Operational, economic and environmental benefits of electrically driven LNG with a combined cycle power plant

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ABSTRACT

The importance of LNG is growing rapidly on a global scale and changes in the market demand innovation in the supporting technologies. Classic LNG plants using gas turbine (GT) driven compressors have plant efficiencies below 40% and the operational flexibility of such a plant depends on the reliability and maintenance schedule of the GT compressor drivers. A modern LNG compression concept: electrically driven compression (eLNG) with a combined cycle power plant (CCPP), offers a solution with higher flexibility, efficiency (in the order of 50%), and availability while minimizing environmental impact. The large economic and social benefits of the modern concept come with challenges that will be examined in this paper.

One of the primary concerns given for eLNG designs is that they need to be connected to a large electrical grid in order to have sufficient robustness to their power supply. As LNG plants are often built far away from electrical grids and transmission lines this study sought to understand the feasibility for an eLNG design that was connected to an islanded electrical power plant. Investigations of the dynamic frequency response of the electrical island following outages of generation or compression are necessary to decide on a suitable plant type and configuration.

The paper presents a typical eLNG plant configuration taking into account the main aspects of system stability, plant availability, generation efficiency, environmental considerations, and overall economic benefits of a modern eLNG CCPP concept.

INTRODUCTION

The eLNG study was undertaken to review the feasibility of this design with particular focus on:

1. Could an eLNG plant be robust in the absence of a grid connected power back-up supply,
2. Were there any interactions (e.g. harmonics) between the electrical supply system and the mechanical drives that would adversely impact the reliability of their operations,
3. How would the power plant and/or eLNG plant respond to major trip events, and
4. What were the potential value drivers associated with the conceptual design.

For the purpose of this study it was assumed that the plant capacity would nominally be 3 × 4 = 12 MTPA of LNG capacity.

POWER PLANT ALTERNATIVES

The power plant for an eLNG design must comply with a number of requirements to match the electrical and often the thermal load requirements of the liquefaction process.

The power plant will operate in island mode to produce the necessary active and reactive power for every mode of operation in the LNG facility. The power plant must follow the actual power demand with fast response to variations. Variations in power demand are caused by changes of process load or variation in generation or both. In all cases the power system must remain stable.

It is important that the power plant provides uninterrupted power to ensure continuous LNG production. Synchronized spare generation capacity must be available in the event of a shutdown of any connected generator. Such synchronized reserve is referred to as N+1 or spinning reserve, where N is the number of generators required to power the LNG facility with one additional generating set securing the reserve capacity to cope with the loss of an individual generator. The spinning reserve capacity is normally distributed (load sharing of active and reactive power) amongst the number of generators in the N+1 operation scheme. This way, all generators on line will contribute in an optimum way for system recovery in case of disturbance to generation. Generator governors and automatic voltage regulators are set for droop mode operation with superimposed frequency and voltage control.

Shutdown of a generator cause instantaneous disturbance to the power balance. The amount of inertia/stored energy (MWs/MW) and speed of response from prime movers (dP/dt) defines the primary control capability of the power plant and is of essence to minimize transient frequency excursions. Restoration of system frequency and voltage following primary control is performed by superimposed, secondary control.

With N+1 operation the prime movers operate at part of rated capacity. Part load effects fuel efficiency and emissions so a careful selection of number and size of generators is needed to establish an optimal power plant configuration.

The relatively high power demand for eLNG designs often leads to the thought of larger turbines. Considering transient stability and part loading, it is important that an analysis of transient behaviour and efficiency versus part load is made.

Apart from the spinning reserve, a reserve capacity for maintenance of any generator is necessary. This reserve is kept as cold stand-by. The concept is referred to as N+2. Down time for generator maintenance exposes the LNG production to the risk of simultaneous faults in the power plant so these maintenance periods must be minimised. A possible way to minimize this down time is to apply an exchange concept for the GT core engines based on having a spare core engine available on site. Once exchanged, the core engine is overhauled on site in a dedicated maintenance work shop before use at the next exchange.

Prior to selection of power plant concept for studies described in this paper the following parameters where analysed for the concept decision.

