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Renewable Hydrogen requirements and impacts for network balancing: a Queensland case study

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Abstract

Hydrogen is the gas of the moment: an abundant element that can be created using renewable energy, transported in gaseous or liquid form, and offering the ability to provide energy with only water vapour as an emission. Hydrogen can also be used in a fuel blend in electricity generation gas turbines providing a low carbon option for providing the peak electricity to cover high demand and firming.

While the electricity grid is itself transforming to decarbonising, hard-to-abate industries such as cement and bauxite refineries are slower to reduce emissions, constrained by their high temperature process requirements. Hydrogen offers a solution allowing onsite production, process heat, with waste heat recovery supporting blended gas turbine generation for onsite electricity supply.

This article builds on decarbonisation pathway simulation results from an ANEM model of the electricity grid identifying the amount of peak demand energy required from gas turbines. The research then examines the quantity, flow rate, storage requirements and emissions reduction if this peak generation were supplied by open cycle hydrogen capable gas turbines.

Keywords: renewable hydrogen, hydrogen capable gas turbines, network balancing, carbon offsets, electricity markets

JEL codes: Q42, Q48, Q55, L94, C61

1. Introduction

In the 12 months to July 2023, the total electricity generation in Australia was approximately 207.66 TWh with coal, gas and oil contributing 63%. Renewable energy sources such as solar, wind and hydro contributed 16.2%, 13.2% and 7.5% respectively. However, the social pressure to address climate change is expected to see a more rapid decline in fossil fuel fired power stations, especially coal fired power stations. The Australian Energy Market Operator (AEMO) predicts that its 2022 middle range scenario "step change" will be the most likely with annual electricity consumption doubling by 2050, as transport, heating, cooking

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and industrial processes are electrified. AEMO expects that by 2031-32, coal and gas will account for 33% of electricity generation, and by 2042-43 only natural gas will remain as a fossil fuel for generation. By 2050, a nine-fold increase in grid-scale wind and solar capacity will be required with a further five-fold increase in household and business solar. Three times the amount of hydro power and batteries will be required to enable a secure, reliable and affordable electricity supply for Australia's growing population.

In Queensland the transition will be more rapid with a government-endorsed goal of 80% renewable energy sourced electricity generation by 2034-35. In the Queensland Energy and Jobs Plan (QEJP)[4] renewable energy sources are expected to dominate generation from 2030 and a sharper decline in thermal coal for domestic use. Millmerran will be the only coal fired power station operational in the state from 2034 and it is forecast to close in 2038. Coal fired power stations will be replaced by 25GW of new solar and wind farms. Pumped hydro capacity will treble with planned stations such as Lake Borumba completed in 2029-30 and Pioneer Valley completed in 2034-35, followed by further increases in large scale solar and wind farms. The QEJP proposes power station sites to become energy hubs for operations and maintenance, hydrogen generation and storage. In addition, these sites can convert existing rotors and turbines and additionally host synchronous condensers for grid stability and blended gas turbines (natural gas blended with hydrogen having reduced emissions).

In this article, attention has been restricted to peaking open cycle gas turbine (OCGT) models. Whilst combined cycle models are readily available, given Queensland's vast VRE resources, they are considered likely to be too inflexible (viz. steam cycle, non-negative minimum stable loads in a solar rich region etc) and take longer to startup and synchronise with the grid than is the case with open cycle models.

The industrial processing sectors are also exploring hydrogen and associated hydrogen derivatives as a generation and fuel source. North Asia and Europe are wanting to import green hydrogen for industrial and domestic uses. This industry is supported by Queensland Government's Hydrogen Industry Strategy[5] and the Renewable Energy and Hydrogen Jobs Fund[6]. Queensland sees hydrogen as a growth area and useful where production can be located close to the use to reduce the issues of transfer / storage of hydrogen.

For those industries which require high temperature heat processing, hydrogen is also offering a pathway to energy decarbonisation. Two hard-to-abate emission industries, cement manufacture and bauxite refining, are examples where hydrogen can be used for process heat.

2. Literature Review

[4] www.epw.qld.gov.au/energyandjobsplan.
[5] Queensland Hydrogen Industry Strategy (statedevelopment.qld.gov.au).
[6] Queensland Renewable Energy and Hydrogen Jobs Fund - Queensland Treasury.

While there is considerable interest in using renewable hydrogen in helping to decarbonise hard-to-abate sectors, the application of interest in this article is the use of hydrogen-based fuel blending to produce a syngas capable of fuelling hydrogen-capable gas turbines to produce electricity in peak times.

Hydrogen fuelled gas turbines have an important role to play in future energy systems (Oberg, Odenberger, Johnsson, 2022). At present gas turbines have the capability to burn 30% hydrogen/70% natural gas blend (by volume) and in limited cases to 100% hydrogen (ETN Global, 2020). This is expected to improve as the Original Equipment Manufacturers (OEMs) keep developing hydrogen combustion capability. Hydrogen must be supplied to a gas turbine at a high purity and under OEM specified temperature and pressure.

Green hydrogen is hydrogen produced via renewable power generation sources such as solar, wind and battery that powers water electrolysis (IRENA, 2022, p.8). Renewable power generation for hydrogen production is most viable when a country or region has natural resource advantages such as high quality solar and/or wind, and abundant and relatively low-cost land; for example, the state of Queensland in Australia (Bischof-Niemz and Creamer, 2023).

The storage options for hydrogen come under three broad phase categories; (1) gaseous, (2) liquid and (3) solid (ETN Global, 2020; Patonia & Poudineh, 2023). The advantages of storing hydrogen in gaseous phase is that it can be used directly by gas turbines and does not have to undergo a process to re-gasify the liquid hydrogen or be separated out of ammonia. Hydrogen in its compressed form makes it readily available for immediate use. However, the energy required to store in compressed form is quite intensive. The storage options for hydrogen can be visualised as shown below in Figure 1.

