GAS TURBINES FOR ENERGY NETWORK SYMPOSIUM
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HYDROGEN PRODUCTION AND BLENDING FOR GAS TURBINE

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Abstract

Enbridge Gas and Siemens Energy recently collaborated on a pre-FEED study to assess technical and economic feasibility of producing hydrogen at a gas compression station and blending the hydrogen into the natural gas fuel supply of an aeroderivative DLE gas turbine compressor driver. The hydrogen would be produced by electrolysis, using electricity generated by a turbo-expander which replaces an existing gas pressure regulating valve. Additional energy would be recovered from the gas turbine exhaust and used to preheat the turboexpander inlet flow, thereby increasing the power available to produce hydrogen. The net effect is to reduce carbon dioxide emissions from the site by recovering energy that would otherwise be "lost" (converted to low grade heat) in the existing pressure regulating process and in the gas turbine exhaust.

The study included preliminary design and performance assessment of the integrated hydrogen production and blending system including preliminary sizing of major sub-systems, identification of utility requirements and potential equipment suppliers, estimates of capital expenditures and considerations for estimating operational expenses. A second major theme involved assessment of the effects of hydrogen on the gas turbine performance and life cycle, and identification of equipment changes required to operate the gas turbine with 5% to 40% by volume of hydrogen blended into the natural gas fuel supply.

This paper provides an overview of design and performance challenges for the integrated hydrogen production and blending system, summarizes the effects of hydrogen on aeroderivative DLE gas turbines and provides examples of changes required to operate with up to 40% volume hydrogen.

Compressor Station

The Enbridge Gas compressor station is operating as a critical part of the company's pipeline transmission system. The station was built to enhance the reliability and security of natural gas supplied to millions of customers in a large Canadian metropolitan area. The compressor station consists of two 45,000 hp Siemens Energy centrifugal compressor sets which are driven by Siemens Energy SGT-A35 DLE RT61 gas turbines. The gas turbine packages are supplied with on-skid acoustic enclosures and are themselves located inside compressor buildings which also act as acoustic enclosures. Figure 1 shows an aerial view of the site.

Figure 1. Enbridge compression station

Concept Design and Objectives

Natural gas transmission pipelines operate at high pressure to efficiently transport large quantities of gas over long distances. The gas pressure must be reduced before distributing to end users to ensure safety and compatibility with appliances. The gas compression station under study incorporates a pressure regulating valve to reduce gas pressure. By utilizing a turboexpander instead of a regulating valve, it will be possible to recover energy from the expansion process, energy which is currently being "lost" (energy is conserved during the expansion across the regulating valve but is converted into low temperature heat and is less available to do work).

The temperature of the natural gas reduces as it passes through the pressure regulating valve. To avoid risk of freezing or formation of hydrates after expansion, heat is currently added at the valve outlet using energy supplied by a station boiler. By replacing the valve with a turboexpander, the natural gas temperature will reduce even more, because work is being done where previously it was not. Rather than adding additional heat at the turboexpander outlet, the chosen solution is to preheat the inlet of the turboexpander using waste heat recovered from the gas turbine exhaust. Preheating also increases turboexpander output power. The amount of preheating is constrained by the maximum allowable gas temperatures at inlet and outlet of the turboexpander.

Figure 2 shows a schematic process flow diagram and figure 3 shows a preliminary facility layout. The system was optimized to maximise the production of hydrogen taking account of site and operational constraints. The following systems were in scope:

- Electricity Generator package including the Turboexpander.
- Hydrogen generation package (Electrolysis Facility).
- Hydrogen management with the compression and purification processes.
- Gas Turbine Waste Heat Recovery unit.
- Fuel blending skid for mixing Natural Gas with Hydrogen.
- Cooling water system
- Firefighting system
- Preliminary interconnecting piping routes
- E-house and power generation and distribution system for new equipment
- Automation system (Integrated Control and Safety System – ICSS)
- Utility systems such as nitrogen for purging and compressed air for service and instrumentation.

