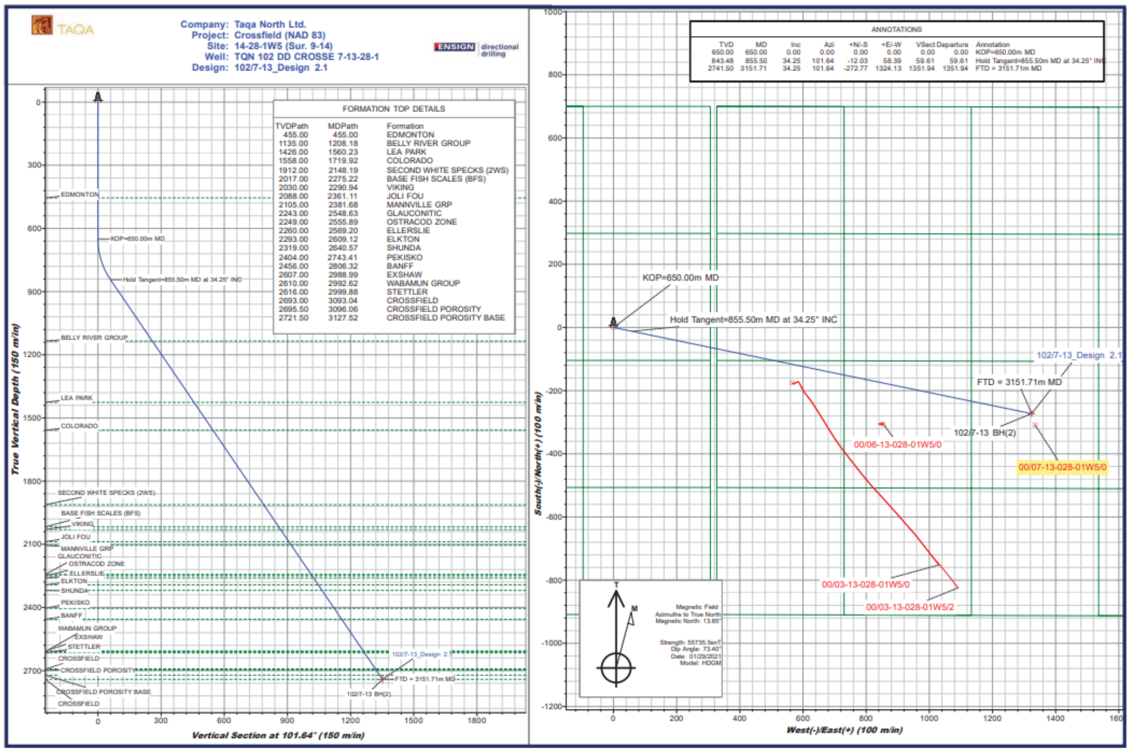

Figure 6: AGI wellbore geometry and directional profile.

Requirements and Nodal Analysis

In determining the injection requirements for the AGI well, several factors were considered:

- Current and forecast total acid gas feedstock rates
- Current and forecast H_2S/CO_2 ratio in feedstock
- Current and forecast acid gas phase behavior, which dictates wellhead injection pressures at a range of injection rates.

The feedstock rate ranges were calculated by forecasting individual wells separately, then combining into an aggregate volume forecast. The H_2S/CO_2 ratio ranges were determined by incorporating individual well gas analyses into the forecast, which was important as the operating life of individual wells vary and the resulting aggregate H_2S/CO_2 ratio over time can vary materially.

Determining the acid gas phase behavior between the surface wellhead and bottomhole injection zone is a non-trivial exercise and is of critical importance to designing upstream compression and dehydration equipment. The Symmetry equation-of-state modelling software from Schlumberger was utilized to model the phase behavior within the wellbore, which yielded a range of expected wellhead injection rates and pressures that were used to design the upstream equipment.

Equipment/Materials Selection

The AGI well tubulars and bottomhole assembly incorporate the following primary components:

- 73.0mm L-80 tubing
- Subsurface Safety Valve (SSSV)
- Permanent packer.

The well casing and tubing are carbon steel. The casing is protected from corrosion above the permanent packer by inhibited fluid filling the tubing/casing annulus. The SSSV, permanent packer and associated components in the tail joint below the packer include a specialty coating for acid gas service. The tubing itself is carbon steel and will be changed out at regular intervals, beginning with two years, and modified based on corrosion evidence after the first wellbore maintenance operation.

