Economics of Operating a Gas Turbine Fuelled with Hydrogen Produced by Electrolysis and Renewable Energy

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1.1 Summary

There is currently significant federal and state government enthusiasm for the development of a hydrogen industry in Australia. One of the perceived applications is the production of 'green' hydrogen through the electrolysis of water powered by electrical energy sourced from wind and solar farms.

This paper uses the existing Tallawarra natural gas fuelled peaking power plant as a template for the replacement of natural gas with hydrogen and calculates the comparative system efficiencies and fuel costs. Underpinning this exercise was the extraction and analysis of empirical operational data from the National Electricity Market (NEM) files for the Tallawarra plant's performance for FY2020-2021.

A system consisting of a General Electric Model 9F.04 gas turbine operating in combined cycle mode fuelled by 100% hydrogen produced by 24 ITM Power HGASXMW electrolysers was developed. The system was then analysed to identify the technical parameters and to calculate the system economics. A Discounted Cash Flow (DCF) analysis was undertaken over a 20-year period to determine the minimum selling price for the hydrogen delivered to the gas turbine.

The following results were obtained:

- Hydrogen fuelled system efficiency - 33.26%
- Electrolyser efficiency - 55.25%
- Minimum selling price of hydrogen - $39.34/GJ
- Cost of natural gas - $11.30/GJ.

There is clearly a significant price difference which, in turn, will result in higher electricity prices fed back to the NEM grid.

It is also evident that the hydrogen fuelled system efficiency of 33.26% compared with a natural gas fuelled gas turbine efficiency of 60.2% (combined cycle mode) is wasteful of energy.

Unless there is a dramatic reduction in the cost of renewable electrical energy and the capital and O&M costs for electrolysers, green hydrogen is not competitive with natural gas as a fuel for gas turbines.

Alternatively, a dramatic increase in the price of natural gas coupled with high subsidies for hydrogen production could make hydrogen fuel competitive; however, in view of the comparative system efficiencies, this would make little sense.

1.2 Introduction

1.2.1 Government Policy

The Council of Australian Governments (COAG) was the peak intergovernmental forum in Australia. The members of COAG were the Prime Minister, state and territory First Ministers and the President of the Australian Local Government Association (ALGA). The Prime Minister chaired COAG.

In May 2020 the Prime Minister announced the cessation of the Council of Australian Governments (COAG), including the former COAG Energy Council[1]. The COAG Energy Council has been replaced by the Energy National Cabinet Reform Committee (ENCRC) and the Energy Ministers' Meeting (EMM). These are Ministerial forums for the Commonwealth, states and territories and New Zealand to work together on priority issues of national significance and key reforms in the energy sector. As a sub-committee of the National Cabinet, ENCRC have been tasked with the following key priorities to deliver in 2021:

- immediate measures to ensure reliability and security of the electricity grid ahead of the 2020-21 summer
- the redesign of the National Electricity Market to take effect after 2025
- a package reforms to unlock new gas supply, improve competition in the market and better regulate pipelines.

Prior to the reorganisation, the COAG Energy Council published a paper entitled 'Australia's National Hydrogen Strategy' which advised the following:

Hydrogen can also be used to generate electricity (through fuel cells or being burned to drive turbines). If made when there is surplus or cheap electricity available, hydrogen can be stored and then used to produce electricity when there is insufficient electricity available from other sources. Hydrogen can also be used in combination with renewable electricity to power remote sites like mines and small regional communities.

Similarly, the COAG paper advises:

Electrolysers, which use electricity to produce hydrogen, can take advantage of excess power when wind and solar generators are operating at capacity. They can be rapidly ramped up or down to provide demand response and frequency control

[1] https://www.coag.gov.au/coag-councils

services to the electricity grid. At times when the electricity grid is under pressure, hydrogen production can be halted, and stored hydrogen converted back to electricity when needed to meet peak electricity system needs. Used effectively this could allow for better integration of renewable energy technologies into Australian electricity grids and improved investment confidence for renewable energy projects. Further, it would increase options for electricity market operators to maintain power supplies in an emergency, improving energy supply security and reliability.

1.2.2 Hydrogen Production

Hydrogen can be made either by electrolysis, which uses electricity to disassociate the hydrogen from the oxygen in water, or steam methane reforming (SMR), in which energy, usually natural gas, is used to raise steam. The steam is then brought into contact with a catalyst and an additional supply of natural gas to extract hydrogen from both, generating carbon dioxide in the process

While these processes are technically and commercially viable for the manufacture of hydrogen for industrial use, they require significant energy input. As a result of the energy losses in the hydrogen production processes, it will usually be preferable to use electricity and natural gas directly, rather than in the production and burning of hydrogen. Hydrogen produced from electrolysis and SMR is always in economic competition with its own inputs, electricity and natural gas. This has clear cost ramifications for the electricity consumer.