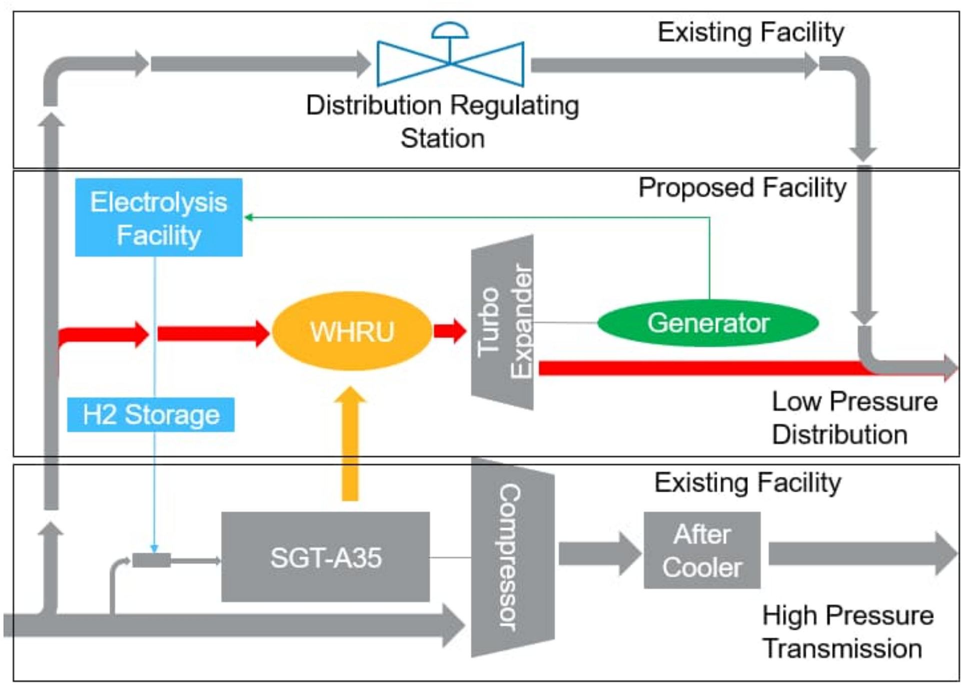

Figure 2. Process Flow Schematic

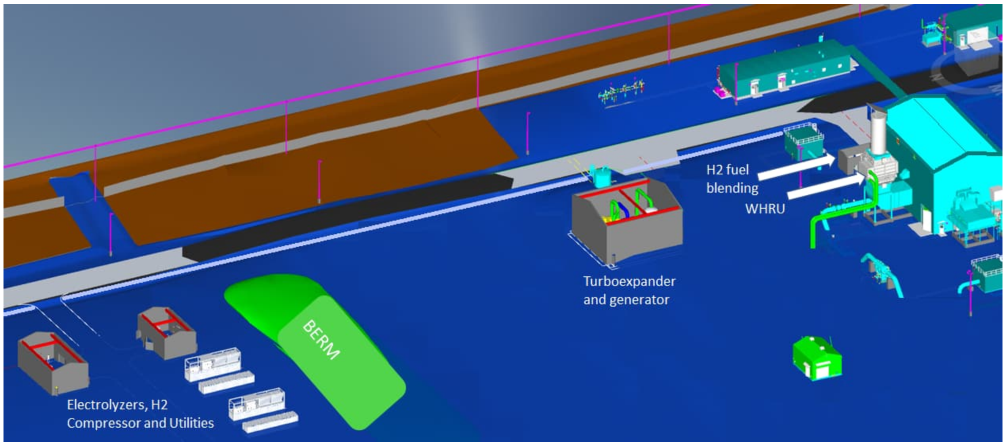

Figure 3. Preliminary Facility Layout

The power output from the turboexpander depends on the flow of gas to the distribution line and the pressure drop between the transmission and distribution lines. Figure 4 shows typical operating conditions including seasonal variations that were considered for calculation of overall system performance.

