York University – On Site Production and Use of Hydrogen

CEM Engineering

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Martin Lensink, Amyaz Jadhakhan, Seyma Basturk, Jaden Murphy, Isaac Moore

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1. Executive Summary

1. The first nom. 5 MWe Gas Turbine Generator (GTG)/CHP was installed in 1997.
2. The second, almost identical, nom. five (5) MWe GTG was installed in 2002.
3. Over the past five (5) years, each GTG has operated roughly 8,000 hrs/year.
4. The operation of the GTGs going forward is under considerable review by York University.
5. Specifically, should the GTGs be utilized for load management only as a CO2 Reduction Strategy?
6. Over the past five (5) years, roughly 60-70 percent (TBC) of the annual power required by the York Keele campus is made by the two (2) GTGs versus 30-40 percent (TBC) purchased from Toronto Hydro.
7. The CO_2 attributable to "fuel is chargeable to power" (FCP) is roughly 15,000 tonnes/year.

1.1 How Can CO_2 Attributable to Power Generation be Reduced?

1. CEM completed a preliminary feasibility study in January of 2024 on burning hydrogen in major equipment. Now operational in the existing central utility building, specifically:
    - The two (2) GTGs
    - The two (2) duct burners between the GTGs and the HRSGs
    - Two (2) older water tube boilers (one (1) B&W, and one (1) Foster Wheeler).
    - One (1) relatively newer water tube boiler made by Groupe Simoneau.
2. The objective of this study is to determine if burning Hydrogen (H_2) in the existing GTGs could have multiple benefits, specifically:
    - Could they reduce congestion in this part of North York?
    - Could the GTGs be used to make efficient power when the gas plants would otherwise be operational?
    - Are there system benefits to the IESO and can these be quantified?
    - Are there benefits to York University in terms of their CO_2 Reduction Road Map?
    - Are there benefits to Enbridge for supplying H_2 mixed with natural gas where the H_2 generation is on site via Electrolyzer?

2. Conclusions

1. IF:

   - Two (2) existing GTGs rated at 5 MW_e each, are now operating at 200 hrs/ year (20 starts/year at 10 hours runtime each start);
   - Both are retrofitted to burn up to 50% H_2 by volume;
   - Enbridge Gas Distribution makes H_2 on weekends and at night on-site via an Electrolyzer;
   - This H_2 is stored on-site for use during weekdays;
   - The H_2 is blended with natural gas at the existing York University Keele Campus Metering and Regulation station;
   - No new house piping is needed because the existing piping can handle the 50/50 H_2/natural gas blend;
   - The IESO offers a 20-year contract for both green capacity and green energy;
   - The GTGs run roughly 4,000 hours per year (5 days a week, 16 hours a day and 50 weeks a year), while the existing roughly 20 natural gas Peaker Plants would be running as well;
   - The Electrolyzer is air-cooled so the need for new incremental water use is very low and;
   - York University enters a long-term contract with Enbridge for the generation and supply of H_2 on-site.

2. THEN:

   - York University can commit to supplying 10 MW_e of green capacity to the IESO-administered grid.
   - Similarly, they can commit to providing 40 GW.h/year of green energy.
   - This project will save ~15,000 tonnes/year of CO_2, which would otherwise have been emitted/released by gas plants.
   - The monthly revenue requirement over the 20-year contract is roughly ~$1,500,000 per month per GTG. This is roughly 80 cents per kW.h and covers both CAPEX and OPEX. This system could also participate in and commit to the 10N "(10-minute non-spinning reserve)"
   - * Provided all "IF" conditions are met.

3. Burning Hydrogen in Existing GTGs

1. Two (2) Solar Turbines nom. 5 MWe Taurus 60 GTGs are currently operating at York University's Central Utility Building (CUB).
2. Upon working in conjunction with the OEM Hydrogen Subject Matter Expert (SME) the maximum hydrogen flow rate is determined to be a 50% H2 blend with natural gas.
3. The following modifications (see Table 1) must be made to ensure the GTGs can burn a maximum of 50% hydrogen by volume with natural gas, in accordance with Solar Specifications.
4. Altering the fuel of combustion from natural gas to hydrogen will have negligible impacts to the combustion dynamics of the machines; any changes will be addressed the hardware and combustion tuning by the OEM.
5. Altering the fuel of combustion from natural gas to hydrogen will have minimal impacts in the anticipated life of the units. Some modifications are expected in overhaul intervals to accommodate maintenance requirements of new hardware.

Table 1 | GTG Modifications for H2 Combustion up to 20% H2 by Volume

									Estimated Price Range ($000s)		Current Engine Hours
Site	**Package**	**Asset Name**	**Engine**	**Package Fuel**	**Control Systems**	**Bleed Valve & Guide Vane**	**Fire & Gas Detection**	**Start System**	**FROM**	**TO**	**30k hr TBO**
North York	TG97216	Unit #1	Overhaul	Major Upgrade	Suitable	Suitable	Suitable	Suitable	$150	$248	12,054 hr
North York	TG02731	Unit #1	Overhaul	Replace	Suitable	Replace	Replace	Suitable	$609	$775	20,740 hr

6. Early indications suggest that the increased flame speed and accelerated combustion as a result of burning hydrogen will allow for quick start benefits. However, further testing is necessary to confirm.
7. What needs to be done to start the GTG quicker with or without H_2 blending?
8. The start time of each 5 MW_e GTG at York University is now 20 minutes.
9. However, the OEM has confirmed that it is technically feasible, with TSSA support, to get the start time under 10 minutes. In fact, they are ascribing 100% certainty to this statement.
10. By starting up quicker as in under 10 minutes, York University could participate in IESO's "10N" (10-minute non-spinning reserve).
11. Additional engineering and due diligence are required to ensure the HRSG hardware is suitable for exhaust from a hydrogen – fueled GTG.
12. Having said that, each HRSG is equipped with a purge fan which is anticipated to be sufficient to ensure the HRSG operates as expected.
13. TSSA requires five (5) complete air changes, including the entire stack volume before ignition can commence.

14. We understand that to get under ten-minute start time, the purge crank cycle would have to take place AFTER the last shut down. Another block and bleed valve assembly would have to be added to each fuel train.

15. Making the required changes and getting TSSA approval, is a standalone project and is not simply a matter of pressing a button. Costs associated with this work is negligible in the overall project costs; however, work is required to navigate the changes with the TSSA and the timeline to complete this is unknown.

16. However, there is precedent that the required changes can be made and TSSA will approve them. The precedent is a 15 MW_e GTG which participates actively in the 10N market, and at which all the required changes were made to achieve 10 minutes.

3.1 Engine Fired Hours at York University CUB

1. Data from Solar Turbines was retrieved and analysed for their operating hours. COGEN #1 operated for ~5,000 hours in 2022. A combination of shutdowns was observed between March 2022 and August 2022 as shown in the chart below. This was mainly attributed to supporting Toronto Hydro repairs coupled with York's semi-annual maintenance with Solar Turbines.

Figure 1 | Engine Fired Hours

2. While this report acknowledges that campus demands changes, the full operational output is assumed to be 4,000 hours per year (16 hours per day x 5 days a week x 50 weeks a year).

3. The data available for Cogen 1 and Cogen 2 is insufficient to granularize either the cause of the outages nor the mode of operation of the GTGs (i.e. planned outage, unplanned outage, ramping or load following). The statements made in **Section 3.1** part (1) were derived from meetings with York operations team.