State of Hydrogen		**Storage Options**		**Transport Options**
Compressed hydrogen		Subsurface gas Compressed hydrogen tanks Pipeline infrastructure		Pipeline Truck
Liquid hydrogen		Liquid hydrogen tanks		Ship
Ammonia		Ammonia tanks		Rail / Barge
Liquid organic hydrogen carrier		Liquid hydrogen tanks		

Figure 1: Options for hydrogen storage and transport (Adapted from ETN Global, 2020, p. 6)

In the context of this article, and because it's low energy density by volume, the most likely short-term storage options include:

- Cylindrical or spherical type pressurised steel containers located above-ground,
- High-strength, lightweight composite fibre storage tanks (Fries, 2021), especially in the case of high-pressure compressed storage,
- Inside suitable existing or new gas pipelines, this is known as ‘linepack’, and
- Located underground in geological formations, such as suitable salt caverns.

For storage in tanks and / or gas pipelines the material composition is important as it affects the integrity. This is a consideration that is not in the scope of this article. In addition, the requirement for high quality freshwater to supply electrolysers will in part dictate the need for short-term storage; similarly, the land needed for electrolysers and whether this land is available at the gas turbine site or ‘over the fence’. That is, the electrolysers could be dispatched as required for generation of hydrogen when the gas turbine is dispatched to supply the grid.

Analysis in this article will be based on the technical characteristics of three GE hydrogen capable industrial (frame) gas turbines[7]:

- GE 9HA02;
- GE 9F05; and the
- GE 9E04.

GE turbines were chosen for analysis because they offer selected industrial scale gas turbines that can support hydrogen capability at 50% or above. On the other hand, Siemens hydrogen-ready gas turbines seem to have a current fuel blend range of between 30% and 50% for industrial scale gas turbines. Some aero-derivative gas turbines from GE and Siemens appear to be able to accommodate high blends or even 100% hydrogen fuel.

The key technical characteristics of the three turbines are presented in Table 1[8]. From Table 1, the 9HA02 turbine can currently support a hydrogen fuel blend of up to 50% and GE states that it has a pathway to 100% hydrogen.[9] The 9F05 gas turbine can currently support a hydrogen fuel blend of up to 80%.[10] The third turbine 9E04 can currently support 100% hydrogen.[11]

[7] https://www.ge.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/products/gas-turbines/9e-fact-sheet-product-specifications.pdf.
[8] Information relating to hydrogen flow rate, emission intensity and percentage reductions in emissions was sourced from the GE hydrogen calculator for the three GE turbines. The GE hydrogen calculator is available at: Hydrogen Calculator: Fuel Costs and Savings | GE Gas Power.
[9] 9HA Gas Turbine | 9HA.01 and 9HA.02 | GE Gas Power.
[10] 9F Gas Turbine | 9F.04 | GE Gas Power.
[11] https://www.ge.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/products/gas-turbines/9e-fact-sheet-product-specifications.pdf.

Table 1. Technical characteristics of selected OCGT (simple cycle) GE gas turbines with hydrogen (H2) capability

GE Turbine / current supported hydrogen (H2) blend rate % in parentheses	Maximum Net Output (MW)	LHV (Low heat value) net heat rate (GJ/MWh)	Supported H2 flow rate (tonnes per hour)	100% H2 flow rate (tonnes per hour)	Emissions intensity at supported H2 blend rates (g/kWh)	(%) emissions reduction at supported H2 blend rates
9HA02 (50% H2)	571	8.166	9.25	38.86	347	23.8
9F05 (80% H2)	299	9.295	13.66	24.42	227	55.9
9E04 (100% H2)	147	9.747	11.94	11.94	0	100.0

From Table 1, examining the characteristics of the 9HA02 turbine, flow rates are non-linear. If the flow rate was linear, moving from 50% to 100% hydrogen would imply a flow rate increasing from 9.25 tonnes to 18.5 tonnes per hour (at 100% hydrogen) instead of the much higher 38.86 tonnes per hour flow rate listed in Table 1. This is also apparent with the 9F05 turbine with the flow rate at 100% hydrogen almost doubling that at 80% hydrogen fuel blend – i.e., from 13.66 (80% hydrogen) to 24.42 tonnes per hour (100% hydrogen). This highlights the practical issue of what quantity and flow rates of renewable hydrogen might be needed to support the use of hydrogen gas blend turbines, particularly if dispatched in a network balancing role.

In addition, comparing the results for the 9HA02 turbine from Table 1, it is not just flow rate that is nonlinear, emissions reductions are also nonlinear. The reduction in emissions (relative to the 100% natural gas case) is only 23.8%, while at 80% hydrogen, the reduction in emissions is 55.9% (see Figure 2). Similarly, for the 9F05 turbine, an 80% hydrogen blend only reduces emissions by 55.9%. For all turbines using 100% hydrogen, the emissions are reduced completely (i.e. 100% reduction). This nonlinear relationship is illustrated in Figure 2 for the GE hydrogen capable 9HA02 gas turbine.