Noting that the SMR process with no carbon capture and storage produces approximately 8.5 kg of CO2 per 1 kg of hydrogen[2]. SMR, presumably, must therefore be discounted as a production method in view of Federal and State Governments' net zero emissions vision. Accordingly, this paper will focus on the electrolysis of water.

This paper uses the information available in January 2021 on the actual cost and performance of ITM Tableware Proton Exchange Membrane (PEM) Electrolysers. The choice of PEM rather than Alkaline technology follows the advice in the Aurecon 2019 Cost and Technical Parameter Review Clause 4.9.3 which states:

For hydrogen production, PEM electrolysers have been growing in popularity relative to more traditional Alkaline technology. This is primarily due to the improved dynamic operation of the PEM-based technology with improved responsiveness and improved current densities. PEM also produces hydrogen at around 30 bar compared to atmospheric pressures achieved with Alkaline electrolysers which reduces the need for costly first stage compression.

[2] COAG Energy Council's paper 'Australia's National Hydrogen Strategy'.

1.3 The System

Noting the quotation at Section 1.1.1 that, '*electrolysers, which use electricity to produce hydrogen, can take advantage of excess power when wind and solar generators are operating at capacity.*', the system in this paper assumes that the electrolyser will be powered by electrical energy sourced entirely from wind and solar farms. Accordingly, the system consists of the following elements;

- Renewable Energy
- ITM Power HGASXMW electrolysers
- Compression System
- Gas turbine, GE Model 9F.04 operating in Combined Cycle mode with a 443 MW nameplate rating. Figure 1 provides an overview of the system.