1. Parameters analysed:
   - o CAPEX
   - o OPEX
   - o Transient stability, frequency and voltage
   - o RAM, Reliability, Availability, Maintainability
   - o Efficiency and cost of fuel
   - o Emissions and possible cost thereof
   - o References of technology
2. Power plant concept options:
   - o Simple cycle, based on medium size (50 MW) industrial gas turbines
   - o Simple cycle, based on large size (170 MW) gas turbines
   - o Combined cycle, based on medium size (50MW) industrial gas turbines

Following above analyses a combined cycle power plant with medium size industrial gas and steam turbines was chosen as base for further studies described below.

OUTAGE OF GENERATION OR LOADS IN AN ELECTRICAL SYSTEM

LNG production plants are operated in almost all cases as an island. Conventional LNG plants operate based on gas turbine driven compressors. Efficiency and availability of these mechanically powered plants are much lower than electrically driven compressors. Electrical LNG systems need less maintenance and are more reliable than mechanical systems. The electrical power necessary to drive the plant must be produced in a power plant operating as an electrical island as an external electrical grid is quite often unavailable in the vicinity of the plant.

The reliability of an electrical island depends on the stability of frequency and voltage in the plant. The sensitivity of an island against these parameters depends on several factors but particularly the outage of the generators or loads. The generation is typically designed following the "N+1 principal" so that outage of one generator does not result in unacceptable frequency instability. The main load components in electrical driven LNG plants are large in relation to the size of the generators and the overall installed generation capacity. In addition, outages of loads are not restricted to individual compressors but to outage of several compressors or, as a worst case outage, to the loss of a whole production train.

Outage of a generator is not only characterized by the loss of active power capacity, but also by the loss of reactive power capacity which changes the system voltage and the load behavior.

To improve the system efficiency to a maximum value (higher than 50%) eLNG's are powered by combined cycle (CC) power plants. The power produced by the steam turbines is strictly related to the availability of the gas turbines. In case of a gas turbine outage the power production in the steam turbine is influenced by loss of a steam turbine or loss of a CC-block.

Another important factor for system stability is the protection of the system against short circuits. The stability of the system (and the generation) depends on the type of short circuit and the time until the fault is cleared. 3 phase faults are more severe but less probable than single phase faults. Typical protection clearing time is 80 -100 ms which is fast enough to avoid generator instability in an islanded electrical system. The longer the fault the longer is the voltage recovery time to reach pre-fault conditions which can influence the behavior of the electrical equipment and, therefore, the behavior of the mechanical compressors.

System frequency stability is one of the most important factors for a reliable eLNG system and is influenced by several factors.

Generators must be protected against under and over frequencies. Typical values are shown in Table 1. Note that project specific values may be different.

Frequency deviation from nominal	Protection settings
+ 2 Hz	direct trip
+1.5 Hz	trip after 20 s
- 2 Hz	trip after 20 s
- 2.5 Hz	direct trip

Table 1. Generation protection in case of over- and underfrequency

Under steady state conditions in an island, the frequency band should be typically + 0.5 Hz to allow small operational actions (switching load, starting motors etc.). A severe outage of generation or loads should be cleared with a suitable safety margin from the generator protection limits or the limits of other critical equipment such as the compressor variable frequency drives. A fault recovery frequency band of +1 Hz is a suitable margin within which the frequency can rise or drop before the generation control is able to restore the frequency back into the operational frequency band. In case of a slow response or insufficient spinning reserve, the frequency is not able to recover so additional counter-measures are necessary. In the case of a large load rejection (e.g. train trip), generation must be shut down to reduce the very fast rise of frequency. In the case of load acceptance with insufficient spinning reserve, load shedding can be utilised to match electrical load with available generating capacity.

Several factors influence the frequency behavior of generators during a transient condition so the complex dynamic response is best investigated by computer simulation. However, a simple model will show the basic relationship.

If the grid is assumed as a simple connection point, the generation is concentrated in one single generator producing the power P to balance the load, and we lose ΔP generation, then the frequency will drop (or rise in case of losing a load ΔP) following the gradient df/dt (known as rate of change of frequency RoCoF):

$$RoCoF = df/dt = \frac{f_0}{2H} \bullet \frac{\Delta P}{P}$$

Here f0 (Hz) is the rated system frequency and H is the inertia of the generator which represents the stored energy W in the rotating (MWs/MW) masses of the turbine-generator-set. Consequently the frequency changes linearly with the relationship of lost load (or generation) to the generated power. This is valid only in the first milliseconds after the outage because a real system control starts to recover the frequency. Therefore, the formula indicates a worst case RoCoF value. With active turbine control the resulting factor is smaller.