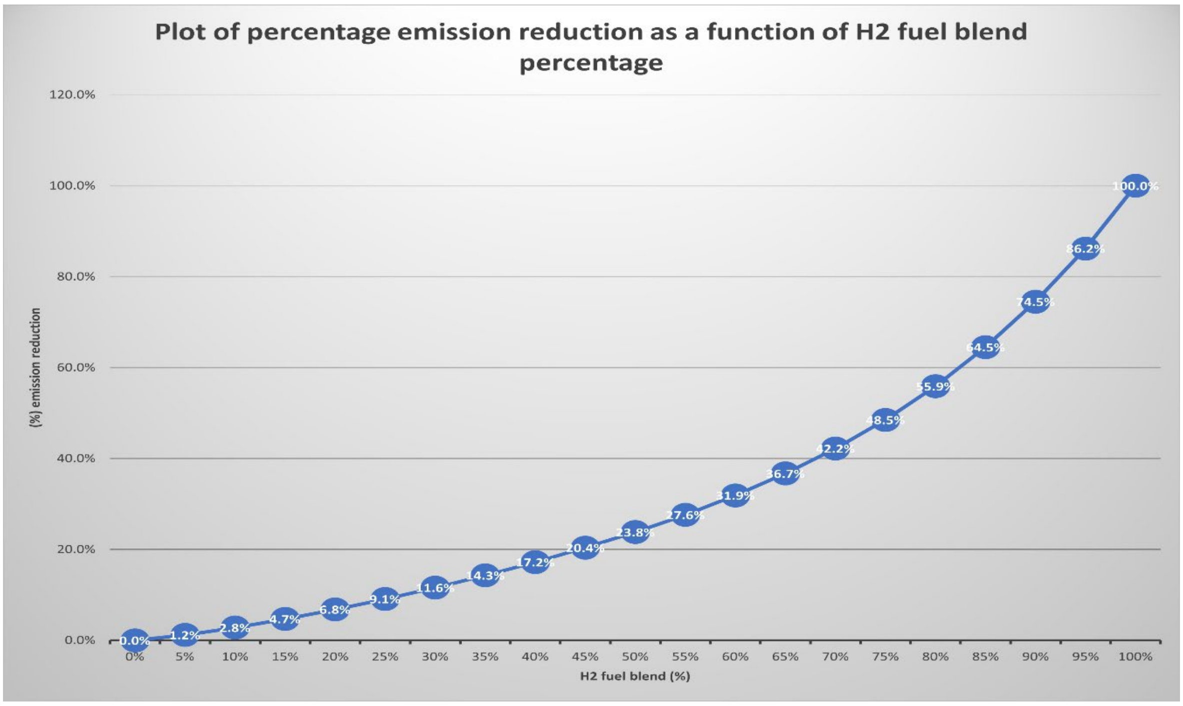

Figure 2. Plot of Hydrogen fuel blend and emission reduction rates for GE 9HA02 hydrogen capable gas turbine

Central to assessment of the applicability of hydrogen gas blend turbines in providing network balancing services are considerations of: (1) the implied fuel cost of using renewable hydrogen [linked to the ($/kg) domestic cost of renewable hydrogen]; and (2) required hydrogen flow rates underpinning both currently supported hydrogen fuel blend rates (where less than 100%) as well as at 100% hydrogen and implied emission reduction rates. In this article, as a case-study, the amount of renewable hydrogen needed to accommodate the dispatch patterns identified in relation to the dispatch of four new OCGT plant obtained from wholesale market modelling will be outlined below.

3. Wholesale Market Modelling Methodology, Data and Assumptions

3.1 ANEM Model

The simulations used in this article to both identify peaking dispatch needs for the electricity grid on the eastern seaboard of Australia and to help enumerate the case-study to be investigated in this article are created from ANEM (Australian National Electricity Market) Model previously built by the researchers [Wild, Bell and Foster (2015) and Bell, Wild, Foster and Hewson (2017)]. This is an agent-based structural model of a power system. Agents include demand- and supply-side participants as well as an Independent System Operator (ISO) who operates and clears the market using Locational Marginal Pricing (LMP). Nodal and transmission line network structures collectively constrain the behaviour of all agents.

ANEM is a modified and extended version of the American Agent-Based Modelling of Electricity Systems (AMES) model developed in (Sun and Tesfatsion, 2007, 2010), and programmed in Java using Repast java toolkit (Repast, 2023; Tesfatsion, 2023). Key features include transmission network pathways, competitive dispatch of generation technologies with price determination based upon marginal costs and branch congestion characteristics, along with intra- and inter-state trade.

A Direct Current Optimal Power Flow (DC OPF) algorithm is used to jointly determine optimal dispatch of generation plant, wholesale spot prices and power flows on transmission branches. Unit commitment features accommodated in the modelling include:

- marginal generation costs;
- capacity (MW) limits applied to both generators and transmission lines;
- generator ramping constraints;
- generator start-up costs; and
- generator minimum stable operating levels.

The optimal dispatch algorithm employed in ANEM is the DC OPF algorithm outlined in Sun and Tesfatsion (2010). The (Mosek, 2023)[12] optimisation software is used to solve the underlying convex quadratic programming problem underpinning the DC OPF solution. The MOSEK software utilises the interior point method and employs sparse matrix methods to significantly speed up solution times.

The base model assumptions relating to ($/MW/year) Fixed Operation and Maintenance (FOM) costs, ($/MWh) Variable Operation and Maintenance (VOM) costs, ($/GJ) fuel cost, minimum and maximum MW capacities, auxiliary load rates, emission intensity rates and plant closures were sourced from the Australian Energy Market Operator's (AEMO, 2022) biannual Integrated System Plan or 'ISP' assumptions and scenarios workbook v3.4 dated June 2022'.[13] We particularly follow the AEMO assumptions for the 2022 ISP associated with their so-called '2030 step-change' scenario. The detailed ANEM model structure used in the wholesale market modelling incorporated 415 generators, 86 transmission lines and 59 nodes located within five zonal regions linked to the five State jurisdictions comprising the NEM.

3.2 Application of pumped hydro and batteries

Pumped-hydro (PHES) and battery (BESS) technologies undertake a nuanced role in the market given their ability to absorb otherwise 'excess output' from intermittent solar PV and wind generation. In the modelling, pumping or charging loads of both pumped-hydro and batteries were targeted towards periods where the underlying variable renewable energy (VRE) resources were sufficient to supply both underlying aggregate demand as well as additional demand created through pumping or charging loads. By linking pumping and charging loads to periods of high VRE resource availability, it is more likely that sufficient generation output will be available to meet aggregate underlying demand and storage loads,

[12] Mosek version 6 was used within the ANEM model to obtain the results reported in this paper.
[13] All data is available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

thus minimising the potential incidence of higher wholesale electricity prices at the margin. The key rationale for this approach is that the higher the amount of renewable energy available for dispatch, the lower will be the resulting spot price, ceteris paribus.