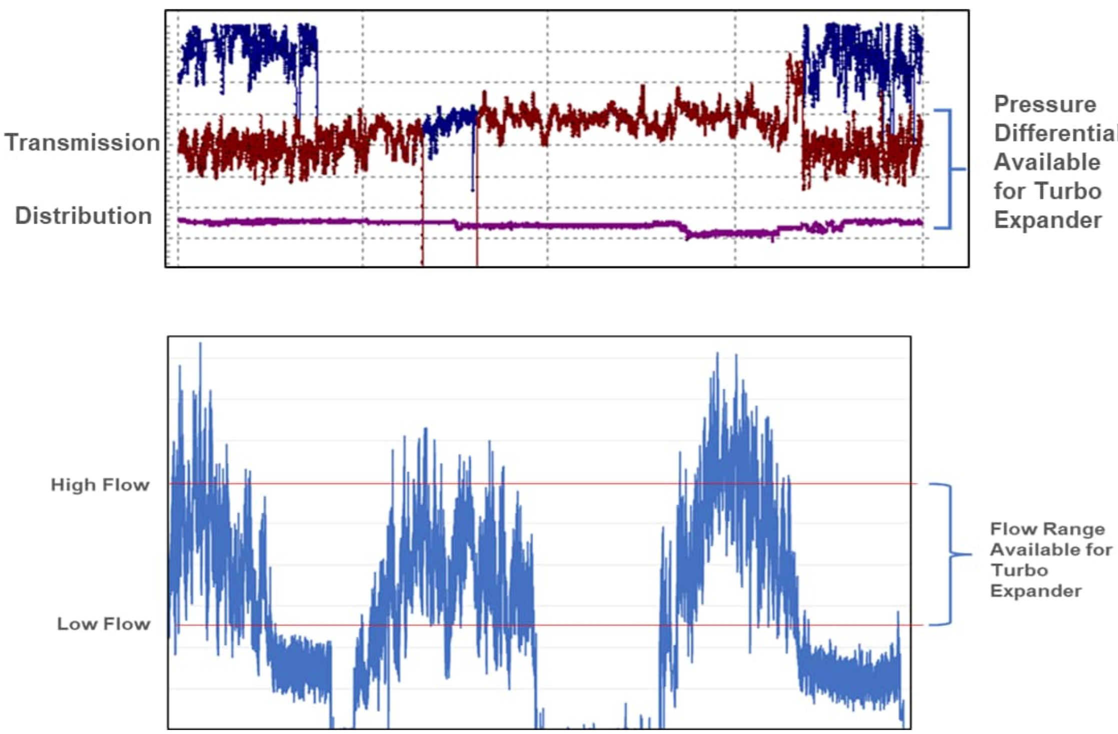

Figure 4. Typical Turbo-Expander Operating Pressure and Flow

The waste heat recovery unit is designed to maximise the energy recovered from the gas turbine exhaust. The trade-off is a small reduction in gas turbine thermal efficiency due to higher exhaust pressure losses.

H2 Production and Emissions Reduction

Production of hydrogen will vary with the flow of natural gas and the pressure drop through the turboexpander, limited by the capacity of the onsite production facility. For effective utilization and emissions reduction, the facility will tend to produce hydrogen at the maximum rate of the day. The percentage volume of hydrogen in the fuel will tend to vary with gas turbine power (figure 5), with greater volumes occurring at lower powers. Figure 6 shows savings in carbon dioxide emissions as a function of hydrogen % volume.