Facility Design

As previously mentioned, this project involves the combination of existing technologies configured to achieve the desired result of capturing and sequestering the acid gas stream during the processing of raw natural gas at the East Crossfield Gas Plant (Facility).

The Facility installation consists of the following major equipment:

- Two 800HP electric-drive four-stage Ariel compressors
- Propane chiller
- Acid gas piping
- Emergency shutdown valves

The regeneration tower reflux accumulator is tied to the suction of the compressors. After the second stage of compression, the acid gas is piped to a common off-skid propane chiller. The propane chiller lowers the acid gas temperature entering 3rd stage suction. This is required to prevent the formation of hydrates in the event the discharge piping emergency blowdown valves are required to open. Methanol is injected upstream of the propane chiller to prevent hydrate formation through the chiller.

The propane chiller discharges the acid gas stream to the third and fourth stages of compression. Compressor discharge is metered and piped above ground to the injection well.

All components within the compression, propane chiller, and discharge piping are constructed from stainless steel. The low-pressure piping from the reflux accumulator to the acid gas compressors was existing piping and is constructed from carbon steel.

Analysis of Results

Since commencing operations in early November 2021, the AGI well and associated reservoir have been performing per expectations. Acid gas injection rates and pressures have been within the range of expectations, and within the bounds of the regulatory approval (AER Directives 065 and 051).

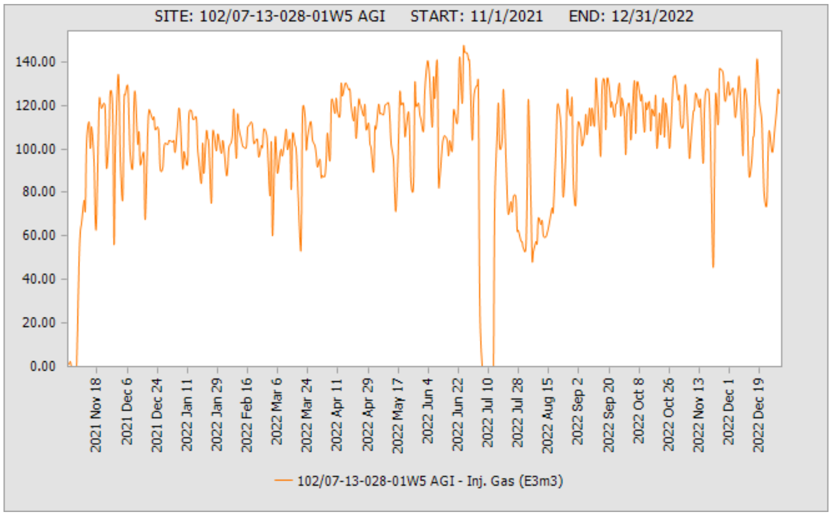

Figure 7: AGI well first 12 months injection rate.

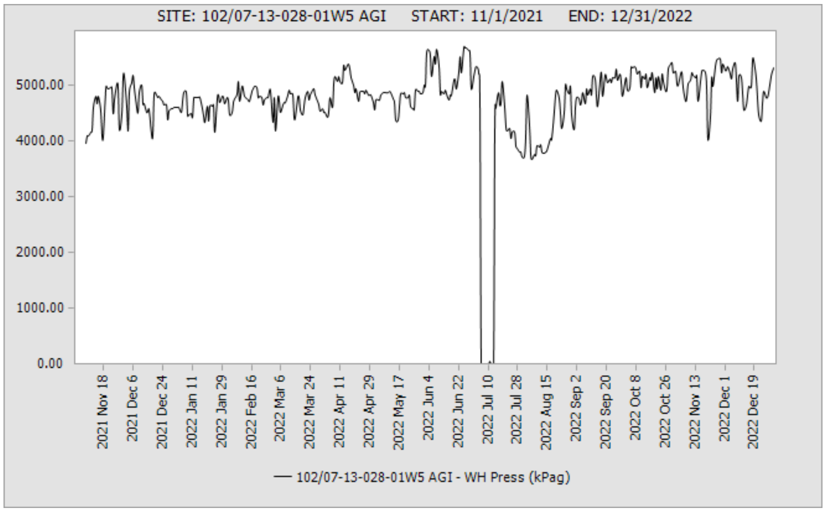

Figure 8: AGI well first 12 months injection pressure.

The other components of the project (reconfiguring the amine contactor and sales gas compression) resulted in a reduction in fuel gas usage at the facility, which when combined with the elimination of all fuel gas consumption in the incinerator resulted in increased energy efficiency for the overall facility.