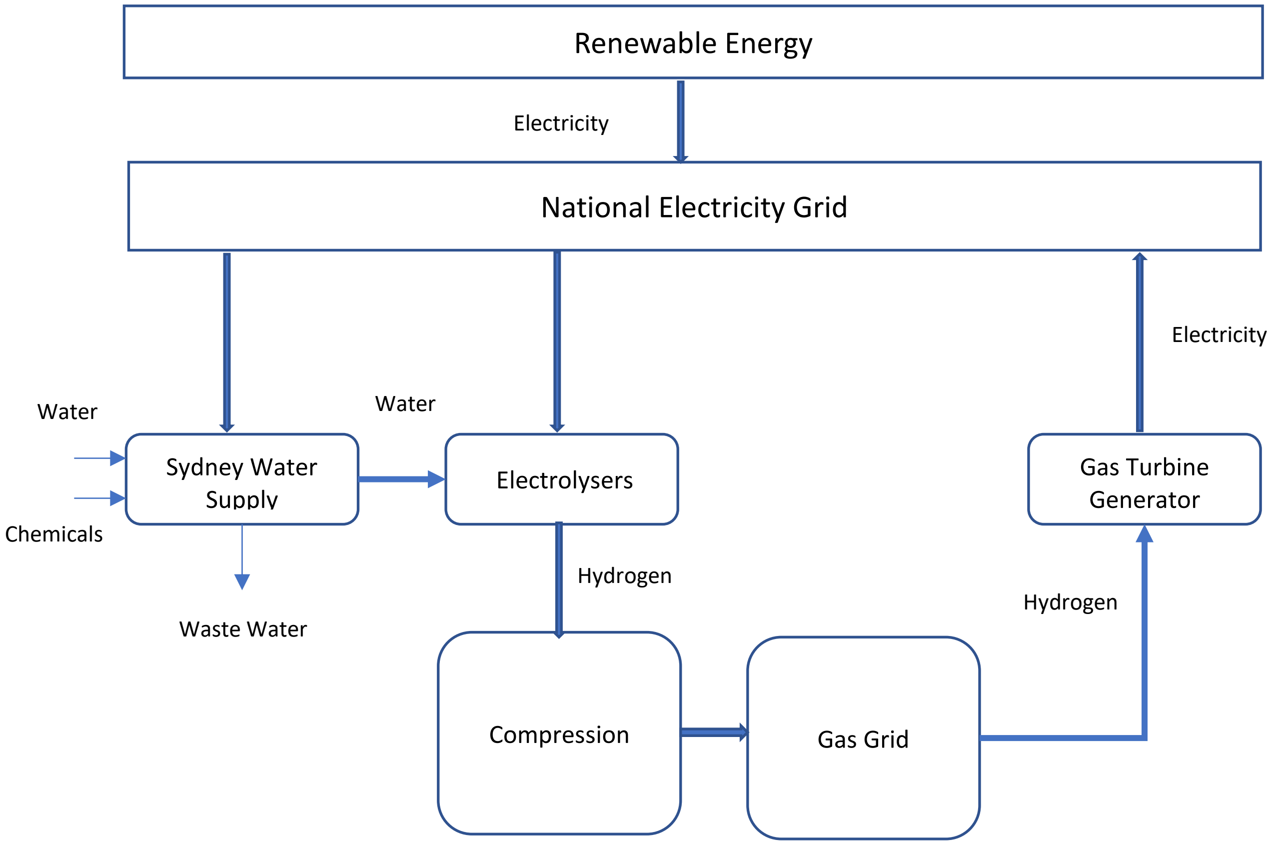

Figure 1 System Overview

The system is based on the existing Tallawarra peaking power station which is a 440-megawatt combined cycle natural gas power station in the city of Wollongong, New South Wales. Operational data generated by Tallawarra for the 2020-2021 Financial Year was extracted from the National Electricity Market (NEM) files and analysed to determine, inter alia, the annual electrical energy output from the power plant. Table 1 summarises the Tallawarra peaking power station data.

Parameter	Data
Maximum Out put	440 MW
Operating hours	2,329.50 hours
Total Energy Supply	675,230.08 MWh
Average output for operational hours	289.86 MW
No. of 24-hour operational days	43.00 days
Total No. of Operating days	194.00 days
Maximum Daily Energy	8,691.58 MWh
Average Maximum Daily Energy	4,514.84 MWh

Table 1 Tallawarra Power Station Data FY 2020-2021

The system is designed to produce sufficient H2 to power the gas turbine instead of using natural gas to provide the annual energy output (675,230.08 MWh). The electrolysers are powered exclusively by electricity sourced from renewable energy.

The water supply to the electrolysers is sourced directly from the water mains and hence no storage is required which reduces capital costs.

It is envisaged that the electrolysers and compressors will be located within one kilometre of the existing Tallawarra power station and that the existing natural gas pipeline could be converted to convey the hydrogen to the gas turbine. The H2 will require additional compression and the gas pipeline will provide the required storage to obviate the capital costs of dedicated H2 storage tanks. It is also assumed that renewable energy will be available 24 hours per day at the Levelised Cost of Electricity (LCOE) for wind generation.

1.4 System Analysis

1.4.1 Technical Calculations

Table 2 summarises the requirements to operate a GE 9F.04 gas turbine using 100% hydrogen sourced from the HGASXMW electrolysers.

Gas Turbine Data	Quantity	Comments
Nameplate power Output	443 MW[3]	Operating in Combined Cycle mode (CCGT)
CCGT Efficiency	60.2%[4]	

[3] https://www.ge.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/products/gas-turbines/9f-fact-sheet-product-specifications.pdf'
[4] ibid

Annual electrical energy generation	675,230.08 MWh	Data for FY20-21 sourced from NEM data files
Annual energy generation expressed in GJ	2,430,828.30 GJ	675,230.08 MWh*1000*3.6 MJ/kWh/1000
Annual energy consumed by CCGT	4,037,920.76 GJ	2,430,828.30 GJ/60.2%
Annual H2 fuel consumption by CCGT	33,649,339.70 kg	4,037,920.76 GJ*1000/120 MJ/kg (LHV for H2 is 120 MJ/kg)
HGASXMW Electrolyser Data	**Quantity**	**Comments**
Electrolyser Production	4,050 kg/24h[5]	
Electrolyser Electricity Power required	10.07 MW[6]	
Water required to produce 1 kg of hydrogen	9.9 litres/kg[7]	
Operational availability	95.89% (350 days)[8]	350 days per annum
Technical life of electrolyser	20 years[9]	
Daily H2 production required to meet annual fuel consumption	96,140.97 kg/day	33,649,339.70 kg (/365 days*95.89%)
Number of electrolysers required to meet daily H2 fuel demand	23.74 electrolysers	96,140.97 kg/day/4050 kg/day Round up to 24 electrolysers
Annual hydrolyser electrical energy demand	2,030,112.0 MWh	24 electrolysers * 10.07 MW * 8760 hours * 350d/365d
Efficiency Calculations		
Electrolyser energy output	1,121,644.66 MWh	675,230.08 MWh/60.2% (Electrolyser output = CCGT input)
Electrolyser energy demand	2,030,112.0 MWh	
Electrolyser efficiency	55.25%	(1,121,644.66 MWh/2,064,188.88 MWh) * 100
System efficiency	33.26%	(675,230.08 MWh/2,030,112.0 MWh MWh) * 100