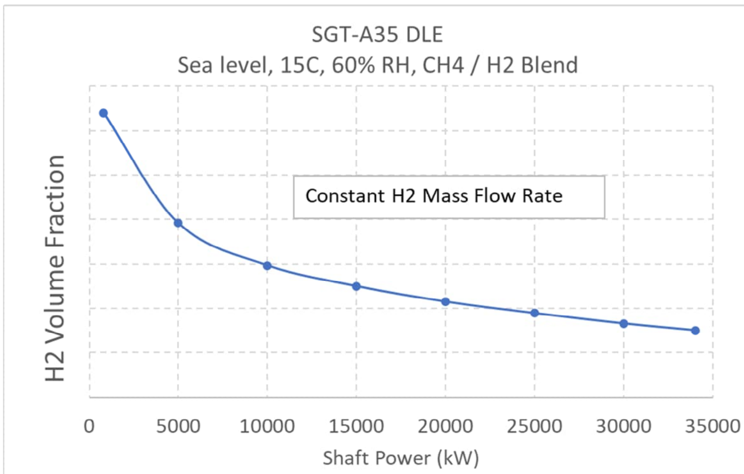

Figure 5. Variation in Hydrogen Blend % Volume with Power

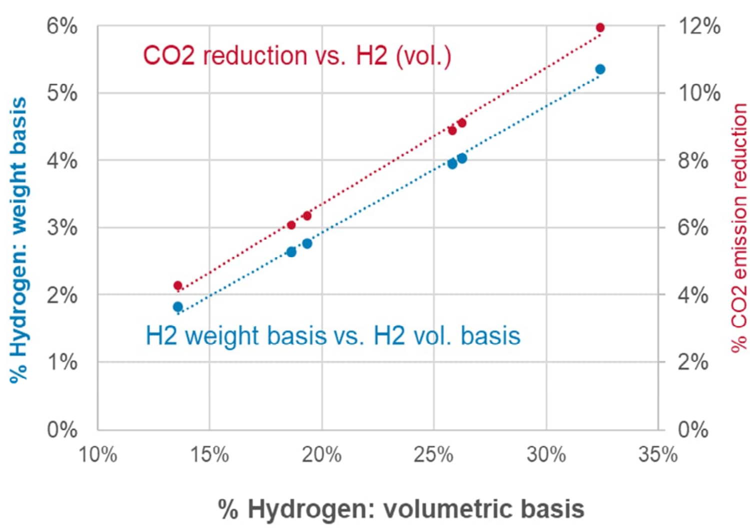

Figure 6. CO2 Reduction versus Hydrogen % Volume

In this scenario of constant hydrogen mass flow rate, it is useful to think of emissions savings in terms of mass flow of hydrogen. The savings in carbon dioxide for each kg of hydrogen blended are easily derived as follows:

- The lower heating value (LHV) of hydrogen on a mass basis is approximately 2.4 times higher than methane (the main constituent of natural gas)
- The mass balanced equation for combustion of methane shows that 16kg of methane produces 44kg of carbon dioxide.
- The net effect is that each kg of hydrogen blended saves approximately 2.4kg of methane and thus 2.4 x 44 / 16 = 6.6kg of carbon dioxide.

This assumes no incremental carbon emissions are required to generate, process and blend hydrogen.

Hydrogen Challenges for Aeroderivative DLE Gas Turbines

Figure 7 shows a summary of current aeroderivative gas turbine hydrogen capability. Siemens Energy aeroderivative gas turbines with conventional non-DLE combustion systems have service experience with fuels containing high levels of hydrogen (up to 85% by volume for legacy products). Water injected non-DLE engines can operate with 100% hydrogen fuel depending on local conditions and requirements, but package solutions to handle very high levels of hydrogen are not yet available as pre-engineered options.

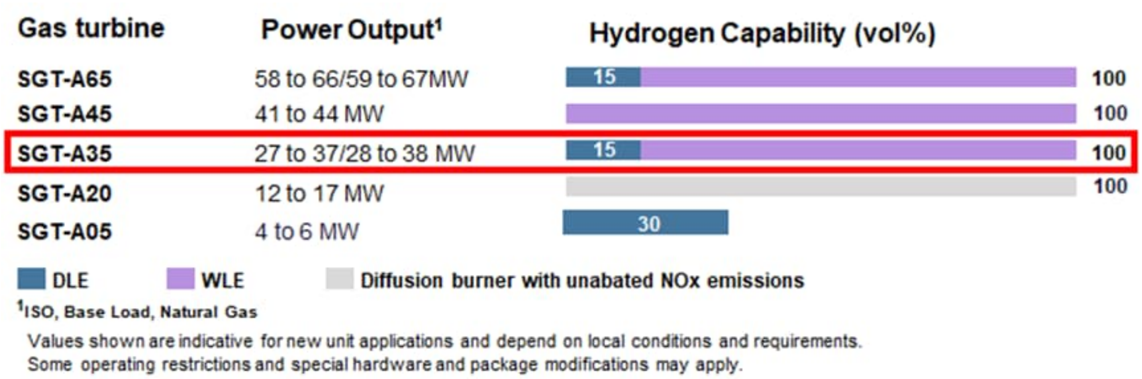

Figure 7. Aeroderivative Gas Turbine Hydrogen Capability

It is readily apparent from figure 7 that current DLE capability is lower than non-DLE. DLE combustor architecture is based around control of flame temperature within specific bands to minimize NOx and CO emissions. The SGT-A35 DLE incorporates a lean burn premix two-stage serial combustion system (primary and secondary zones) for greater flexibility and control of emissions. Zone temperatures are actively controlled by premixing fuel and air prior to entering the combustion chamber. Within the margin between compliant NOx and CO, and ultimately lean blow out, the zone temperatures are optimized to permit stable operation. Fuel maps are usually developed through testing, as current analytical methods do not allow sufficiently accurate predictions of emissions or combustion dynamics without calibration.