3.2 How Much Hydrogen is Required?

1. Assuming a 50% hydrogen blend in the fuel mixture, the flow rate of hydrogen was calculated as follows (See **Appendix A** for full table):

Table 2 | Calculating Hydrogen Requirements

	Scenario 1	Scenario 2	
	Summer 30°C Ambient Air	Winter -15°C Ambient Air	Unit
Assumptions			
Number of Gas Turbine Generators	2	2	#
Power required at 1 x Generator	5[1]	6.5[2]	MWe
Natural gas flowrate for 1x GTG	1270[1]	1490[2]	kg/h
Natural gas pressure	1680[1]	1680[1]	kPa(g)
Natural gas temperature	19[1]	19[1]	°C
LHV of natural gas	49	49	MJ/kg
LHV of Hydrogen	120	120	MJ/kg
Calculated Actual System Efficiency			
Efficiency (HHV)	26%	29%	HHV
Efficiency (LHV)	29%	32%	LHV
Properties of New Fuel (50% H_2)			
Hydrogen blend % by volume	50.0%	50.0%	%
Hydrogen % by mass	10.7%	10.7%	%
Weighted average heating value (HHV)	63.8	63.8	MJ/kg
Weighted average heating value (LHV)	56.6	56.6	MJ/kg
Density of fuel mixture (at set conditions)	6.9	6.9	kg/m3
H_2 Requirements			
Flowrate of fuel mixture required in 1 x GTG	1099	1290	kg/h
Total Flowrate of fuel mixture required (2 x GTGs)	2199	2580	kg/h
Total flowrate of H_2 required	236	276	kg/h

[1] Values as observed on site

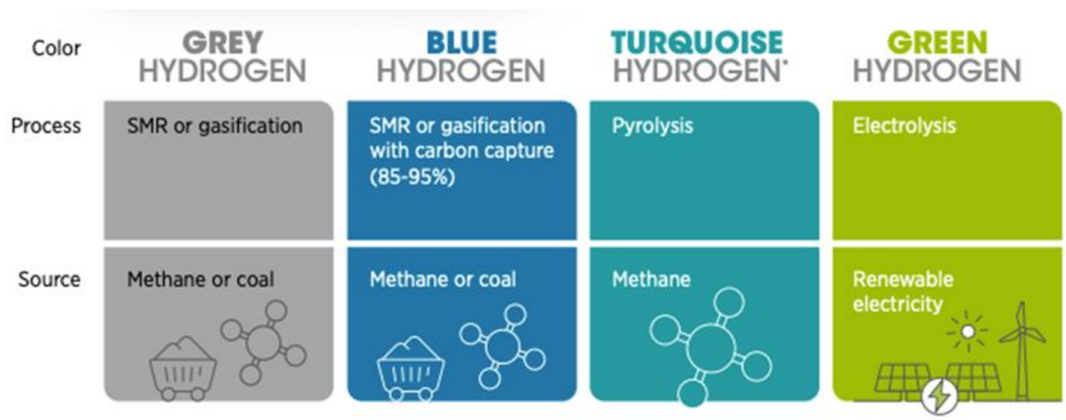
[2] Values as generated on the Solar Turbine simulation program for winter conditions.

2. Interestingly, as shown in **Table 2**, mixing hydrogen with natural gas increases the overall heating value of the mixture. However, the density of the mixture is lower (almost half) than pure natural gas, and in this respect, the energy density (by volume) is expected to be lower. The new volumetric flowrate if the fuel mixture can be expected to be higher to achieve the same energy per unit time into the GTGs. Further investigation into the velocity of the mixture is conducted in **Section 5.2**.

3.3 CO_2 Considerations

1. Hydrogen, when burned, produces water vapor instead of carbon dioxide (CO_2). Natural gas primarily consists of methane (CH_4), which when burned, produces CO_2 and water. Therefore, the more hydrogen is blended into the natural gas, the less CO_2 is produced per unit of energy generated.
2. For every MMBtu of natural gas displaced by burning one MMBtu of hydrogen, ~53 kg of CO_2 is not emitted.
3. Hydrogen has a high energy content per unit mass (about 3 times higher than natural gas). Therefore, a fuel mixture with hydrogen can produce the same amount of energy with less carbon dioxide emissions compared to burning pure natural gas, provided that the fuel is under relatively high pressure, thus achieving a higher energy density per unit volume.
4. However, generating Hydrogen by means of electrolysis requires considerable amount of electricity. To produce "Green" hydrogen, the use of renewable energy sources is required.

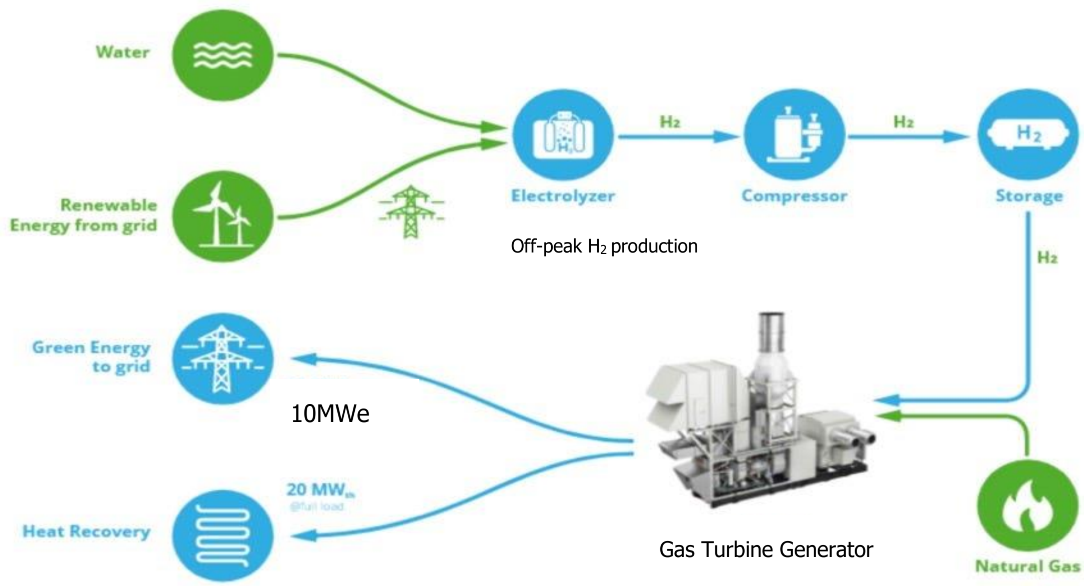
Figure 2 | Colours of Hydrogen (Categorized by production method)



Note: SMR = steam methane reforming.
** Turquoise hydrogen is an emerging decarbonisation option.*

5. Generating hydrogen during off-peak hours, when electricity demand is low and Gas plants are not contributing to the grid, while renewable energy is often more abundant, helps balance the grid. Storing this hydrogen allows it to be used during peak demand times.

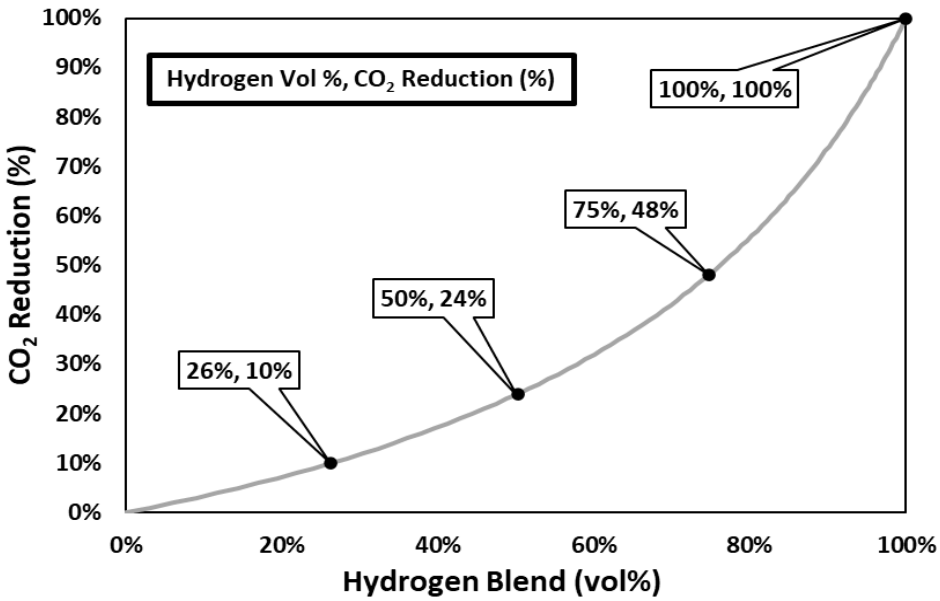
Figure 3 |High-Level block Diagram of H2 production and Electricity Generation at York



6. The natural gas to be displaced when blending hydrogen into the fuel lines at York University amounts to ~2,500 Tonnes per year. This is equivalent to ~**8,200 Tonnes of CO_2 emissions saved**, with the following assumptions.
    a. A 50-50 homogenous mixture (by volume) of Hydrogen and Natural gas in the fuel lines to the GTGs.
    b. The operating fuel gas pressure and temperature remain unchanged.
    c. The GTGs are running for ~4,000 hours per year on the new fuel mixture and generating ~5 MWe each.
7. Emissions due to combustion of fuel mixture: The total emissions by burning the new fuel mixture can be estimated at ~**28,000 Tonnes CO_2 per year**, assuming operation at full capacity for 4,000 hours.
8. Emissions due to production of H_2: The GHG intensity of Ontario's electricity grid is ~35 g CO_2e/kWh electricity generated. Electrolysers have a typical specific electricity consumption of ~57 kWh/kg of H_2 produced (See **Appendix F**). Assuming a hydrogen requirement of 256 kg/h at full capacity for 4,000 hours (See **Table 2**), the emissions allocated to the production of H_2 can be estimated at **~2,000 Tonnes CO_2 per year.** Combined with the emissions from combustion, the total amounts to **~30,000 Tonnes CO_2 per year,**
9. Emissions due to production of H_2 considering MEF: In addition, if marginal gas units are dispatched to meet the needs of the electrolyzer load, the emission factor can be projected at 320 g CO_2e/kWh. This will amount to **~18,700 Tonnes CO_2 per year** for the same amount of hydrogen. On top of the emissions by combustion, the total emissions can be summed up to **46,700 Tonnes CO_2 per year.**
10. Emissions due to combustion of Natural gas: Currently, the combustion of natural gas in 2 x GTGs accounts for **~36,200 Tonnes CO_2 per year** if operated at full capacity for 4,000 hours.