The outage of ΔP generation drives the system to an underfrequency (or overfrequency in case of loss of the load ΔP) which can be described by

$$\Delta f_{\min} = \frac{f_0}{2H} \bullet \frac{\Delta P^2}{2P\frac{dP}{dt}}$$

The frequency drop is characterized by the generation inertia which represents power stored in the rotating masses. The turbine governor supports the frequency by increasing power into the system with a power change rate of dP/dt. Typical values of dP/dt are 2-5 %/s.

Note that the frequency drops (or rises) in proportion to the square of the change in power ΔP. This can be critical in an LNG plant where large individual loads or a train can be tripped. In case of a train trip, the turbine dP/dt may be too small to keep the frequency below trip values so an active shut down of generation is necessary. The Δfmin frequency equation enables the necessary dP/dt power changing rate to be calculated to keep the frequency below/above + 1 Hz frequency change. If the activated power is not sufficient to keep the frequency above - 1 Hz, the load shedding scheme must be activated.

The equations underestimate real system behaviors as the time delay to open/close valves and the characteristics of the turbine reduce the power change speed. It is necessary to analyze the system with the turbine governor and automatic voltage regulator to get a realistic frequency minimum or maximum.

Automatic voltage regulator must provide fast recovery from transient load or generation changes. Failing to do that effectively results in change of load with voltage dependent characteristics and additionally impacts the system frequency response.

By knowing the frequency and voltage behavior under the different transient conditions, the necessary countermeasures can be taken into account in the planning phase of the plant. A modern power management system can monitor and respond to these conditions to ensure high reliability of the electrical system.

In this study, the manufacturer standard settings for the selected machinery are used. The settings are for the 50 Hz machinery. There are two sets of the manufacturer settings that apply:

- o for the gas turbine SGT-800, and
- o for the steam turbine SST-400

The settings are shown in Table 2 for the SGT-800 and in Table 3 for the SST-400.

Frequency deviation from nominal	Protection settings
+ 5.0 Hz	direct trip
- 2.5 Hz	30 sec delay
below -2.5 Hz and above – 4.0 Hz	0.3 sec delay
Below - 4.0 Hz	direct trip

Table 2. Manufacturer standard settings for the steam turbine SGT-800

Frequency deviation from nominal	Protection settings
+ 2.5 Hz	10 sec delay
- 0.5 Hz	10 sec delay
- 2.5 Hz	3 sec delay
- 3.0 Hz	5 sec delay

Table 3. Manufacturer standard settings for the steam turbine SST-400

DYNAMIC STUDY OF AN eLNG PLANT UNDER TRANSIENT CONDITIONS

Dynamic voltage and frequency excursions in the eLNG plant in islanded operation can be sufficiently determined by conducting computer-aided simulations. The simulations include various network events such as electrical faults, load rejection and generation outage on the simulation model of the facility. The level of detail of the model is determined by the phenomenon under investigation.

This study uses a detailed model of the eLNG plant. Its main components are the power plant, electrical network and LNG processing plant. The aim of the study is to show that eLNG can provide high reliability and efficiency in LNG production if designed in accordance with standards and guidelines for secure power system operations.

The topology of the electrical grid of the facility is shown in Figure 1. It has three main voltage levels 11 kV, 66 kV and 132 kV. The backbone of the network is the 132 kV power station switchboard, with incoming feeders from the six SCC-800 2x1C generator blocks and outgoing feeders to the LNG plant. The generators are connected to the 132 kV switchboard through the generator step-up transformers. The power plant and the LNG facility operate as an island and there is no connection to an external electrical grid.

The power plant consists of six combined-cycle blocks and the power plant auxiliary load. Each block includes two gas-turbine generators (GTGs) rated 49.2 MW and a steam-turbine generator (STG) rated 40 MW. The link between the gas turbines and steam turbine in a block is the heat recovery steam generator (HRSG). The HRSG is of once-through type. This type of the HRSG provides high degree of flexibility as quick changes in steam production are possible, however, steam reserve is limited and sudden decrease in the GTG produced heat will have an impact on the generated steam and ultimately STG generation within a few seconds. The simulation model captures this behavior.

The LNG processing plant comprises three production trains with compressor drives for cooling and liquefaction of natural gas and the LNG plant auxiliary load.

Each train consists of three compressor units; a propane compressor (C3) rated 57 MW and two MR compressors each 52 MW in size. All trains are considered identical.