Addition of hydrogen to natural gas adds a major challenge for DLE combustion through changes in flame speed and flame dynamics (figure 8). The flames have different reaction chemistry and are shorter, increasing the risk of flashback or flame anchoring. Thermo-acoustic interactions may lead to generation of noise.

Siemens Energy intends to test the current SGT-A35 DLE combustion system to verify capability with hydrogen blends. Testing will explore risks and mitigations associated with staged lean burn premixed combustion in the aeroderivative architecture, including emissions, flashback, flameout, acoustics, flame position, exit temperature profiles and component temperatures. Fuel maps will be updated to ensure stable operation with varying amounts of hydrogen.

Siemens Energy is also developing new combustor technology to be capable of operating with any volume of hydrogen up to 100% with low NOx emissions and without water injection. Figure 9 shows the development roadmap schedule.

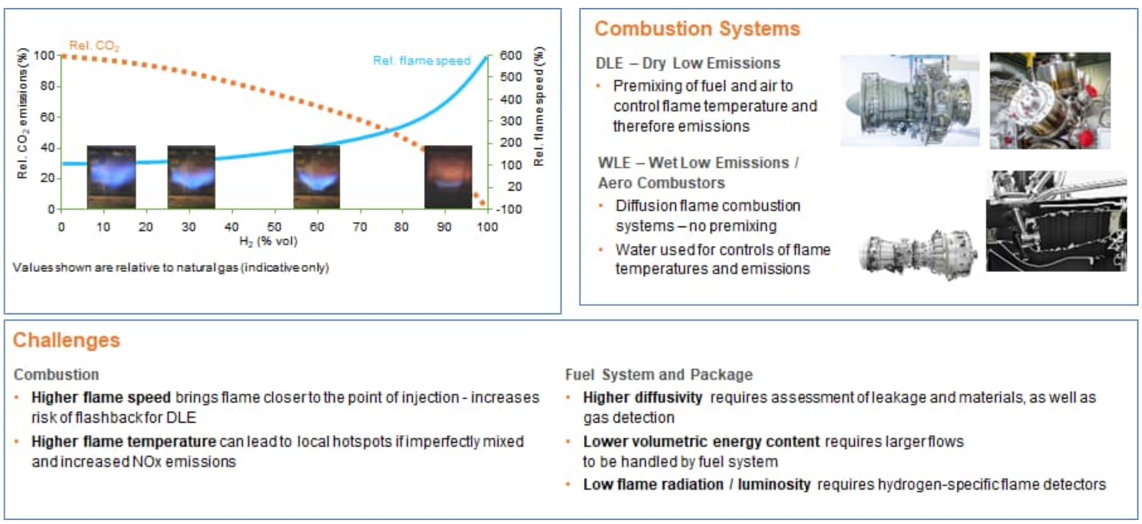

Figure 8. Hydrogen Challenges for Gas Turbines

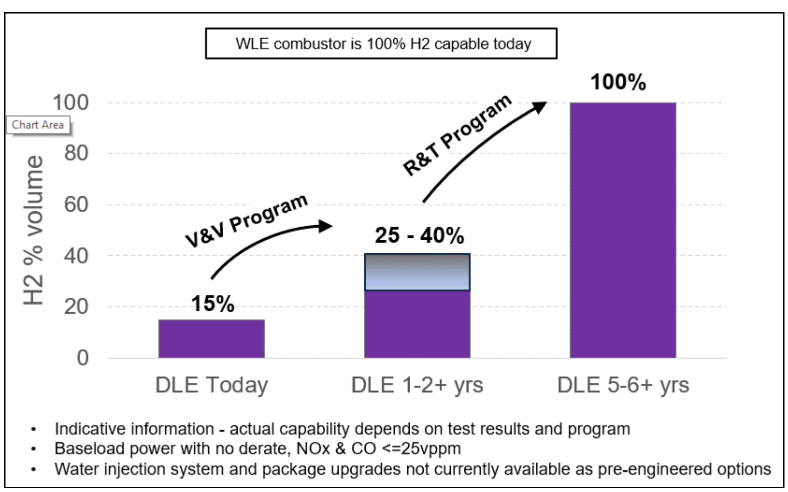

Figure 9. SGT-A35 DLE H2 Combustion Development Roadmap

Effect of Hydrogen on Turbomachinery Component Lives

The pre-FEED study included an assessment of the impact of up to 40% volume of hydrogen on DLE aeroderivative gas turbine component lives. The scope included the following analyses:

- thermodynamic engine performance modelling
- CFD analysis of the combustion system
- Aerothermal analysis of turbine performance including stage loading, heat transfer
- Mechanical integrity assessment of turbine blades and vanes.