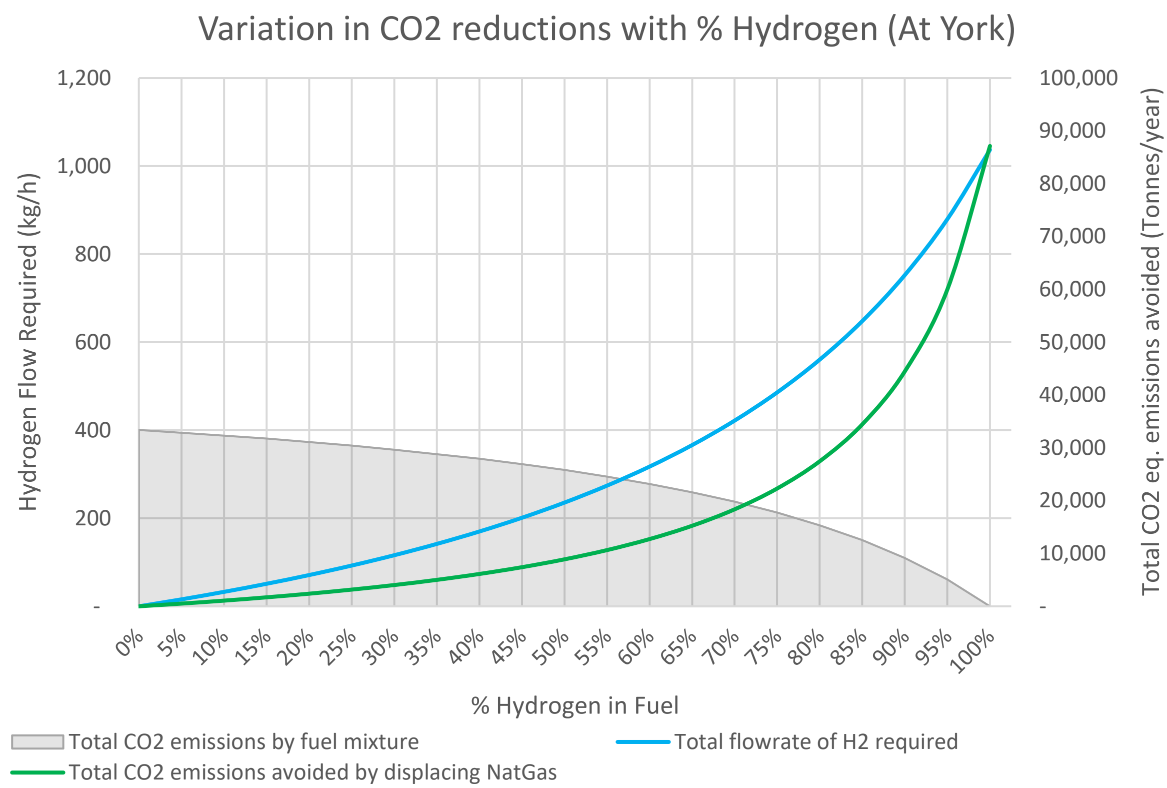
11. If a grid emission intensity of more than 140 g CO_2e/kWh is available, the total combined emissions of producing H_2 and burning the fuel mixture would exceed 36,200 Tonnes CO_2 per year. In this case, we may as well burn natural gas directly into the GTGs.
12. Due to the difference in physical properties of hydrogen and natural gas, the CO_2 reduction potential of burning hydrogen blends is not a linear relationship. The following chart depicts the relationship between the CO_2 emissions and amount of Hydrogen in the fuel.

Figure 4 |Generic relationship between CO2 reduction and Hydrogen blend in fuel



13. The following chart shows the variation of H_2 requirements, and the CO_2 saved by not burning Natural Gas at York University, with respect to the amount of hydrogen in the fuel.

Figure 5 | Variation of CO2 Reductions with % Hydrogen (at York)

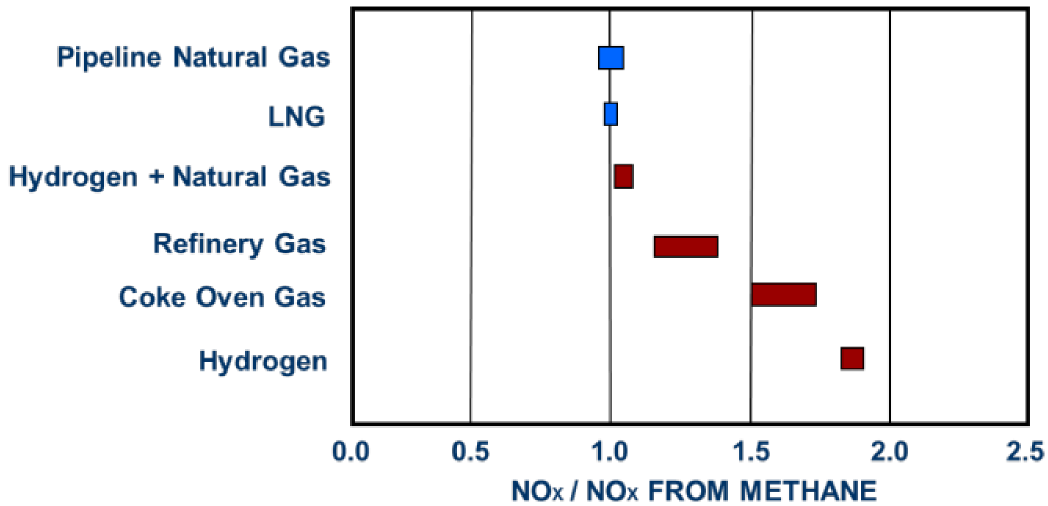


3.4 Emissions of NO_x

1. When natural gas is burned, it produces energy along with carbon dioxide and water as primary byproducts. However, in the high-temperature environment of combustion, nitrogen from the air (which is about 78%) can react with oxygen to form nitrogen oxides (NO_x).
2. NO_x contributes to the formation of acid rain, which can damage ecosystems, forests, and water bodies. It plays a role in the atmospheric reactions that produce ozone, a greenhouse gas that contributes to global warming.
3. Due to their environmental and health impacts, NO_x emissions are regulated by environmental agencies worldwide. Guideline A-5 outlines NO_x emission limits for combustion turbine systems in the province of Ontario. For the each of the two (2) Taurus 60 Turbines at York, the NO_x emission limit is 34 ppmv @ 15% O_2.
4. As flame speed and combustion temperature increase, such as the case with Hydrogen, NO_x emissions increase as well. There are several reduction techniques can be employed, some during combustion, and others post-combustion.
5. Combustion techniques include lean combustion, flame staging and water injection. Post-combustion techniques include Selective Catalytic Reduction (SCR), Lean NO_x Traps (LNT) and Exhaust Gas Recirculation (EGR).
6. CEM Engineering has previous experience with these techniques and is confident applying them in accordance with Guideline A-5.

7. Various literature such as GTEN have provided estimates on NO_x emissions. The following chart compares NO_x produced from the combustion of hydrogen rich fuels with NO_x produced from the combustion of high methane natural gas. This graph has only been validated for use up to 20% H_2. At this time more detailed models must be created to accurately determine NO_x emissions. See **Appendix D** for full report.