Status of Identified Risks

The single biggest risk to success identified at the outset of this project was the injection performance of the AGI well and associated reservoir. This risk was mitigated by placing the bottomhole coordinates of the AGI well in close proximity to the bottomhole coordinates of an existing vertical well located at 100/07-13-028-01W5, which corresponds to an area of optimal reservoir characteristics.

As outlined in the previous section, the performance of the AGI well and associated reservoir has met expectations.

Challenges/Delays/Obstacles Encountered

The project encountered challenges with global supply chain shortages of Kalrez, which is a sour service elastomer used in the isolation and safety valves required for the project. This shortage resulted in a 5-week delay of the scheduled plant shutdown for final equipment tie-ins and commissioning of AGI.

At the time of the plant shutdown for final equipment tie-ins, this facility also underwent a major scheduled turnaround. The addition of this separate scope and additional crews to the work site had potential for an impact to cost and/or schedule. In addition, the Covid-19 pandemic and associated safety protocols had the potential to cause material impact to the project schedule. As a testament to the degree of planning involved and professionalism of our contractors, no material cost or schedule delay resulted from either of these.

The project encountered a potential schedule challenge (as compared with budget) related to longer than expected timelines for generating the electrical and instrumentation design and control philosophy. This was a project management issue that was resolved and fortunately did not impact delivery of the project on schedule and budget.

Lessons Learned

Although adequate time was allowed for this project and no material delays were experienced, other operators contemplating such a project should allow for protracted regulatory review and approval processes to ensure the execution schedule remains intact.

TAQA took extra time at the front end of this project to review prior projects for this facility to understand any potential challenges from the regulatory perspective. A project website was developed, and robust project descriptions were communicated to local area residents and businesses ahead of requesting project consent. The result was a public stakeholder that was supportive of this project and understood its intent and benefits.

Greenhouse Gas Benefits

This facility design change has permanently eliminated tail gas incineration and shut down the sulphur recovery process. This eliminates both formation carbon dioxide, and combustion carbon dioxide, from being released to the atmosphere. In addition, the amine sweetening process equipment and the sales gas compressor have been resized. The resizing of the amine processing equipment and sales gas compressor result in a reduction of the volume of fuel gas combusted at the facility.

These initiatives directly reduce the quantity of GHGs emitted to the atmosphere in Alberta. The reduction of GHG emissions is real, demonstrable, measurable, and verifiable using metered and measured data based on proven and accepted protocols for the province of Alberta.

This project supports the province of Alberta in its objective to be economically competitive in a low-carbon economy. By returning formation carbon dioxide to the source reservoir, shutting down a carbon intensive sulphur recovery process, and optimizing existing infrastructure, the Facility has renewed ability to process existing and additional natural reserves for years to come.

Annual GHG Emission Reduction

Initial annual GHG emission reductions are 51,534 tonnes of CO_2e per year. This calculation is generated by comparing estimated GHG emissions for 2022 (first year of operation under AGI) versus 2019 (last full year of routine operation).

	2022	**2019 (Source: 2019 3rd party verified CCIR compliance report)**	**Variance (2022 – 2019)**	**Comments**
Incineration (CO_2e Tonnes)	0	45,553	-45,553	
Stationary Combustion Equipment (CO_2e Tonnes)	54,422	63,371	-8,949	This change is attributed to the process improvement/efficiency changes.
Indirect Electricity (Full facility CO_2e Tonnes)	5,280	2,313	2,967	To be conservative, 100% of this increase is attributed to the impact of the increased electricity required for this project.
Total CO2e Tonnes (incineration, stationary combustion, and indirect electricity)	**59,703**	**111,237**	**-51,534**	
Production Metric: Natural Gas Sales (e3m3)	174,135	204,572	-30,437	Natural gas volume sourced from Petrinex reported dispositions of natural gas at the facility.
Emissions Intensity (CO_2e Tonne / Natural Gas Sales e3m3)	0.3429	0.5438	-0.2009	Emissions Intensity = Total CO_2e / Natural Gas Sales (e3m3)
Emissions Intensity (CO_2e Tonne / Natural Gas Raw e3m3) *	0.2452	0.3795	-0.1343	Emissions Intensity = Total CO_2e / Natural Gas Raw (e3m3)

Table 2: Annual GHG emissions reduction outcome.