The main results are as follows:

- The presence of up to 40% volume hydrogen does not introduce significant changes in main engine cycle parameters (e.g., shaft speeds, pressures, and temperatures in the main gas path), except for small and generally beneficial reductions in turbine inlet temperatures associated with changes in specific heat capacity due to higher water content in the products of combustion.
- There are no significant changes in the combustor flow field or exit temperature traverse (figure 10). Overall combustor gas temperatures remain largely unchanged (noting that primary zone temperature was kept the same as with natural gas).
- The primary zone flame is visibly shorter with hydrogen (figure 10). This is expected as hydrogen has a higher reactivity than natural gas.
- There are no significant increases in combustor liner near wall temperatures or turbine blade and vane metal temperatures (figure 11).

Based on these preliminary results, notwithstanding that full life cycle verification activity is required, we do not expect any impact on component lives and maintenance intervals associated with up to 40% volume hydrogen with respect to the SGT-A35 DLE.

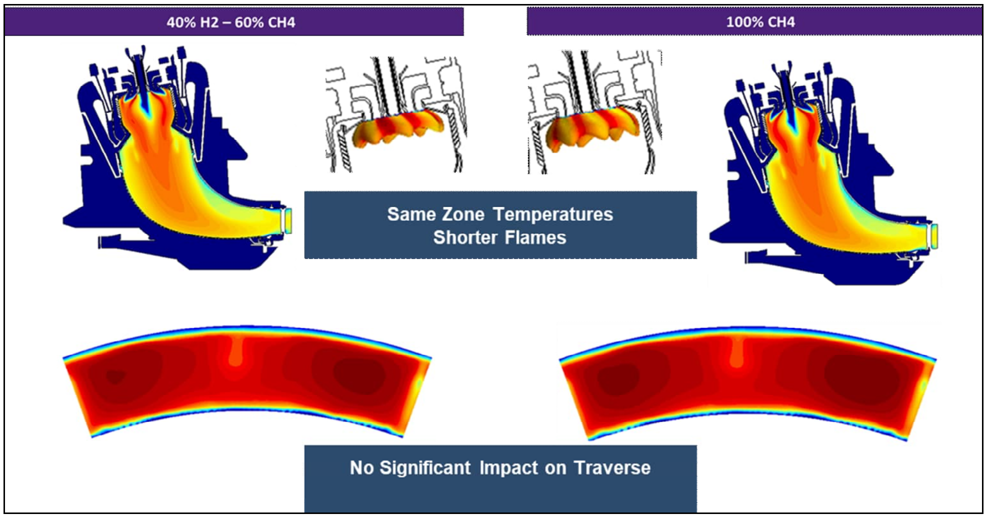

Figure 10. Preliminary Combustor Modelling

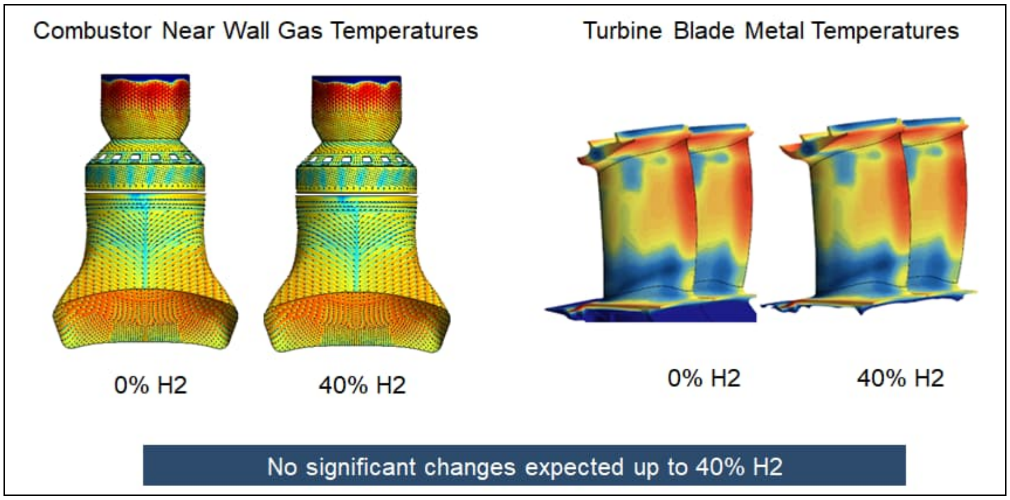

Figure 11. Combustor Liner and Turbine Blade Temperatures

Blending and Gas Turbine Fuel Control