In the ANEM model, the PHES and BESS supply offers generally fall between coal and OCGT plant pricewise, targeting a balancing roll but with a competitive advantage relative to OCGT technologies. This strategy has two facets: (1) it maximises the roll that storage technologies can contribute to system balancing; and (2) it determines the minimum sizing of gas generation capacity that might be needed for system balancing purposes. This potential role that gas could play as a balancing resource might become more salient in the context of: (1) increased coal plant closures; (2) increasing levels of VRE for base energy supply; and (3) an emerging reliance of storage technologies (both PHES and BESS) on intermittent VRE energy sources to charge batteries or pump water.

3.3 Gas turbines

To investigate OCGT's role in system balancing and later test whether hydrogen capable OCGT are feasible, in the modelling four new OCGT plant were included in the simulations located at the Central West Queensland (CWQ), Gladstone, Tarong and Moreton South (MS) nodes in Queensland. These four gas turbines were subsequently termed CWQ GT, GLAD GT, TARONG GT and MS GT. These four gas plants were assumed to have a maximum capacity of 724 MW each and under default model settings, were bid in at a short run marginal cost (SRMC) of $300/MWh (or higher). At these supply offer levels, the four plant would be much more expensive than PHES, BESS or existing gas plant [whether natural gas combined cycle (NGCC) or OCGT]. As such, the four new gas plant would be dispatched after PHES, BESS and existing gas plant. Therefore, they take on a last resort status to be dispatched only after other available generation resources had been exhausted within the modelling environment. This aligns with QEJP requirements of reducing the use of natural gas.

The maximum combined capacity of the four new OCGT is 2894MW [comprising 3 x 724MW at CWQ, Gladstone and Tarong and 1 x 722MW at MS] from a total combined QLD MW gas capacity of 6176 MW, including both existing NGCC and OCGT plant. To examine the issue of how the four new gas turbines might be used in network balancing and enumerate the case-study (e.g., understand the quantity and flow rates of the hydrogen required assuming H2 capable gas turbines instead of standard OCGT turbines), we use the simulated dispatch patterns of the four OCGT plant obtained from the modelling which will be discussed below.

3.4 Scenario parameters

The results reported in this article were obtained from running the ANEM wholesale electricity market model across five scenarios (A to E). In all modelled scenarios (A to E) considered in this article, an aggregate QLD GT capacity of 6176 MW is assumed to be available, comprising 1455 MW of existing NGCC capacity, 1827 MW of existing OCGT capacity and 2894 MW of new build OCGT capacity. The following coal closures were also assumed:

- Queensland: Callide B, Gladstone, 1 unit of Stanwell and four units of Tarong[14];
- New South Wales: Liddell, Eraring and Vales Point; and
- Victoria: Yallourn and Loy Yang A.

The other parameters for each scenario are outlined in Table 2. In the scenarios considered in this article, two sensitivities were investigated. The first relates to whether two proposed PHES plant (i.e. Lake Borumba and Pioneer) were operational[15]. The second relates to whether the four new OCGT plant were dispatched at their default supply offer (i.e., at $300/MWh) or at a much lower rate ($130/MWh) which matched the supply offers assumed for existing OCGT plant in Queensland.

Table 2. Scenario parameters

Scenario	PHES (Lake Borumba and Pioneer)	Gas price supply offer	PHES Pump Action
A “no Phes, GPlow”	Not operational	Low: $130/MWh	NA
B “Phes / GPlow, default pump”	Operational	Low: $130/MWh	Default settings
C “no Phes,GPdefault,”	Not operational	Default: $300/MWh	NA
D ”Phes, GPdefault, default pump”	Operational	Default: $300/MWh	Default settings
E ”Phes, GPdefault, enhanced pump”	Operational	Default: $300/MWh	Enhanced setting

3.5 The role of gas in network balancing

Notwithstanding the higher default gas price supply offers, all four new build OCGT plant (e.g., CWQ GT, GLAD GT, TARONG GT and MS GT) were dispatched at different levels across the scenarios considered, indicating an expanded role for gas (in addition to existing GTs). This is in terms of both energy and capacity in contributing network balancing services. An example of a typical dispatch pattern across the aggregated four new OCGT plant for the default gas price of $300/MWh and no PHES (scenario C) is presented in Figure 3. This shows the OCGT is dispatched outside the peak solar periods, with most generation between 6pm and 9pm to cover the evening peak. Similarly, an example of a typical dispatch pattern for the low gas price option of $130/MWh with no PHES (scenario A) across the aggregated four new OCGT plant is shown in Figure 4. Figure 4 illustrates the impact of the lower gas price with the OCGT being deployed more often with the evening peak dispatch time now extending from 6pm out to 11:30pm and significant gas turbine dispatch in the morning as well. In Figure 4 (scenario A) the OCGT are dispatched even in peak solar times (10am – 3pm) due to the lower gas price offering.

[14] Note, Tarong North was assumed to be operational in all modelled scenarios.

[15] In the modelling, Pioneer refers to a PHES located in North Queensland. The maximum capacity of 1.5 GWs is assumed which is significantly lower than the Pioneer PHES proposal identified in the Queensland Energy Plan which, upon full construction, would be 5 GWs.