Figure 6 | NOx emissions from various fuel sources compared to NOx from methane



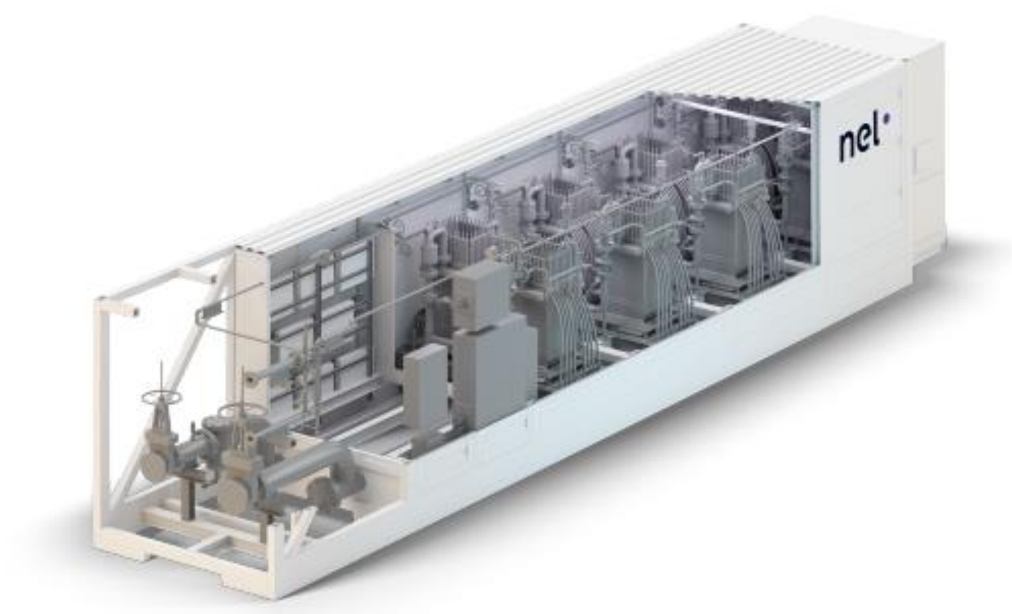
8. Without the use of NO_x reduction, we expect to exceed these emission limits. Currently, York University operates a $SoLoNO_x$ system to reduce emissions. Using 100% natural gas, NO_x emissions are in the range of 15ppmv. Solar Turbines has noted that the $SoLoNO_x$ system is not compatible with levels of Hydrogen above 20%. Due to this, some form of alternate NO_x reduction technology must be employed.

4. Onsite Generation of Hydrogen

1. Electrolyzer systems enable gas turbine power generation facilities to produce hydrogen on-site, blend it with natural gas, and use it as a low-carbon fuel. This approach enhances the sustainability of power generation by GTGs.
2. Electrolyzers are devices that use electricity to split water into hydrogen and oxygen. This method is called electrolysis. The general setup involves several sub-systems, including but not limited to the following:
   a. Feed water purification
   b. Water split using fuel cell stacks (PEM or Alkaline technologies)
   c. Grid power supply to energize the cell stacks
   d. Hydrogen gas purification and cooling
   e. Hydrogen gas storage

   Some Electrolyzer brochures are provided in **Appendix F.**
3. Once hydrogen gas is produced to acceptable specifications, it is stored in onsite storage. Before entering the gas turbine, hydrogen is blended according to the required amount with Natural gas and injected into the existing fuel lines to the GTGs .

Figure 7 | Example of a hydrogen electrolyzer skid from Nel



4.1 Hydrogen Electrolyzer Utility Requirements

4.1.1 Water

1. Ultra-pure water is required for hydrogen production through electrolysis. The water quality is of extreme importance in an Electrolyzer.

2. A water treatment plant is required to achieve the water quality; this plant typically includes pretreatment (to remove organic matter, disinfect and remove suspended solids), reverse osmosis (to remove dissolved solids, salts, metal ions) and polishing (to deionize the water).

3. Previous projects have fulfilled this water quality requirement via a dedicated demineralization system, while some established OEMs can provide an all-inclusive package comprising of a water purification system alongside their Electrolyzer. These systems are tailored to condition city water and achieve the required specification for electrolysis.

4. Current technologies require approximately 9 L of treated water per kg of hydrogen produced. The actual water input requirement for a hydrogen installation is ~19 L of potable water per kg of hydrogen produced. This is the total volume required for the operation of the system.

5. **Table 3** shows a typical water requirement for an Electrolyzer (ASTM Type I); actual water requirements may differ slightly based on specific Original Equipment Manufacturer (OEM) specifications.

Table 3 | Water Requirements for a Typical Electrolyzer

Parameter	Value	Unit
Maximum Electrical Conductivity	0.056	µS/cm @ 25 °C
Minimum Electrical Resistivity	18.2	M'Ω-cm @ 25 °C
pH @ 25 °C	-	-
TOC Maximum	10	µg/L
Sodium Maximum	1	µg/L
Silica Maximum	3	µg/L
Chlorine Maximum	1	µg/L

4.1.2 Electricity

1. Electrolysers require a significant energy input to produce hydrogen. Based on previous vendors' data, a typical 2.5 MW_e Electrolyzer can generate ~500 Nm^3/hr of hydrogen.

2. An adequate electrical connection is required, at a specific voltage, for hydrogen production. Typically, such systems require a 480VAC to operate the cell stacks and other auxiliary devices such as pumps, gas dryers and gas compressors. This may vary depending on the vendors' equipment or what is available on site.

3. In addition, a low voltage 24VDC is also required for the control system.

4.1.3 Cooling

1. Up to ~20kW$_t$ of primary (i.e., Electrolyzer and rectifier only) cooling is required per kg of hydrogen produced.
2. Furthermore, another ~1kW$_t$ of secondary (i.e., hydrogen purification and balance of plant equipment, such as compressors) cooling may be required per kg of hydrogen produced.
3. The cooling requirements can be met via various mediums depending on site and installation parameters (water, air, glycol, etc.).

4.1.4 Gas Blending Overview (Hydrogen & Natural Gas)

1. Gas blending systems are used to mix different gases in precise ratios to achieve desired compositions. These systems are crucial in various industrial applications, including chemical manufacturing, energy production, and gas turbine operations. When it comes to blending natural gas with hydrogen, gas blending systems ensure a consistent and controlled mixture to optimize performance and safety.
2. A typical gas blending station comprises of multiple mixing valves, pressure regulators, control systems, flow meters and sensors. The system ensures that the target ratio between the gasses is achieved.

Figure 8 | Example of a Gas blending station

3. The required flow rate of hydrogen into the existing fuel gas lines amounts to ~250 kg/hr, as mentioned in **Section 3.2**, with the following assumptions:
    a. 50% Hydrogen mixture with Natural gas by volume
    b. Fuel gas pressure ~275psi

c. Fuel gas temperature ~ 18°C

d. Nominal power output~5MWe at each generator terminal

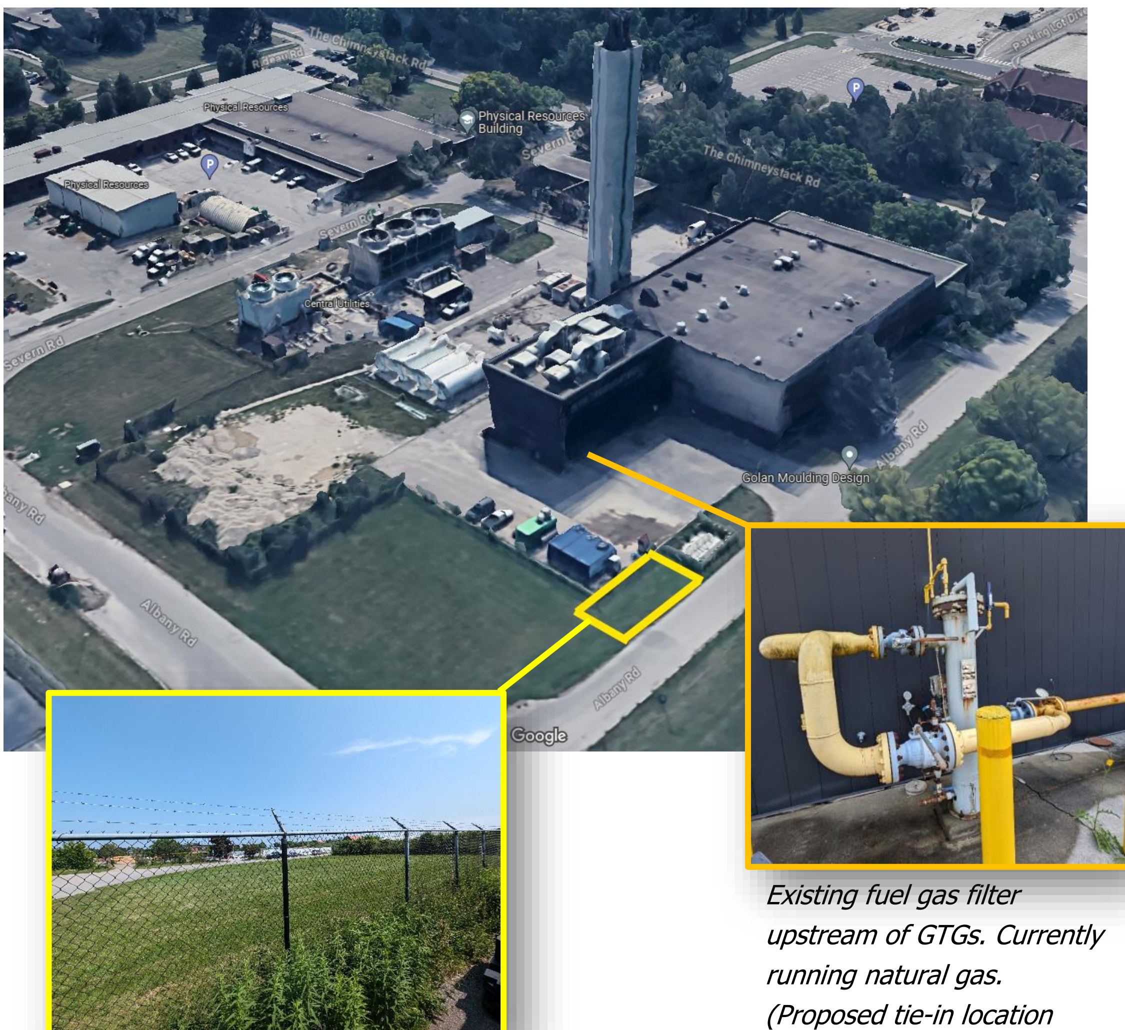
This is equivalent to ~3,000 Nm^3/hr of Hydrogen