The compressors are driven by large synchronous motors controlled by thyristor frequency converters. Such drives are also referred to as variable frequency drives (VFD). The transformers for the converters are connected to the main 132 kV switchboard. The LNG plant auxiliary load is represented as lumped sum and varies with number of trains in operation from 80 MW to 160 MW

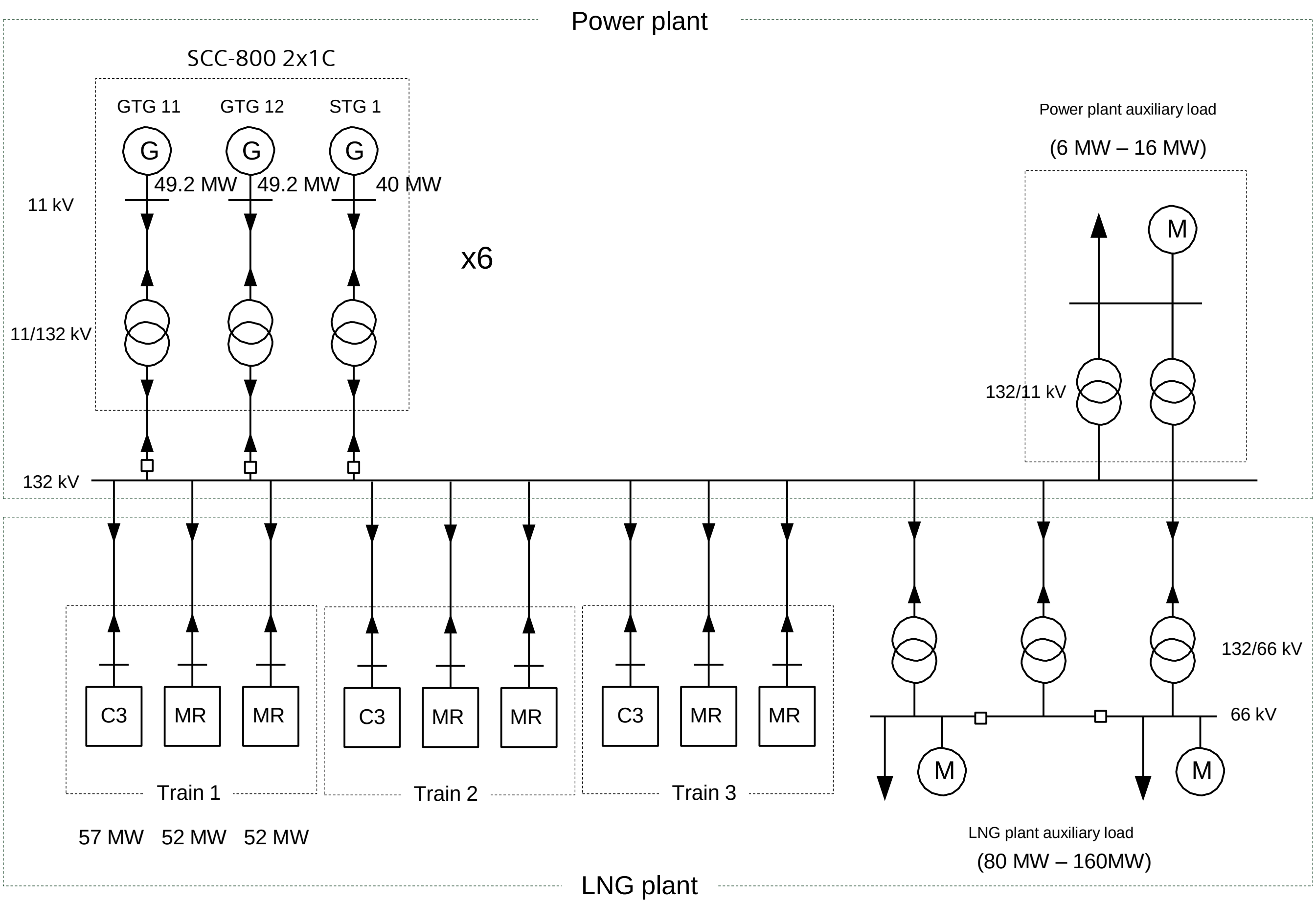

Figure 1. Typical electrical network topology

The dynamic simulations are performed by using PSS®NETOMAC simulation tool. Scenarios investigated are shown in Table 4. In total, 24 scenarios are investigated, including cascading loss or trip of C3 and MR compressors, GTG trip, and GTG trip with consequent STG trip. The scenarios are carefully selected to resemble actual contingencies and operational events. The study results are discussed below.