Table 2 Gas Turbine and Electrolyser Specifications

[5] https://www.itm-power.com/images/Products/HGasXMW.pdf
[6] ibid
[7] Aurecon Report 2019 Costs and Technical Parameter Review
[8] ibid
[9] ibid

1.4.2 System Capital Cost and O & M Calculations

Table 3 summarises the system costs, using the data from Table 2.

Parameter	Calculations	Costs
Capital Cost of Electrolysers		
Capital cost of electrolyser unit[10] per MW	800,000 GBP @ 1.84 Exchange rate	$1,472,000.00 per MW
Capital cost of 24 electrolysers	$1,472,000.00 * 24 * 10.07 MW	355,752,960.00
Land cost. Based on plant being constructed within existing Power Station Site	0.1 * $355,752,960[11]	35,575,296.00
Electrical Grid Connection Cost	$5,000,000.00	5,000,000.00
Compression and Pipeline Grid Connection Cost (estimated 1km)	Based on 1 km connection plus $1 million for compression[12]	$2,500,000.00
Total Electrolyser Capital Costs		**$398,828,256.00**
Operational and Maintenance Cost of Electrolysers		
Cost of electricity sourced from wind farms		$48/MWh[13]
Cost of water consumed from Sydney Water[14]		$2.38/kl plus $ 308.83/quarter service charge (100 mm connection)
Sydney Water connection charge		$308.83/quarter (100mm connection)
Annual Water Consumption	333,128,463 l (9.9l/kg * 33,649,339.70 kg)[15]	
Annual electricity costs to power electrolysers	$48 * 24 electrolysers * 10.07 MW * 8760 hours * 95.89% (Ao)	$97,445,376.00
Annual cost of water	($2.38/kl * 333,128,463 l)/1000 + ($308.83*4)	$794,081.06

[10] https://www.rechargenews.com/energy-transition/green-hydrogen-itm-power-s-new-gigafactory-will-cut-costs-of-electrolysers-by-almost-40-/2-1-948190
[11] Based on 10% of CAPEX costs - Aurecon Report 2019 Costs and Technical Parameter Review
[12] ibid
[13] CSIRO Gencost Apx Table B.8 Electricity generation technology LCOE projections data, 2019-20 $/MWh
[14] Sydney Water website
[15] Includes 10% for water cooling and other losses - Siemens Electrolyser uses 10l/kg

Parameter	Calculations	Costs
Annual Operation and Maintenance costs for 24 electrolysers	0.03 * $355,752,960.00[16]	$10,672,588.80
Annual Operation and Maintenance costs for 24 electrolysers		$108,912,046

Table 3 System Capital and O & M Cost Calculations

1.4.3 Discounted Cash Flow Analysis

A Discounted Cash Flow (DCF) analysis was conducted to determine the minimum selling price of the H2 fuel delivered to the Gas Turbine for subsequent conversion to electrical energy. The DCF parameters are tabulated at Table 4.

Parameter	Value	Comments
Technical life of electrolysers	20 years	
Discount rate	8%	
Cost Inflation rate	3%	
Revenue Inflation Rate	2%	
Initial capital Cost	$398,828,256.00	
Initial Annual O&M Costs	$108,912,045.86	
End of Life removal Costs (Year 21)	$71,151,592.00	
End of Life Land Sale	$35,575,296.00	
Hydrogen Selling Price	$39.34/GJ	Determined by Excel goal seeking function to result in $0 NPV

Table 4 DCF Parameters

The data and spreadsheet underpinning the DCF calculations are available upon request.

1.4.4 A Lower Electrolyser Capital Cost Scenario

ITM claims[17] that it expects to achieve a 37.5% reduction in the cost of large electrolysers over the next three years. This reduces the cost to £500,000/MW ($920,000/MW) which, intuitively, would result in a significant reduction in the cost of H2 per kilogram.

[16] 3% of Capex - Aurecon Report 2019 Costs and Technical Parameter Review
[17] https://www.rechargenews.com/energy-transition/green-hydrogen-itm-power-s-new-gigafactory-will-cut-costs-of-electrolysers-by-almost-40-/2-1-948190

To test this claim, a DCF analysis was undertaken using the same rate parameters at Table 4 with cost items reflecting the reduced Engineering Procurement and Construction (EPC) cost. The results are summarised at Table 5.