4. The hydrogen storage should be sized according to the capacity of the Electrolyzer on site and the rate at which hydrogen must be delivered to the GTGs, while considering the hydrogen production timings and power generation timings.

4.2 Site Implementation Suggestions

1. The following suggestions were made following a site visit at York University Keele Campus.

Figure 9 | York University Keele Campus proposed tie-in point and Electrolyzer location



Existing fuel gas filter upstream of GTGs. Currently running natural gas. (Proposed tie-in location after gas blending)

Available space for Electrolyzer system and blending station

5. Piping Considerations

5.1 Background of Hydrogen Embrittlement

1. Handling hydrogen in an industrial facility involves specific piping considerations due to hydrogen's unique properties. It can cause certain metals to become brittle, leading to cracking and failure. Materials resistant to hydrogen embrittlement, such as austenitic stainless steels are typically used.

2. As steel strength increases, its fracture toughness decreases, raising the risk of fractures due to hydrogen embrittlement. Generally, steel with an ultimate tensile strength below 1000 MPa (~145,000 psi) or a hardness below HRC 32 on the Rockwell Hardness Scale is not considered prone to hydrogen embrittlement.

3. Some of the materials that are known to be particularly susceptible to hydrogen embrittlement include:

    a. High-strength steels, especially those with high levels of carbon or alloying elements like chromium, nickel, or molybdenum

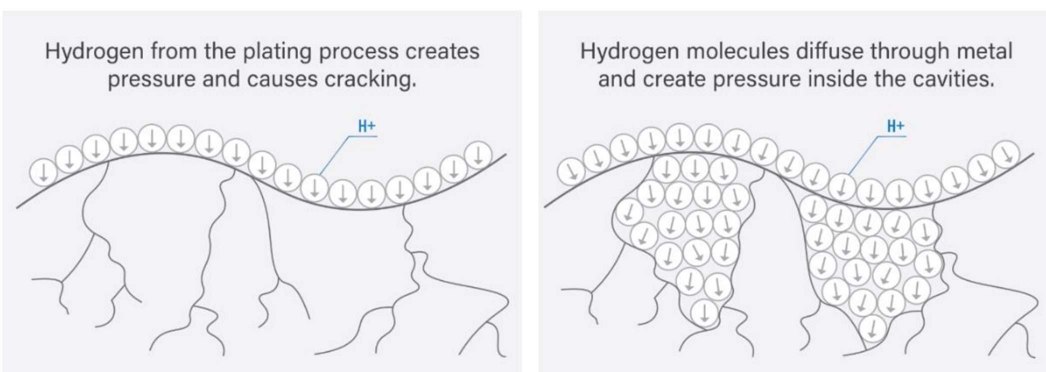
    b. Martensitic stainless steel

    c. Titanium and titanium alloys

    d. Aluminum alloys, especially those with high levels of copper

    e. Some high-strength nickel alloys

Figure 10 | Illustration of hydrogen embrittlement



4. Hydrogen molecules are very small and can permeate through many materials. Due to the high diffusivity and potential for leaks. The higher the pressure, the more vulnerable the pipe is to embrittlement.

5. Temperature fluctuations can cause rapid pressure changes in hydrogen systems. Hydrogen gas expands significantly with temperature increases, leading to higher pressure if contained within a fixed volume. A temperature gradient monitoring system is essential in ensuring that the gas does not undergo excessive thermal expansion.

5.2 Existing Site Configuration & Code Compliance

1. The current piping configuration on site was engineered by Solar Turbines, and the engineering drawings were analysed for their piping specifications.
2. The fuels lines to the GTGs were specified as A10 (ASTM A106 Grade B, see **Appendix B**), with diameters ranging from 2.5 inches to 6 inches. And the current fuel used is Natural Gas, at 275 psi(g) and 19 °C.
3. ASME B31.12 provides comprehensive guidelines and standards for the safe and effective design, construction, operation, and maintenance of hydrogen piping and pipeline systems. **ASTM A106 Grade B is listed among the materials suitable for both industrial piping and pipelines, provided the design pressure does not exceed 6,000 psi(g).** It is hence acceptable to use the existing fuel transmission pipes for 50% hydrogen mixture by volume.
4. However, a thorough analysis of all in-line ancillaries (valves, regulators, flowmeters, and transmitters, among others) must be conducted to determine whether they are compatible with hydrogen in the fuel line.
5. The existing fuel line feeding the GTGs appeared to be 2 inches at its tightest point, upstream of the GTG. At this point, considering actual natural gas conditions on site, the velocity of fuel is estimated at ~13 m/s, which is within the lower range of standard engineering practice.
6. Hydrogen gas contains a lower level of energy per unit volume than natural gas. With 50% hydrogen in the fuel mixture, the flowrate was adjusted in a simulation to match the correct heating value, and the considering the new density of the mixture, the gas velocity was calculated to be ~23 m/s.
7. Standard engineering practice recommends natural gas velocity in pipe to range from 15 to 30 m/s. While engineering practices are not yet established for hydrogen flows, ASME B31.12 recommends staying below the erosion velocity, which can be calculated to be ~75 m/s at 400 psi(a).
8. It is thus safe to say that the velocity if the new fuel mixture is within the acceptable range of operation without any detrimental effects.

6. Area Classification Considerations

6.1 Background on Area Classification

1. A classified area is where the risk of explosion might occur due to flammable gases, vapors or liquids, combustible dusts, combustible flyings or fibers. Area classification is crucial for safety as it reduces the risk of fires or explosions and ensures devices used in hazardous locations are safe and suitable.
2. These areas are classified based on either the Division System or the Zone System. In the zone system, the zone is defined based on the frequency of hazardous conditions and their duration. Classes define the general property of the hazardous substance present in the atmosphere, such as flammable gases or vapours, combustible dusts, and combustible flyings or fibers. In this case, the hazardous substance at the site falls into Class 1 because we are dealing with gas (specifically hydrogen and natural gas). The areas are further classified into groups and subgroups that define the type of hazardous substance such as acetylene, hydrogen, metal dusts, and so o.
3. The impact of hydrogen and natural gas blending on the existing system inside the building depends on the methodology used for the original area classification. There will be no changes made to the existing system assuming the current area classification was based on API 505 RP, and assuming no changes will be made to the piping inside the building to accommodate H_2. However, if IEC 60079 was used, there will be changes due to differences in gas composition, resulting in a different classification. This will necessitate a further area classification study.
4. As proposed in **Section 4.3**, the hydrogen blending station skid outside the building will be classified according to the vendors specification which will most likely be classified under Class 1, Zone 2 (or Division 2).
5. A detailed area classification study must be conducted before placing the blending station on site to comply with the codes and standards.