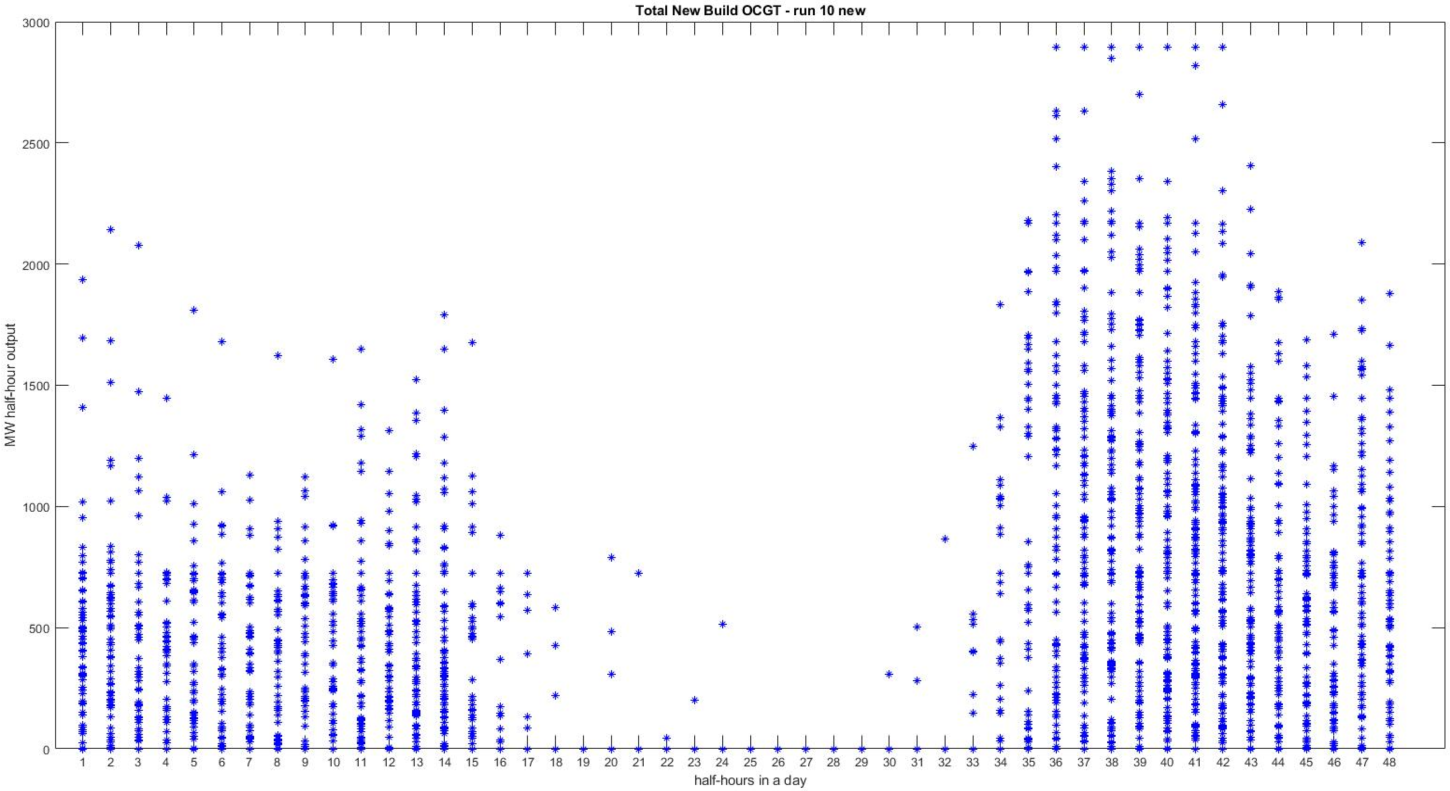

Figure 3. Typical dispatch pattern for aggregated four new build OCGT plant for default supply offer of $300/MWh: with Lake Borumba and Pioneer PHES assumed not operational (scenario C)

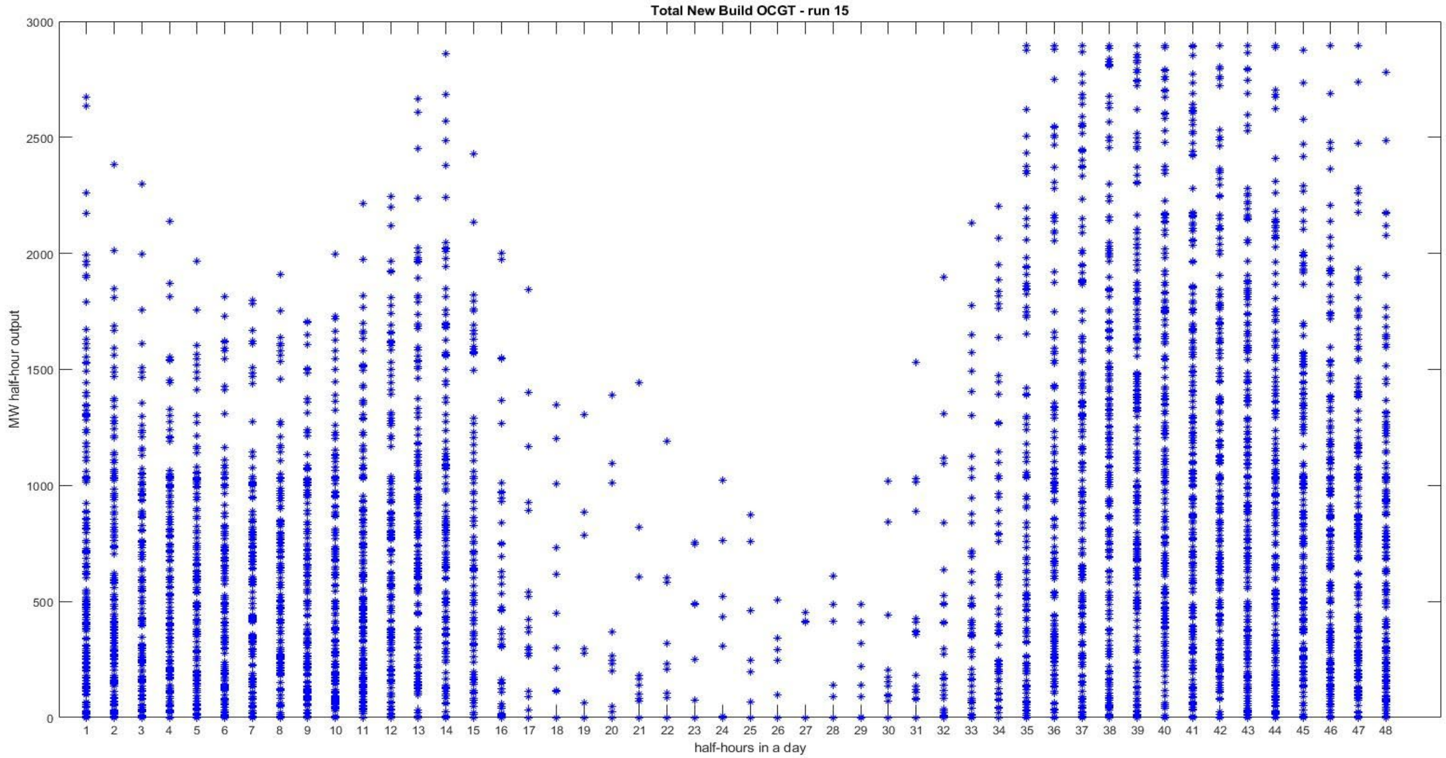

Figure 4. Typical dispatch pattern for 4 new build OCGT plant for low gas price supply offer of $130/MWh with Lake Borumba and Pioneer PHES assumed not operational (scenario A)