Hydrogen blending and gas turbine controls will be fully integrated to ensure that the hydrogen content of the fuel does not exceed the limit for the SGT-A35 DLE, and that the gas turbine fuel controller takes account of the % volume of hydrogen in the fuel. The latter is necessary for the DLE fuel controller to maintain zone temperatures at the optimum values for emissions and stable combustion.

Figure 12 shows a simplified schematic of the main control elements. The blending skid controller will calculate hydrogen % volume from continuous measurements of natural gas and hydrogen mass flow, coupled with periodic measurements of natural gas composition from the site gas chromatograph (natural gas composition being relatively stable).

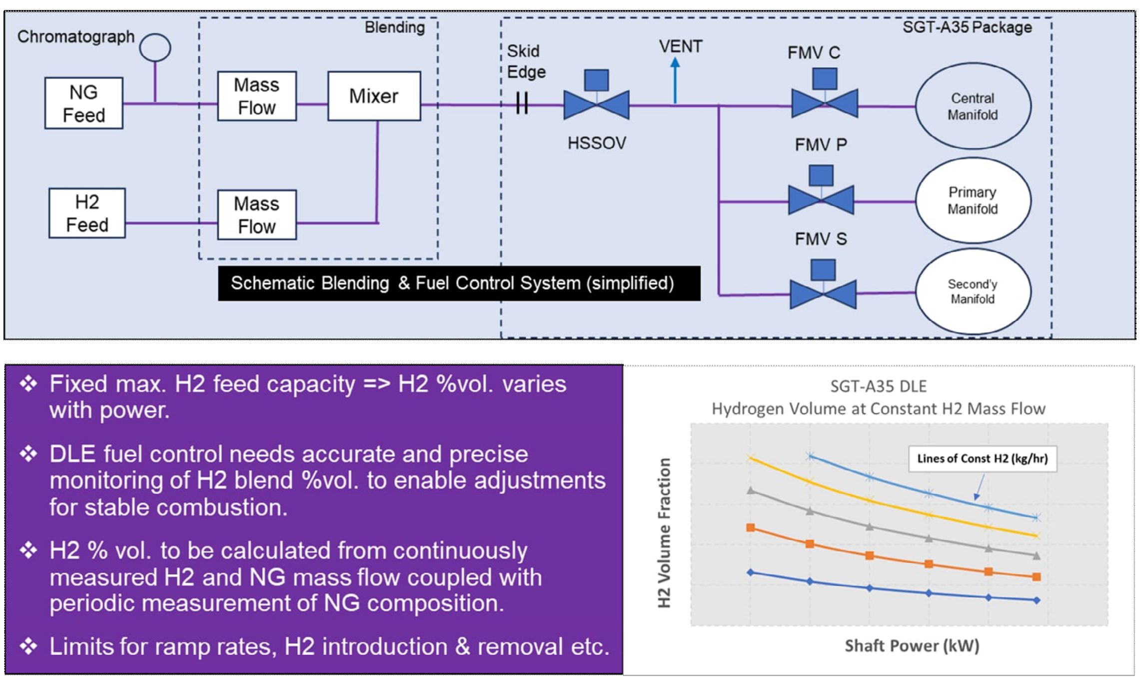

Figure 12. Blending and Gas Turbine Fuel Control

Gas Turbine Package Assessment

The aim of the package assessment was to determine the maximum hydrogen capability without equipment changes, and changes required to operate with increasing volumes of hydrogen up to 40%. The scope was limited to sub-systems located inside the gas turbine enclosure and items that are part of the safety system (e.g., ventilation fans). The main items in scope were:

- Enclosure and Ventilation
- Fire and Gas Detection
- Fire & Gas Suppression
- Gas Fuel System
- Instrumentation and Wiring
- Hydraulic Start