6.2 Codes and Standards Considerations

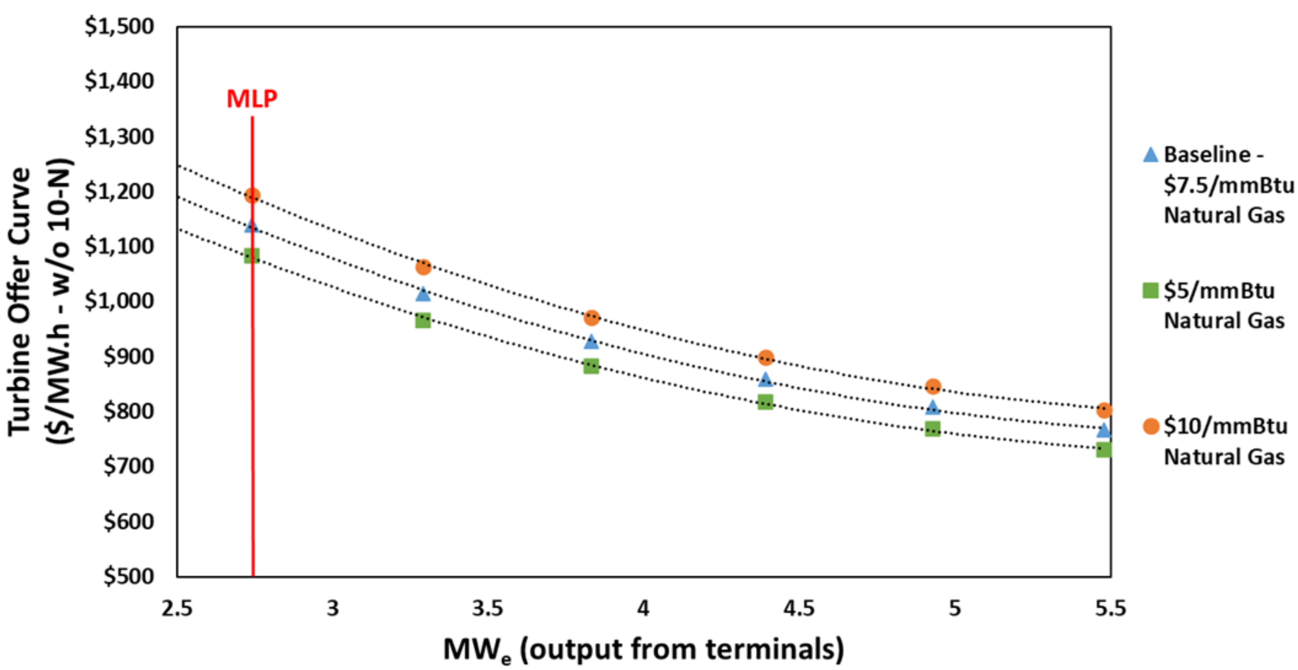
6. Design of piping system must comply with the following Codes and Standards (but not limited to the following Codes and Standards):
    a. ASME B31.12
    b. CAN/BNQ 1784-000-2007 (Canadian Hydrogen Installation Code)
    c. AIGA 087/14
    d. AIGA 087/20
    e. NFPA Electrical Installations in Hazardous Zones
    f. API 505 – Hazardous Area Classification

7. Addressing IESO Priorities

7.1 H_2 Turbine Offer Curve

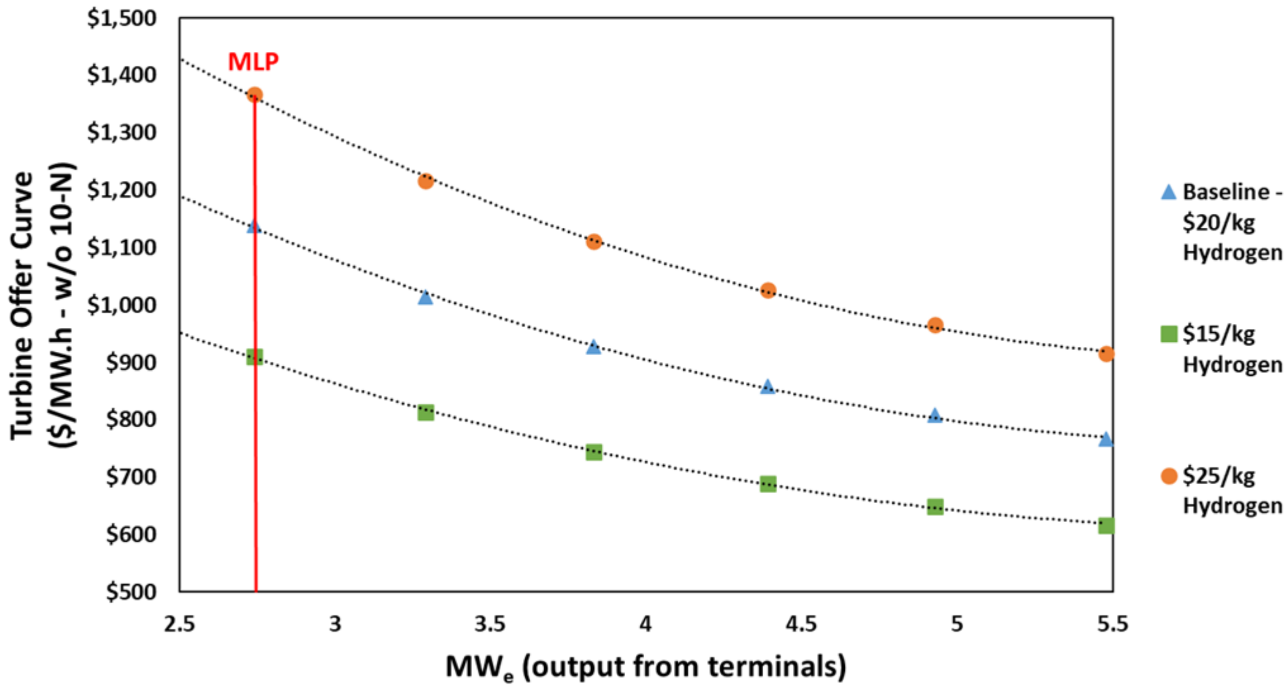
1. The "offer curve" for the proposed retrofit Hydrogen Gas Turbine Generator (GTG) is largely a function of fuel blend cost.
2. The fuel blend cost assumes the following:
   a. Hydrogen is generated during "off-peak" hours and stored on-site
   b. Hydrogen is blended into the existing natural gas piping via a new blending station also located on-site
   c. The price of hydrogen contemplates recovery of capital investment associated with hydrogen generation and storage equipment
3. The below graph demonstrates the "Hydrogen Turbine Offer Curve" for one (1) nominal 5 MW_e Hydrogen GTG combusting a 50% by volume hydrogen fuel blend.
4. The graph demonstrates how variations in the price of Natural Gas impacts the "offer price" when the Price of Hydrogen is fixed at $20 per kg. Note that Minimum Loading Point (MLP) is assumed to be 50% of Maximum Continuous Rating (MCR).

Figure 11 | Turbine offer curve vs MWe output for various price of Natural Gas



5. Furthermore, the below graph demonstrates how the "offer curve" varies as a function of hydrogen fuel price, when the price of natural gas is constant at $7.50/mmBtu.

Figure 12 | Turbine Offer Curve vs MWe output for various price of H2



6. It is clear that the hydrogen "offer curve" is most sensitive to the price of hydrogen fuel, whereas other factors, such as capital investment in retrofits or O&M expenses, have less of an impact on the price at which a hydrogen fueled GTG would offer into the electricity market

7.2 Carbon Tax Parity (H2 vs Natural Gas)?

1. The Carbon Price required to achieve cost parity for a "Hydrogen GTG" versus a conventional Natural Gas GTG is largely a function of the cost of the respective fuel used by the GTG.
2. The Capital Investment, on a "tonne of CO_2e reduced" basis, is much less of a factor in terms of achieving cost parity between the two (2) power generation technologies under a Carbon Price regime, particularly when the cost of equipment upgrades/retrofit is levelized over the lifetime of the asset (i.e., the Levelized Cost of Carbon Abatement (LCCA) over 20-years for the Required Capital Investment is rather immaterial in comparison to the cost of hydrogen fuel).
3. The below table represents the required Carbon Price value to achieve fuel price parity for a 100% hydrogen fuel blend for a retrofit GTG.