* **Although using sales volumes to calculate emissions intensity is common practice, the emissions intensity has also been calculated using raw gas volumes so that this metric can be applied to the market analysis in the Commercial Roll Out section.**

These calculations were based on a methodology that has been reviewed by, presented to, and accepted by the Alberta Climate Change Office (ACCO). The methodology for the emissions also meets the standards outlined in the Alberta Greenhouse Gas Quantification Methodologies Version 2 (December 2011) and ISO 14064-1:2018 (Canadian Standards Association, 2018). The third-party verification was completed to ensure that the GHG statement satisfies the following documents:

- ISO 14064-3:2019 Specification, with guidance for the verification and validation of greenhouse gas statements,
- ISO 14064-1:2018 Specification, with guidance at the organization level for quantification and reporting of greenhouse gas emissions and removals,
- Accreditation Standards: ISO 14065:2013, ISO 14066:2011,
- TAQA North's Measurement, Monitoring and Verification (MMV) Plan, and
- ERA Greenhouse Gas Verification Requirements and Guidance (August 2022).

Baseline Scenario Justification

When this project proposal was submitted in 2018, 2017 was chosen as the most current year where the Facility had typical production and emission volumes for the entire year. The 2017 GHG calculations have also passed third party verification with reasonable assurance.

This report includes a summary of 3rd party verified GHG emissions for the years 2019 (last full year of routine operation) and 2022 (first year of operation under AGI) for the purpose of verifying project GHG emissions reductions and forecasting estimates for a broader market roll out of this combination of technologies.

Estimated Annual GHG Reductions for Commercial Roll Out

The GHG reduction for commercial rollout of this technology in the Alberta market is presented for the years 2025 – 2045.

The commercial rollout is based on implementing this project at other sour gas processing facilities in Alberta that currently employ a sulphur recovery process. These facilities are likely to have experience in GHG reporting and verification; and have established methods for measuring, calculating, documenting, and reporting GHG emissions. As sulphur recovery is already occurring at these facilities, the project rollout will be from actions not required by law and can be considered additional for the province of Alberta.

The methodology used to select the potential sites for this technology included the following:

- A search for all AER category E600 licensed sulphur recovery facilities was completed.
- Of the E600 facilities, some of the sites were abandoned or otherwise not in service and therefore removed.
- The remaining facilities were further filtered to include only those in close proximity to a reservoir of a certain size (greater than ~25 Bcf).

The resulting list included the following 13 facilities:

Facility Location	Facility Name	Facility Licensee
09-27-031-04W5	Hamattan	Altagas Ltd.
02-04-021-04W5	Quirk Creek	Caledonian Midstream Corp.
06-16-026-05W5	Wildcat Hills	Canlin Energy Corporation
01-01-078-10W6	Progress	Canadian Natural Resources Ltd.
02-05-044-01W5	Rimbey	Keyera Energy Ltd.
04-08-075-07W6	Sexsmith	Ovintiv Canada
12-35-034-06W5	Caroline	Shell Canada Ltd.
13-13-025-05W5	Jumping Pound	Shell Canada Ltd.
01-12-062-20W5	Kaybob South	Energy Transfer Canada
03-15-059-18W5	Chevron Kaybob	Energy Transfer Canada
04-11-053-18W5	Edson	Repsol Oil & Gas Canada Inc.
04-31-048-12W5	Brazeau River	Tidewater Midstream & Infrastructure Ltd.
06-18-032-01W5	Garrington	Whitecap Resources Inc.

Table 3: Alberta facilities selected for estimate of commercial roll out potential.

Emissions reduction estimates for the identified facilities above were generated by using the realized emissions intensity (tCO_2e/e^3m^3) reduction from this project as a proxy for the potential emissions reductions by implementing AGI. The emissions intensity reduction (calculated using raw gas volume) for this project was calculated at -0.13 $tCO_2e/e3m3$, resulting from the difference in emissions intensity between 2019 (last full year of routine operation) at 0.38 tCO_2e/e^3m^3 and 2022 (first full year of operation under AGI) at 0.25 tCO_2e/e^3m^3.

The following assumptions were applied to the Alberta market commercial rollout estimate:

- Facility production was taken as the average raw gas rate (e^3m^3) for the month of November 2021, from public data.
- Annual facility raw gas decline rate was estimated at 5%/yr. Some facilities exhibit inclining or sub-5%/yr annual decline rates in late time, therefore by estimating a 5%/yr decline the forecast is somewhat conservative.
- It is assumed that the identified reservoir proximal to each facility is suitable for acid gas injection. No technical analysis was performed to verify this.
- Project life was from 2025 – 2045 for each facility.

The resulting GHG reduction estimates for a market rollout in Alberta are summarized in Table 4.