From an electrical standpoint, equipment certification was reviewed with respect to the appropriate gas group for hazardous areas containing hydrogen. During normal operation, hydrogen will not be present inside the gas turbine enclosure (figure 13) unless there is a leak from the package or engine gas fuel equipment. Hydrogen has a wide range of flammable concentrations in air and lower ignition energy than natural gas, which means it can ignite more easily. Consequently, adequate ventilation and leak detection are important elements in the design of safe hydrogen systems. In the event of a leak, hydrogen will be detected by the fire and gas detection system and upon reaching the shutdown LEL (lower explosive level) concentration, the unit will shut down and the fuel will be isolated and vented to a safe area outside the enclosure.

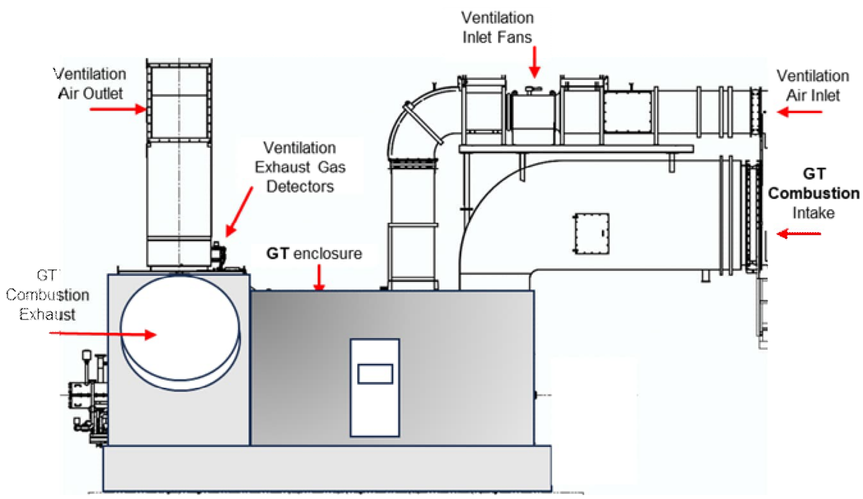

Figure 13. Gas Turbine Package Showing Acoustic Enclosure & Ventilation System

IEC 60079 provides guidance for hydrogen volume % limits per gas group with respect to gas mixtures. The IEC thresholds were used for the purposes of this pre-FEED assessment, as shown in table 1.

NEC Gas Group	IEC Gas Group	Typical Gas	Allowable IEC vol% H2
D	IIA	Methane	25
C	IIB	Ethylene	29
B	IIC	Hydrogen	100

Table 1. IEC Gas Groups and Allowable Volume % Hydrogen

Figure 14 shows some examples of changes that could be required for conversion to hydrogen. Due to the large number of units in service, including different standards and ages of equipment, an engineering assessment of each sub-system and local requirements should be conducted in every case.

The gas fuel system has the most potential to be impacted by higher volumes of hydrogen. The SGT-A35 fuel metering valves are generally certified for IEC IIB but will require recertification or replacement for IIC and materials will need to be assessed for resistance to hydrogen embrittlement. Skid edge pressure, valve capacity and fuel velocity should also be checked to avoid potential operational limitations due to higher volumetric fuel flows with hydrogen blending.

Most of the existing fire and gas detection equipment is certified for IEC IIC, but gas detectors may need to be replaced with catalytic gas sensors, and CFD analysis is required to determine the quantity, location and LEL setpoints of gas detection equipment.

Examples of adaptions to consider	5-25%	25-30%	30-40%
DLE combustor verification test	✓	✓	✓
DLE combustor ignition system certification			✓
Catalytic gas detectors	✓	✓	✓
Gas fuel pipe / manifold materials[2] , fuel velocities	✓	✓	✓
Gas fuel valves certification & materials[2]			✓
Gas fuel skid edge pressure		✓	✓
Gas fuel & vent system purge	✓	✓	✓
Ventilation & gas leak analysis[3]	✓	✓	✓
Controls I/O, logic & protections	✓	✓	✓

1. Showing main items only, not a comprehensive list - engineering assessment of individual cases recommended.
2. Testing for H2 embrittlement required.
3. Ventilation & gas leak analysis by CFD is required to determine quantity, location & LEL setpoints of gas detectors.

Figure 14: Examples of Gas Turbine and Package Adaptions for Hydrogen