In both Figures above, higher dispatch intensities principally arise over-night (especially during the evening peak) than during the day although Figure 4, comparatively, has more intensive dispatch patterns during the day compared with Figure 3. The other key result to note is that in both cases, all four new OCGT plant are sometimes dispatched together at the same time, representing an aggregate combined capacity of 2894 MWs at those times. This outcome extends generally to all scenarios considered in this article.

The lower dispatch levels observed during the day reflects the excess supply of rooftop solar. Ultimately, aggregate final demand is not falling, the grid-supplied element of it is, arising from an emergent duck curve effect. This is depicted in Figure 5 below which plots the 2022 ISP 2030 Queensland operational demand corresponding to the step-change scenario[16]. This demand data exhibits a wide dispersion of demand outcomes during the day, in the range of 1422 MWs to a touch over 8000 MWs. This contrasts with overnight demand which is much more tightly concentrated and significantly higher than a large portion of daytime demand. The highest level of demand falls during the evening peak with the highest value being 10894 MWs.

[16] Operational demand can be interpreted as the demand that has to be met from centralised generation after distributed behind the meter sources of demand have been subtracted from gross demand.

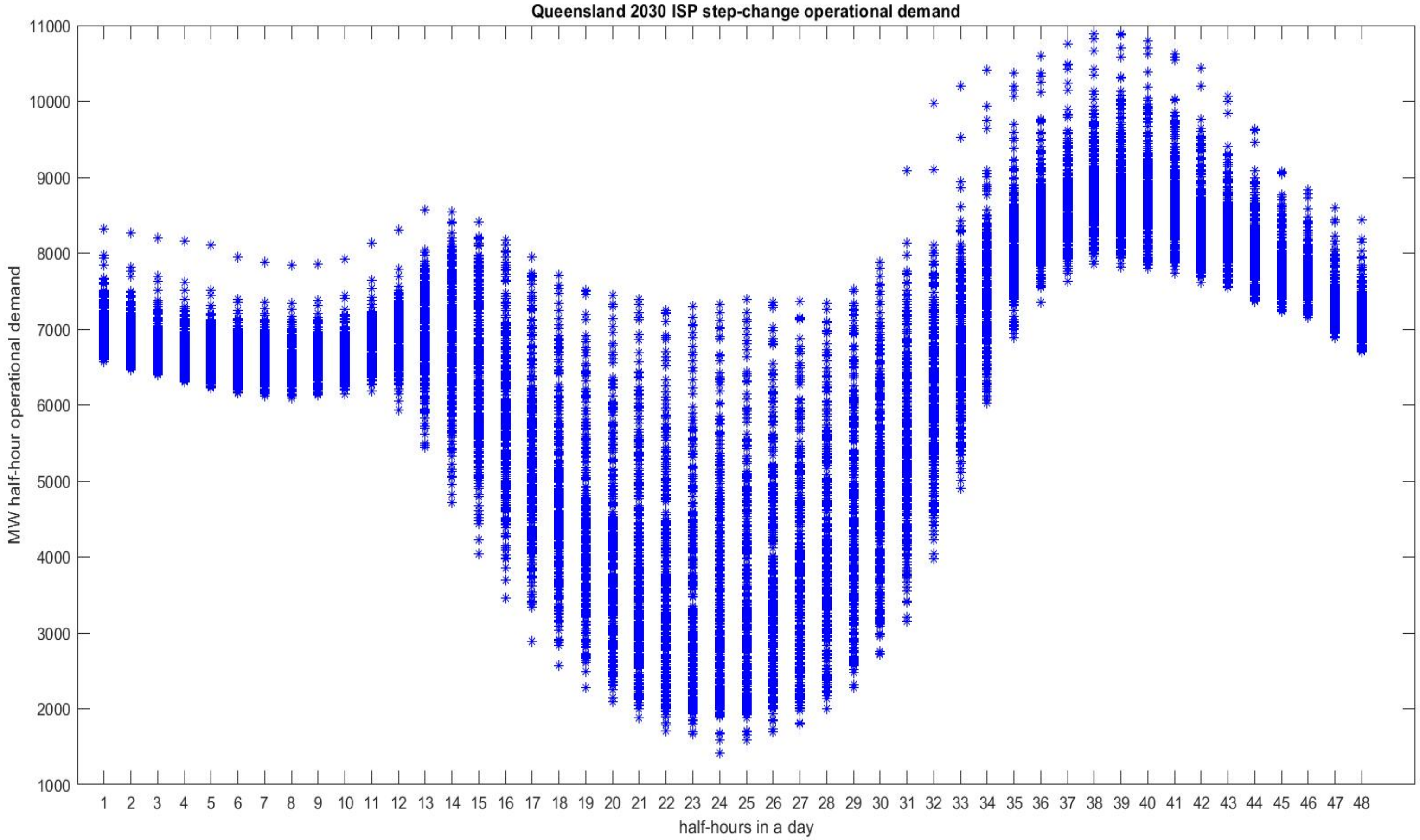

Figure 5. 2030 Queensland operational demand – ISP 2022 step-change scenario

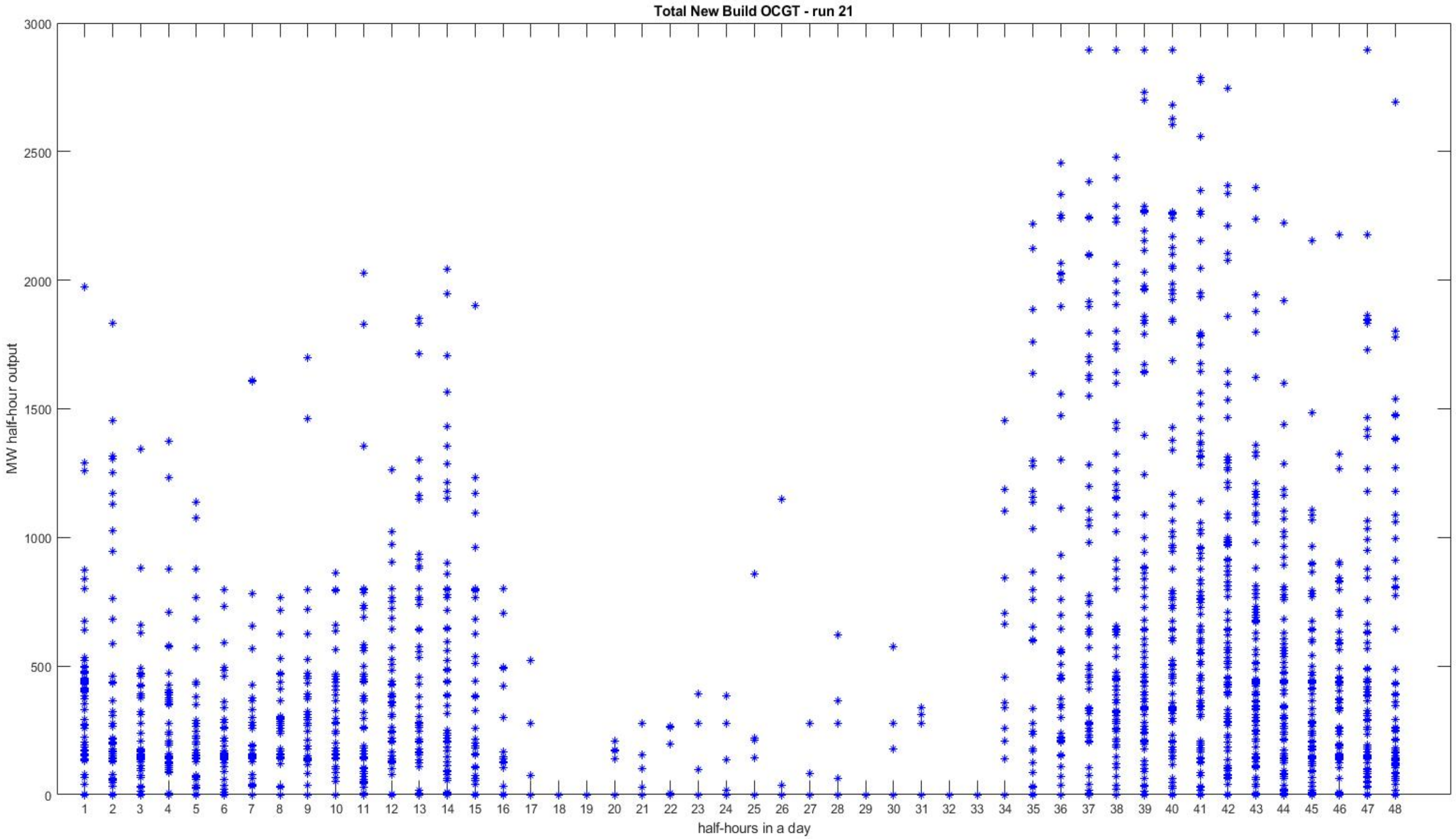

Figure 6. Typical dispatch pattern for aggregated four new build OCGT plant for default supply offer of $300/MWh: with PHES (Lake Borumba and Pioneer) operational with default pump actions – scenario D)