o Scenario A

This scenario includes tripping of three compressors in a sequence. As shown in Figure 2 the maximum transient frequency and voltage are reached in case A-1 after the third (last) compressor trip at 11 seconds. With reference to Table 2 and Table 3, the overfrequency is not critical for the gas and steam turbine generators.

o Scenario B

In all B scenarios the frequency and voltage excursions are within equipment operating limits and are not critical.

o Scenario C

This scenario includes simulation of a step-wise load rejection as per Table 4. The scenario does not represent any problem for the operation of the facility.

o Scenario D

This scenario includes simulation of a sudden GTG loss followed by a decrease in the power generation of the STG located in the same power block. In scenarios D-1 and D-4 this event results in transient frequency deviation below 49 Hz. Such deviation is considered critical and load reduction is required to improve the frequency. In the study we assume reduction by 10% of the compressor load could be used for the stabilizing purposes of the electrical network. In addition about 10 MW fixed load can be tripped, if required. The frequency can be maintained above 49 Hz at load reduction lower than 10% and further remedial measures, such as load shedding, are not required (Figure 3). Following the load reduction, the facility can continue to operate safely.

o Scenario E

This scenario is a worst-case scenario. It includes sudden loss of a GTG with consequent loss of the STG in the same power block, which is outside the typical design criteria. Due to the severe power imbalance, the frequency goes below 48.5 Hz. Such frequency deviation is considered critical for the VFDs and the STGs. By proper load reduction, as shown in Figure 4, the frequency can be can be improved and kept within limits.

o Scenario F

The results show that trip of C3 compressor(s) is not critical since the maximum transient frequency and voltages are below limits.