Table 4 | Required Carbon Price to Achieve Natural Gas Fuel Price Parity

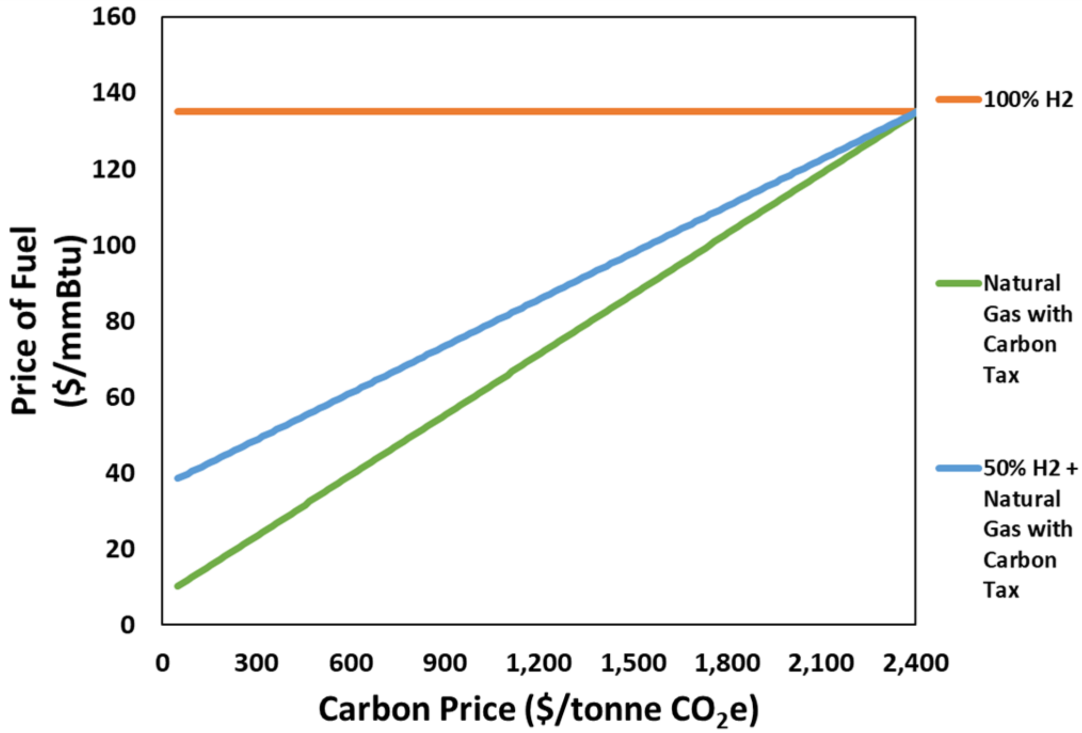
Carbon Price ($/tonne)	Hydrogen Fuel Cost ($/mmBtu)[1]	Natural Gas Costs w/ Carbon Tax ($/mmBtu)[2]
50		*10*
65		*11*
80		*12*
95		*13*
110		*13*
125		*14*
140		*15*
155	*135*	*16*
170		*17*
230		*20*
300		*25*
500		*35*
1,000		*60*
1,500		*90*
2,000		*115*
2,400		*135*

1 Assumes electrolytic hydrogen produced with zero emission intensity electricity (therefore no Carbon Price burden) at a baseline price of $20/kg.

2 Assumes base commodity cost of $7.50/mmBtu Natural Gas delivered to site from DAWN Hub and 0.053 tonnes CO_2e per mmBtu Natural Gas.

4. Furthermore, the below graph demonstrates the price of fuel blends (1. 100% Hydrogen by volume, 2. 50% Hydrogen by volume + 50% Natural Gas by volume, and 3. 100% Natural Gas by volume) as a function of the Carbon Price.

Figure 13 | Price of Fuel Blends vs Carbon Price



7.3 Economic of Retrofitting Existing Turbines to Burn H_2

1. To achieve a 25% by volume blend of hydrogen in the existing GTGs, there is a requirement to upgrade the fuel package, the fire and safety equipment, emissions control and the core turbine itself. It is estimated to cost roughly \$400,000/MW_e to \$500,000/MW_e (+/- 50%) to complete these retrofits for the existing GTGs. These capital investment costs will vary for each GTG and do not include costs associated with the generation, storage, and blending of hydrogen into the existing piping infrastructure.
2. To achieve a 50% by volume blend in the existing GTGs, the same upgrades as required for the 25% blend are required, in addition to further retrofit/upgrade to the core turbine. It is estimated to cost ~\$600,000/MW_e to \$750,000/MW_e (+/- 50%) to complete these retrofits for the existing GTGs. This estimate does not include the upstream hydrogen equipment required and does not include any emission control technology which will in all likelihood be required should the project move forward in the next five (5) years (additional hydrogen GTG retrofit technology is under development to reduce requirements for additional emission control equipment but is not presently available; the costs for this technology is not yet available).
3. A 100% by volume hydrogen blend is technically possible/feasible, however, the cost to retrofit and replace equipment for an existing GTG system may be cost prohibitive. In this scenario, it may be more cost effective to replace the existing GTG with a "hydrogen ready" GTG system (see Appendix C for a project example) for the following reasons:
    a. A 100% by volume hydrogen blend will likely require the addition of emission control technology to meet existing regulatory requirements for criteria air emissions (e.g., NO_X) which may result in reduced equipment performance or increased costs

b. The existing piping infrastructure may be able to handle blends of hydrogen, but it is not evident whether the existing piping infrastructure can handle 100% by volume hydrogen for the next twenty (20) years of operation

c. The retrofit of the existing GTG system for a 100% by volume hydrogen fuel blend may require a level of effort akin to the installation of a new GTG system which is designed specifically to handle blends of hydrogen and natural gas from 0% by volume to 100% by volume

7.4 Dynamics of Grid Scale Turbines Burning H_2

1. Based on the conditioning of the hydrogen fuel in the blending station (e.g., compression and mixing of natural gas and hydrogen) the mechanical performance of the existing GTGs (retrofit to handle the combustion of a 50% hydrogen fuel blend) is not expected to drastically change, provided the flowrates are adjusted to reflect the required energy input in the GTGs, as mentioned in **Section 3.2.**
2. It should be noted, however, that the upfront conditioning of the hydrogen fuel may represent an increased parasitic electrical load, which may decrease total electrical output from the GTG's as a system (i.e., output at the generator terminals is similar, but total system electrical efficiency may decrease if compression equipment is powered Behind-The-Meter (BTM)). Anticipated parasitic electrical load is, at a high-level, roughly 57 kW.h/kg H_2 (OEM and technology dependent).
3. Existing GTGs retrofit to burn blends of hydrogen are not expected to realize a reduced response to grid dynamics**.**

7.5 Technical Feasibility of Retrofitting Existing GTGs to Burn H_2

1. This study has evaluated the technical feasibility to retrofit two (2) existing GTGs to operate with a blended hydrogen fuel.
2. It is technically feasible to retrofit existing GTGs, which presently burn natural gas, to burn a hydrogen/natural gas fuel blend.
3. Depending on the age of equipment, and the type of emission control technology already in place, the retrofit of other existing GTGs in Ontario may be similarly (or even more so) technically feasible in comparison with the GTGs evaluated for this study.
4. In general, the portions of a GTG system which require the most scrutiny, to evaluate whether an existing GTG system can be retrofit to combust some fuel blend containing hydrogen, are the following:
    a. The existing natural gas piping on-site (to determine material compatibility and durability over the lifetime of the GTG system}
    b. The fuel handling system, including any compression equipment located at the GTG System (i.e., not considering upstream compression of the hydrogen fuel blend, which this project features)
    c. All existing electrical equipment which may require replacement or retrofit to ensure compliance with Area Classification guidelines/requirements (such as API 505)

d. The core components of the actual GTG, which may be manufactured with materials incompatible with sustained combustion of fuel blends with high concentrations of hydrogen

5. Furthermore, what is most evident from this study, is that the financial feasibility of this type of retrofit project (retrofit existing GTG to combust a 50% by volume hydrogen fuel blend) is largely driven by the price of the hydrogen fuel.