Figure 6 provides an example of a typical dispatch pattern across the aggregated four new OCGT plant for the default gas price of $300/MWh but now with the two PHES plants being operational. This results in considerably less gas turbine dispatch throughout the whole day with the evening peak dispatch shorter from 6:30pm to 8pm. This situation clearly contrasts with that in Figure 3 where the evening peak gas turbine dispatch extended from 6 - 9pm. The dispatch patterns denoted in Figure 6 are less intensive than in Figure 3, especially during overnight hours and during the evening peak. However, there is a slight uptick in dispatch in Figure 6 during daytime hours, most likely reflecting additional dispatch of the OCGT plant, at the margin, to support pump actions during daytime by the now operating PHES units. Thus, the introduction of PHES, in total, reduces the extent of dispatch of the four new OCGT plant.

This observation is confirmed by examining the Annual Capacity Factors (ACFs) of these four OCGT plant by scenario. This is documented in Table 3. The impact of reduction in gas turbine dispatch following the introduction of the PHES units is most clearly shown in the reduction in ACFs of all four OCGT plant under Scenario B (with PHES) compared to Scenario A (no PHES) and for CWQ GT and TARONG GT in Scenario D (PHES, and default pump) relative to Scenario C (no PHES). The uptick in ACFs between Scenario C and Scenario D observed for GLAD GT and MS GT reflects the need for additional dispatch of this plant to support, at the margin, pump actions by the PHES plant in Scenario D. This is because Gladstone and Moreton South nodes share transmission interconnection directly with the nodes containing the PHES units whilst also containing significant operational loads themselves.

Comparison of the reduced ACFs across all four OCGT plant running on natural gas under Scenario E (PHES operational with enhanced pumping) relative to Scenario D (PHES, and default pump) indicates that more aggressive pump actions by the PHES will further reduce the dispatch of the OCGT plant. This is because the more aggressive pump actions allows more energy to be stored and made available for dispatch by the PHES units, thereby crowding out the dispatch of the gas turbines as PHES is offered more cheaply than the gas turbines.