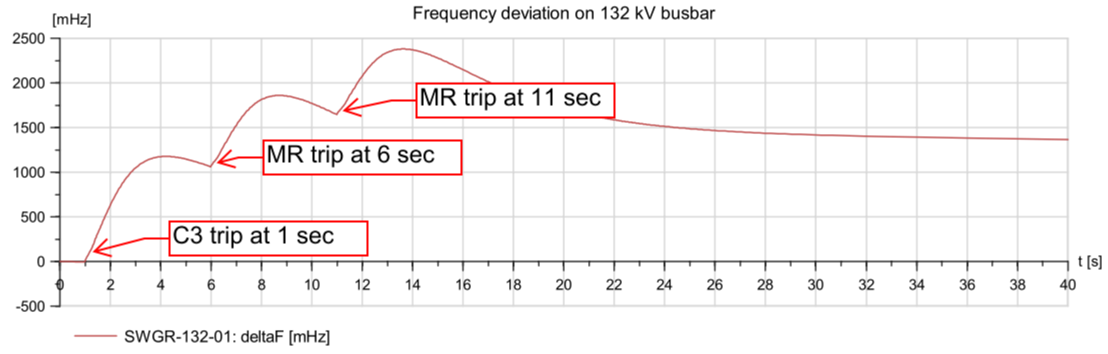

Figure 2. Simulation results for Scenario A-1

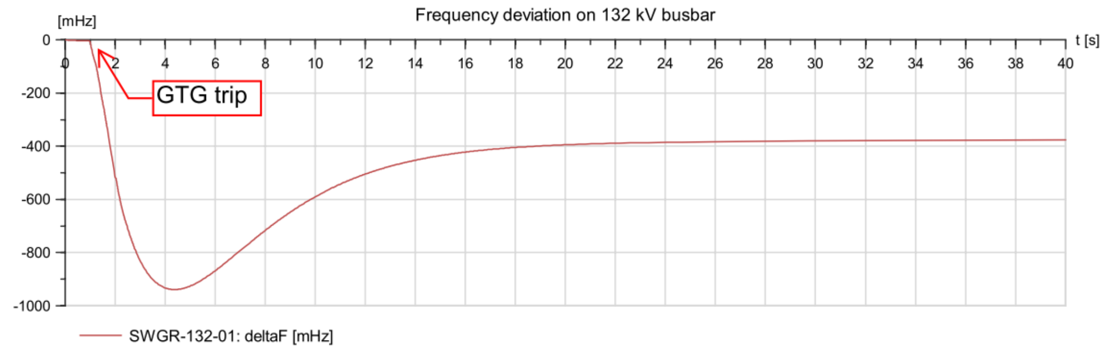

Figure 3. Simulation results for Scenario D-1 with 6% controlled load reduction

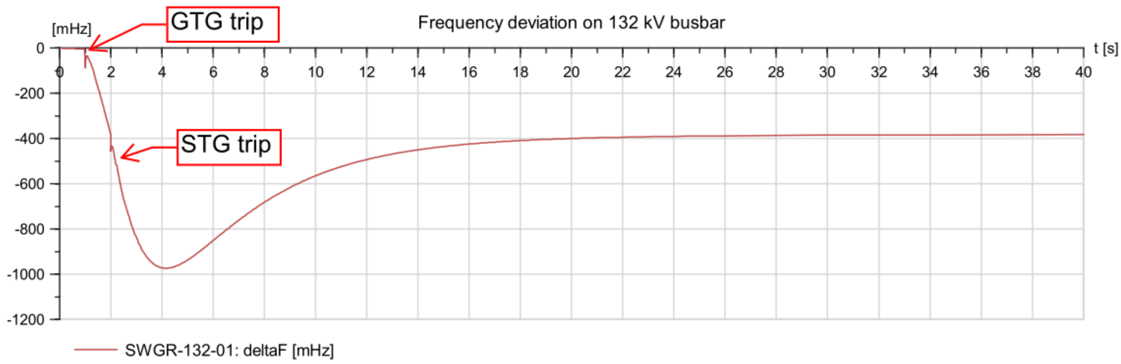

Figure 4. Simulation results for Scenario E-2 with controlled load reduction

Case		Load	Ambient temperature	Power plant Configuration	LNG plant load (MW)	Case description
A	1	1 train	27 °C	5 GTG + 3 STG	240	Cascading loss of C3 compressor, first MR and second MR compressor at 1 sec, 6 sec and 11 sec.
	2		38 °C	6 GTG + 3 STG	247	
	3	3 trains	27 °C	11 GTG + 6 STG	638	
	4		38 °C	12 GTG + 6 STG	659	
B	1	1 train	27 °C	5 GTG + 3 STG	240	Trip of MR compressors into recycle (1 sec), MR compressors stop (6 sec), trip of C3 compressor into recycle (11 sec).
	2		38 °C	6 GTG + 3 STG	247	
	3	3 trains	27 °C	11 GTG + 6 STG	638	
	4		38 °C	12 GTG + 6 STG	659	
C	1	1 train	27 °C	5 GTG + 3 STG	240	Loss of one MR compressor (1 sec), trip of C3 and remaining MR compressors into recycle (11 sec).
	2		38 °C	6 GTG + 3 STG	247	
	3	3 trains	27 °C	11 GTG + 6 STG	638	
	4		38 °C	12 GTG + 6 STG	659	
D	1	1 train	27 °C	5 GTG + 3 STG	240	Loss of GT + ST to 50% output.
	2		38 °C	6 GTG + 3 STG	247	Loss of GT + ST to 50% output.
	3	3 trains	27 °C	11 GTG + 6 STG	638	Loss of GT + ST to 50% output
	4		38 °C	12 GTG + 6 STG	659	Loss of GT + ST to 50% output
E	1	1 train	27 °C	5 GTG + 3 STG	240	Loss of GT (1 sec) + loss of ST (2 sec)
	2		38 °C	6 GTG + 3 STG	247	
	3	3 trains	27 °C	11 GTG + 6 STG	638	
	4		38 °C	12 GTG + 6 STG	659	
F	1	1 train	27 °C	5 GTG + 3 STG	240	Trip of C3 compressor
	2		38 °C	6 GTG + 3 STG	247	
	3	3 trains	27 °C	11 GTG + 6 STG	638	Trip of all C3 compressors
	4		38 °C	12 GTG + 6 STG	659	

Table 4. Simulation scenarios for investigating dynamic performance of the eLNG

The study shows that eLNG, if properly designed and operated, is able to withstand transient frequency and voltage excursions without impact to the LNG production. The overfrequencies are not critical and can be properly mitigated. The results also show that the selected power plant equipment and configuration could withstand loss of power generation under most probable operating conditions. The low probability operating condition cases where the underfrequency was greater than the required limits can be sufficiently mitigated by controlled reduction in load. With load reduction between 13MW (single train operation) – 41 MW (three train operation), within 500 to 800 ms, a safe margin to underfrequency is kept.