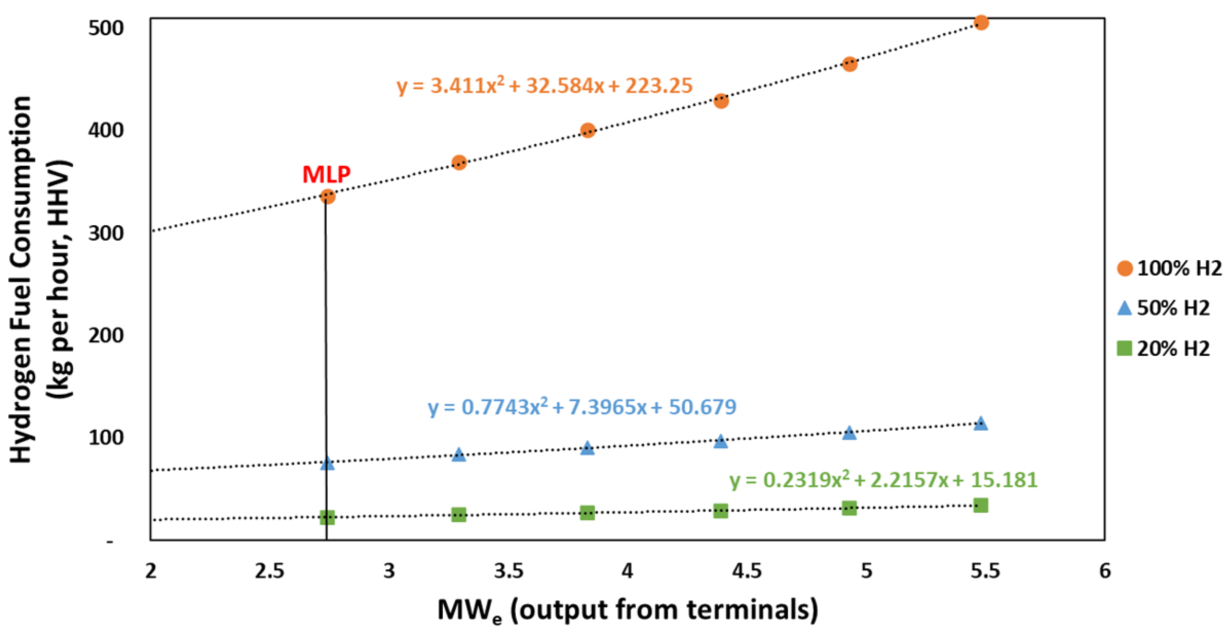
   a. For example, the monthly revenue requirement for such a retrofit project is in the range of ~$1,500,000 per month for each 5 MW_e GTG system

   b. With the retrofit GTGs operating at a nominal 4,000 hours per year (on a 5x16 schedule), this would amount to a price of power of roughly $0.80/kW.h to meet the minimum financial requirement to entice the retrofit of a 5 MW_e GTG to burn a 50% by volume hydrogen fuel blend

7.6 Generation of H2 for Power Generation vs Use

1. The proposed project which is the focus of this study contemplates the operation of two (2) nominal 5 MW_e GTGs retrofit to combust a fuel blend containing 50% hydrogen by volume.
2. To operate both GTGs at 5 MW_e with a 50% by volume hydrogen fuel blend, ~250 kg/hr of hydrogen is required; this GTG operation mode requires hydrogen production equivalent to the operation of a ~**15** MW_e Electrolyzer, operating at night and on weekends when the grid-level natural gas power plants are not operating.
3. If these two (2) same GTGs were to operate with a 100% hydrogen fuel blend, ~1,000 kg/hr of hydrogen would be required to produce 10 MW_e of power (See **Section 3.2** (H)), which would require the operation of a ~**60** MW_e Electrolyzer system at night and on weekends.
4. The following graph demonstrates hydrogen fuel consumption as a function of MW_e output (per GTG) and hydrogen volume blend percentage.

Figure 14 | Hydrogen fuel blend consumption vs MWe output



7.7 Will Electrolytic H_2 Production Result in Decarbonization?

1. This study assumes that the existing GTGs, retrofit to operate with a 50% by volume hydrogen fuel blend, will operate for ~4,000 hours per year, when natural gas fired "peaker" power generation plants in Ontario would be running to meet grid loads.
2. The Electrolyzers would be operating and making hydrogen for the remaining ~4,500 hrs a year when natural gas fired "peaker" power generation plants are not running.
3. For each 5x16 operating week (i.e., 5 days a week for 16 hours), the Electrolyzer system would have to make and store ~4,000 kg of Hydrogen (i.e., ~250 kg/hr for ~8 operating hours per week).
4. This hydrogen would need to be made during the other 88 hours of the week (7 days x 24 hours – 5 days x 16 hours) and stored in multiple hydrogen storage tanks with a nominal capacity of ~4,000 kg Hydrogen per day of operation.
5. The production of hydrogen at nights and on weekends will mitigate the exacerbation of grid level emissions associated with the operation of Natural Gas fired "peaker" power generation plants in Ontario.
6. Alternatively, reducing the runtime of the GTGs to a 5x10 operating schedule (i.e., 5 days a week for 10 hours), would reduce Hydrogen storage requirements to ~2,750 kg of hydrogen per day of operation. This would also reduce the price of hydrogen by ~20% while maintaining the decarbonization potential of this system.

8. Financial Feasibility

8.1 CAPEX to Retrofit GTGs

1. The cost to retrofit the turbo machinery to burn 50% H_2 is roughly $2 million CAD/GTG.
2. This consists of roughly $1 million to "swap out" the core turbine.
3. We have had input from the OEM solar gas turbines out of San Diego on this one $ 1 million estimate.
4. This is an AACE Class 5 cost estimate.
5. Note that the gearbox, generator, and balance of plant equipment around the GTG would all remain the same.
6. The $2 million per turbine/GTG consists not only of the $1 million for the turbine swap from Solar. It also consists of engineering and project management time with installation and commissioning of the equipment.
7. The $2 million per GTG does not include the generation and blending of hydrogen as this is part of the Enbridge estimate.
8. We are implicitly assuming that the repowered retrofitted GTGs will be subject to Ontario Regulation A-5 for GTGs with a 42 ppm NO_x limit.

8.2 Cost of H_2 Supplied by Enbridge (EDG)

1. A very rough cost for Enbridge to supply hydrogen to York University is $20/kg.
2. This is equivalent to roughly $135/mmBtu (HHV).
3. This presumes a system that can deliver up to 4,416 kg/day.
4. Specifically, the plant size consists of six (6) units at 2.5 MW_e each (15 MW_e total).
5. Other assumptions made include the following :
    a. Land is provided by York to Enbridge at no cost
    b. Enbridge will design, build, own, operate, and maintain the system
    c. York will be provided with an all-inclusive unit price which allows Enbridge to recover both fixed and variable costs
    d. An assumption has been made for the cost of electricity, but this will be treated by Enbridge as a flow-through cost
    e. The CAPEX estimate is to AACE Class 5 (+/- 50%)
    f. H_2 production can vary anywhere between 1,000 and 4,416 kg/day
    g. Hydrogen meets SAEJ 2719, Type I, grade L with a hydrogen quality of 99.9995%
    h. Startup time is less than 10 minutes
    i. The unit will be air-cooled to minimize the water required
    j. Storage of liquified hydrogen is included in the estimate
    k. Transformers and electrical construction are included in this "SWAG" estimate.

8.3 Operating Items Assumed

1. For this study and high-level assessment, we have assumed that the two (2) GTGs will operate 5 days a week, 16 hours per day.
2. This is specifically from 7:00 AM to 11:00 PM, Monday to Friday.
3. We are also assuming 50 weeks/year of operation, taking stat holidays which fall on weekdays into account.
4. Therefore, we are assuming a runtime of 4,000 hours/year.
5. The premise of this assumption is that this is when the gas plants would otherwise be running and therefore if we can reduce CO_2 attributable to gas plant operation. Despite this minimal reduction, we are still helping the carbon footprint in Ontario.
6. 'Presently the challenge is that many gas plants are operating at night, in which case the hydrogen made with electricity during this time would not be green at all. Specific dispatch parameters will be required to ensure the project meets its emissions targets.
7. However, as we move towards 2035, we are assuming that the gas plants will not be operating as much at night, in which case, this method/mode of operation is in the public's interest.

8. For clarity, note that once again, we are assuming that the two (2) turbines would not be normally running at York.
9. We are also assuming that if the campus load was below 10 MW_e, which does occur occasionally, there's a possibility that the surplus power could be put on the grid at the Steele's TS.

8.4 Price Required from IESO

1. We estimate the monthly revenue requirement for a retrofit project to enable 50% H_2 firing by volume to be in the range of $1,500,000/month per GTG.
2. This presumes an overhaul cost or roughly $2.0 million – $2.5 million per GTG.
3. It also assumes price for hydrogen from Enbridge around $20/kg.
4. Assumes also 4,000 hours per year of operation.
5. This translates into a price paid for this green peaking power to be in the range of 80 cents per kW.h.
6. Obviously the 15,000 tonnes per year of CO_2 credits belong to the Province, although recent procurements have left environmental attributes with the generator.
7. This does not include potential revenue or credit for participation in the 10N market.
8. The prevailing benefit for 10N participation is roughly $5/$MW_e$ per 10N capacity. If we could offer 10 MW_e of 10N capacity for the other 4,000 hrs/year, when we are not already running, this would be roughly $200,000/year of 10N revenue ($50/hour x 4,000 hr/per of capacity made available).

9. Appendix A – Hydrogen Flowrate Calculation

10. Appendix B – Solar Turbines Piping Specifications

11. Appendix C – Baker Hughes Hydrogen Gas Turbines

12. Appendix D – Hydrogen in Natural Gas Combustion Report

13. Appendix E – CEM Area Classification Guidelines for Natural Gas

14. Appendix F – Electrolyzer OEM Brochures