Parameter	Value	Comments
Initial capital Cost	$252,080,160.00	
Initial Annual O&M Costs	$104,909,825.06	
End of Life removal Costs (Year 21)	$44,469,120.00	
End of Life Land Sale	$22,234,560.00	
Hydrogen Selling Price	$34.75	Determined by Excel goal seeking function to result in $0 NPV

Table 5 DCF Analysis for Reduced Electrolyser CAPEX

It is evident that a significant reduction in electrolyser costs does not result in a corresponding reduction in the selling price of hydrogen.

1.4.5 DCF Sensitivity

As discussed, the DCF analysis is based on the parameters detailed in Table 4. A further analysis was undertaken to determine the minimum selling price based on the parameters at Table 6.

Discount Rate	Cost Inflation Rate	Revenue Inflation Rate	Minimum Selling Price ($/GJ)
4%	2%	0%	$43.29
4%	2%	4%	$29.89
4%	3%	0%	$47.02
4%	3%	4%	$32.49
8%	3%	2%	$39.34 [18]
12%	2%	0%	$50.74
12%	2%	4%	$39.09
12%	3%	0%	$53.30
12%	3%	4%	$41.07

Table 6 DCF Sensitivity Analysis

1.4.6 Government Subsidy

According to the NSW Government's hydrogen strategy[19], a stretch target price of $2.80/kg is envisaged. To determine the impact of this target, a further DCF analysis

[18] These parameters underpin the analyses in this paper.
[19] NSW Hydrogen Strategy: Making NSW a global hydrogen superpower dated October 2021.

was conducted using the parameters at Table 4 and a minimum selling price of $23.33/GJ ($2.80/kg). This analysis demonstrated that an annual government subsidy in the order of $64 million would be required.

1.5 Observations

The DCF analysis demonstrates that the gas turbine operator will purchase green H2 fuel produced by electrolysis powered by renewable wind energy at $39.34 per GJ. CSIRO data which informs government decisions nominates a natural gas fuel price of $11.30 per GJ for CCGT operation in its Levelised Cost of Electricity Calculations.[20]

There is clearly a significant price difference which, in turn, will result in higher electricity prices fed back to the NEM grid.

It is also evident that the H2 fuelled system efficiency of 33.26% compared with a natural gas fuelled gas turbine efficiency of 60.2% (combined cycle mode) is wasteful of energy.

In addition, when the intermittent nature of renewable energy is taken into account (i.e., a capacity factor in the order of 33%), then a total of 72 electrolyser units would be needed with capital and operating costs increasing three-fold. Due to the intermittent nature of renewable energy, the system would need the energy demand to be firmed. Wind droughts up to 74 hours have occurred in the NEM in the last 10 years. If battery storage is to provide firming energy for a wind drought, the capital and operating costs would be significantly increased.

For example, consider a scenario where a wind drought of 30 hours duration occurs. During the drought, solar energy is available for 15 hours with batteries supplying the remaining 15 hours of energy demand. Therefore, the batteries must be capable of providing 10,876 MWh (72 electrolysers * 10.07 MW * 15 hours). Using data from the Hornsdale Battery in South Australia, which can supply 194 MWh, 56 (10,876 MWh/194 MWh) batteries the size of Hornsdale would be required to meet the electrolyser demand. The Hornsdale Battery Farm cost $213,000,000.00; hence, 56 similar batteries would cost $11,928,000,000.00 ($213,000,000*56).

The batteries would, of course, need to be recharged. Typical battery round trip efficiency is in the order of 80%. This means 13,595 MWh of energy sourced from renewable energy generators would be required to recharge the batteries. The cost at the LCOE rate for wind farms ($48/MWh) would be $652,560.00. It must be noted that wind droughts of up to 74 hours have occurred in the National Energy Market over the last 10 years.

For a wind drought of 74 hours, the cost for battery firming is in the order of $23 million per event.

[20] CSIRO Report GenCost 2019-2020.

1.6 Conclusion

Unless there is a dramatic reduction in the cost of renewable electrical energy and the capital and O&M costs for electrolysers, green hydrogen is not competitive with natural gas as a fuel for gas turbines.

Alternatively, a dramatic increase in the price of natural gas coupled with high government subsidies for H2 production could make H2 fuel competitive; however, in view of the comparative system efficiencies, this would make little sense.

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