TECHNICAL AND ECONOMIC COMPARISON OF THE LNG CONCEPTS

The objective of this section is to compare the technical, economical and business considerations of an eLNG development with a conventional onshore LNG development.

The analysis below compares a three train eLNG plant with power supplied from an adjacent CCPP (or Independent Power Plant, IPP) with a conventional three train onshore LNG development, where the liquefaction gas turbines and power generation unit are included as part of the LNG development.

As a simplification for this study, it was decided not to optimise any heat integration opportunities between the power plant and the LNG plant. i.e. The LNG plant provided fuel gas to a power plant which returned electrical power for the large electric motor driven compressors as well as other LNG plant users.

TECHNICAL FEASIBILITY

It was concluded that an eLNG development is technically feasible and no show stoppers were identified.

REVENUE

The main benefit of an electrical driven LNG development is that it can produce more LNG annually and therefore generate more annual revenue. The additional LNG production is anticipated based on the following considerations:

- o The power supply reliability expected from a CCPP (utilizing normal design and operating power generation sparing philosophies) is high (close to 100%), which will with the combination of electrical motors result in an increase in the overall availability (+2% expected) as compared to a conventional LNG development using gas turbines.

- o This incorporates that the planned maintenance turnaround schedule for an electrical driven LNG facility will be shorter since the gas turbines maintenance will be managed separately in the power plant which has a spared power (utility) configuration.

- o The annual capacity of conventional LNG facilities using gas turbines are significantly impacted by the swings in seasonal and daily ambient temperatures. The annual capacity for electrical driven LNG facilities is expected to increase by minimising production swings due to changes in ambient temperature and associated gas turbine supplied power.

CAPITAL COST (CAPEX)

The Capital cost for an electrical driven LNG facility with an adjacent CCPP was assessed to be similar to a conventional LNG development. The eLNG concept also opens up potential capex reduction advantages (not quantified in the study) by bringing more suppliers into the market and leveraging the highly competitive and well defined electrical power industry knowledge into our (adjacent) industry.

Capex disadvantages for an eLNG development
More equipment (i.e. gas turbines) are required to guarantee a high reliability in power supply.

Capex advantages for an eLNG development
The CCPP to be designed, constructed and operated using power plant standards as oppose to oil and gas standards.
Separation of the CCPP from the main LNG development introduces more competition and can reduce overall execution risk.

OPERATING COST (OPEX)

The analysis assumed that the operating cost will be similar for the eLNG and conventional LNG facilities. There are potential opportunities to reduce the Opex for the eLNG and CCPP development option considering the potential to leverage international power industry operational best practices. However further work will be required to quantify this opportunity. For the purpose of this analysis Opex was considered to be neutral.

ENVIRONMENT

Greenhouse Gas (GHG) emissions are expected to be lower for an eLNG plant together with a CCPP. The efficiency gain using a CCPP as compared to conventional open cycle gas turbines (incorporating waste heat recovery) to drive the LNG process is significant and are likely to result in a reduction in GHG emissions.

OTHER POTENTIAL BUSINESS BENEFITS (NOT INCLUDED IN ECONOMIC ANALYSIS)

The concept of an electrical driven LNG facility with an adjacent CCPP can potentially deliver additional business opportunities, for example

- Economies of scale advantages if the CCPP can provide power to the electrical driven LNG facility as well as to other users (e.g. national grid).
- Potential synergies between the CCPP and the LNG facility such as desalinated and potable water supply.
- The overall schedule might benefit from separating the LNG development and the CCPP development.
- The capital efficiency (IRR and VIR) of the LNG development might improve if an IPP is built, owned and operated by another commercial entity. The investment hurdle rates for an IPP are usually lower than what is required typically for a LNG development.

CONCLUSION

The report found that there were no technical showstoppers identified that would prevent an eLNG plant from operating robustly in conjunction with a well-designed islanded power system.

The conclusion from the eLNG study was that:

- It is technically feasible to operate an eLNG plant with an islanded power supply.
- It is possible to mitigate any adverse interactions between the power system and the mechanical drives by good design practices.
- There will be higher revenues resulting from increased availability as well as process optimisations.
- The Capex/Opex was assessed as being neutral between an eLNG and a conventional LNG design, with scope for reductions in eLNG costs in future studies.
- The use of a CCPP will reduce air emissions into the environment.
- The eLNG concept can potentially add material business value to future Greenfield LNG developments.

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