Aggregate Estimated GHG Emissions Reduction (tCO_2e)					
2025	2026 - 2030	2031 – 2035	2036 – 2040	2041 - 2045	Total
2,000,000	**8,700,000**	**6,700,000**	**5,200,000**	**4,000,000**	**26,600,000**

Table 4: Estimated GHG reductions for Alberta market commercial roll out.

Economic and Environmental Impacts

Projected Economic Impacts

Execution of this project has avoided early cessation of plant operations and associated well production, allowing for future economic benefits to both plant owners, third-party operators utilizing plant processing capabilities, the government, and people of Alberta.

For plant owners and third-party operators utilizing ECGP processing capabilities, the economic benefit is immediate and material. The value of natural gas and associated natural gas liquids reserves for the wells utilizing the ECGP is in excess of the project cost, and ongoing plant operations ensures that future reserves additions can be contemplated for the area.

For the government of Alberta, the direct economic benefit comes in the form of future Crown royalties on reserves produced from Crown mineral rights in the area.

The economic benefit to the people of Alberta, and indirectly the government of Alberta via taxes, is in continued employment and stimulation of the local economies. The ECGP is located adjacent to the town of Crossfield and is near the city of Airdrie, Alberta.

By executing this project and extending the operating life of the ECGP and associated wells, TAQA has maintained 25 FTE (Operations, Maintenance and Administration) positions. Indirectly, continued operations for the ECGP supports third-party vendors and service providers in the area, including but not limited to, trucking, pressure truck services, mechanical maintenance, and asset integrity services. TAQA estimates that ongoing operations supports approximately 4 FTE positions with these companies. In addition to these benefits, continued operations contribute to the local economy of the town of Crossfield (restaurants, shops, services, etc.).

Environmental Benefits

The environmental benefits of this project relate to the local airshed. The direct reduction in GHG emissions by 51,534 tonnes of CO_2e is the equivalent of taking ~11,200 cars of the road, assuming an average 4.6 tonnes CO_2e per year per vehicle (Auto$mart - Learn the facts: Fuel consumption and CO2, 2014).

Overall Conclusions

Overall, this project can be considered successful in that it achieved the desired outcome and the AGI system is operating safely and within the bounds of predicted rates and pressures.

The success of this project is a testament not only to the technical rigor that went into the design and planning, but in the great partnership between TAQA and Emissions Reduction Alberta.

This project is repeatable at other similar operating facilities in Alberta, or other jurisdictions. Feasibility of implementation in whole or in parts at other facilities will require much technical work to verify the environmental and economic benefits. In addition, any such project will need to assess the availability of a suitable reservoir that can be used for sequestration.

Next Steps

Part of this project is potential for a limited, localized enhanced recovery effect, which exists as a result of concurrently injecting acid gas and producing raw natural gas from the same reservoir. Due to the combination of inter-well spacing and thick, porous reservoir, any evidence of this potential enhanced recovery effect is expected to take approximately ~3-5 years to reveal itself, if ever.

The Wabamun A reservoir that this project employs to sequester acid gas is large enough to accommodate injection of acid gases (H_2S and/or CO_2) beyond what is forecasted to occur. As such, this facility/reservoir combination can theoretically be leveraged further to sequester gases from other sources. As operator and majority owner of this facility, TAQA plans to evaluate any and all future opportunity related to this.

Communications Plan

With respect to a communications plan TAQA intends to offer the following and will continue to seek out further opportunities and vehicles for communication of this project:

- TAQA maintained a website during the project, which remains active today (www.crossfieldagi.com). This website was intended to provide technical information and a communications link to industry and the public leading up to, and during the project execution.
- As a condition of the Alberta Energy Regulator's (AER) approval for this AGI scheme, TAQA is required to submit annually a detailed progress report for the scheme which will include data and discussion on performance.
- TAQA intends to publish a technical paper with the Society of Petroleum Engineers (SPE) on the design and performance of the AGI enhanced recovery scheme, subject to any evidence of enhanced recovery revealing itself. TAQA views this as something that would occur ~3-5 years from now pending supporting operational data.

- TAQA has already begun sharing operational experience with other Alberta operators that are considering acid gas injection for their facilities. Although informal and ad-hoc in nature, this is valuable knowledge sharing that TAQA will continue to support.
- TAQA will engage with the Natural Gas Innovation Fund (NGIF) on a prospective roundtable discussion, or other collaborative approach, to share our learnings from this project with other sour natural gas plant operators.

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