Table 3. ACFs of four new OCGT plant by modelled scenario

Scenario	Central West Qld GT	Gladstone GT	Tarong GT	Moreton South GT
A “no Phes, GPlow”	6.58%	6.97%	6.37%	13.38%
B “Phes / GPlow, default pump”	4.18%	4.44%	4.59%	9.48%
C “no Phes, GPdefault,”	11.41%	0.16%	3.06%	0.80%
D ”Phes, GPdefault, default pump”	0.96%	1.21%	0.99%	4.68%
E ”Phes, GPdefault, enhanced pump”	0.78%	0.97%	0.81%	3.64%

Another key consideration, given the current focus on transitioning to a 2050 zero net emission world, is: (1) what level of emissions are produced by the new OCGT plant; (2) how do emission outcomes depend upon bidding assumptions applied to new OCGT units; and (3) what impact does the introduction of the two PHES units have on the emissions of the OCGT units. These results can be discerned from Table 4.

Table 4. Emissions of four new OCGT plant by modelled scenario in Mt C02-e when using 100% natural gas

Scenario	Central West Qld GT	Gladstone GT	Tarong GT	Moreton South GT	Total
A “no Phes, GPlow”	0.40	0.42	0.36	0.43	1.60
B “Phes / GPlow, default pump”	0.25	0.27	0.26	0.30	1.08
C “no Phes, GPdefault,”	0.69	0.01	0.17	0.03	0.89
D ”Phes, GPdefault, default pump”	0.06	0.07	0.06	0.15	0.34
E ”Phes, GPdefault, enhanced pump”	0.05	0.06	0.05	0.12	0.27

In this table, the Mt C02-e results are listed by scenario for each of the four OCGT plant individually running on pure natural gas as well as a total ‘portfolio’ result listed in the last column, compiled by aggregating across the four OCGT plants. The highest emission outcomes are recorded for Scenario A as no PHES units are operating and gas price is low, prompting greater dispatch of the four GT units. For this scenario, the individual plant outcomes are in a range between 360 000 tonnes for Tarong GT and 430 000 tonnes of C02-e for Moreton South GT and with the total across all four units being 1.6 million tonnes of C02 (Mt C02-e) in annualised terms. The next largest level of emissions corresponds to Scenario B where while there are PHES units operational gas price is low, with an aggregate level of emissions of 1.08 Mt C02-e. In aggregate terms, these two sets of results exceed those associated with Scenarios C, D and E listed in Table 4. The main factor producing the higher levels in Scenarios A and B relates to the much cheaper gas supply offers (at $130/MWh) relative to the much higher supply offers of $300/MWh associated with Scenarios C, D and E.

The introduction of the two PHES units reduce emissions across the four new OCGT plant when they are operating with 100% natural gas. This can be seen by comparing the results of

Scenario B (with PHES) against the results of Scenario A (without PHES) *but with the same supply offer structures*. This can also be seen in the aggregate results for Scenario C (no PHES) and Scenario D (with PHES). Note again that there is some variation about this theme between individual OCGT plant, as was also observed in Table 3 in relation to ACFs. Finally, comparison of Scenario E (more aggressive pump actions) with Scenario D [default (less aggressive) pump actions] indicates that more aggressive pump actions by the PHES plant can reduce the levels of emissions across the four individual OCGT plant as well as the total 'portfolio' results presented in the last column of Table 4.

In a 2050 zero net emission world, it is likely that emission produced by the OCGT plant would need to be offset by some certificate scheme that employs a carbon price to offset emissions. This would impose a cost on the owners of such plant. For example, using the aggregate 'portfolio' emission outcomes listed in the last column of Table 4, a $30/tC02-e carbon price would produce a cost impost of between $8.1 million (Scenario E) and $48 million (Scenario A). Similarly, for a carbon price of $100/tC02-e, this would imply a higher cost impost of between 27 and 160 million dollars. As such, these costs accruing to the owners of the new OCGT plant might provide a strong motivation to further de-carbonise their operations to avoid, or at least, minimise this additional cost.

One option might be to invest in a carbon capture and storage (CCS) solution although a disadvantage of this option is the length of time that carbon emissions would have to be sequestered underground (as well as a financial and legal risks associated with leakage from underground storage caverns) and land area required (Ren. et al 2022). Another newer and emerging option would be to use an open cycle hydrogen capable gas turbine (OCHGT) plant co-fired with hydrogen. This option will be investigated in the following section as a case-study where we will examine the underlying H2 requirements of the three GE OCHGT's that are needed to produce the dispatch patterns of the four new OCGT plant that were highlighted above.

4. Case-study: Results of Hydrogen capable gas turbines (OCHGT)

Recall from the discussion in the Literature Review Section that two factors were identified as central to assessment of the applicability of hydrogen gas blend turbines in a network balancing role: (1) the implied fuel cost of using renewable hydrogen [linked to the ($/kg) domestic cost of renewable hydrogen]; and (2) required hydrogen flow rates underpinning both currently supported hydrogen fuel blend rates (where less than 100%) as well as at 100% hydrogen and implied emission reduction rates.

To investigate these aspects further, the MW dispatch patterns identified in the previous section associated with the four new OCGT turbines will be used to underpin assessment of renewable hydrogen requirements needed with the assumed use of the three GE hydrogen capable gas turbines. To facilitate this discussion, the next sub-section will outline two measures of hydrogen requirement. This will be followed by assessment of fuel and production cost equivalence, followed by assessment of hydrogen requirement. This will, in turn, encompass investigation of: (1) annual requirement (in tonnes of H2); and (2) short-term storage requirements. Finally, the nature of emission reductions associated with the use of OCHGT will also be documented.

4.1 Hydrogen requirement measurement methodology

Two measures of hydrogen requirements are investigated. The first, termed 'scaling', provides an estimate of renewable hydrogen needed to satisfy the dispatch patterns associated with each of the new OCGT plant identified in the previous section. This means scaling up the capacity of the hydrogen capable OCHGT plant to match the modelled dispatch levels if they exceed the maximum capacities of the three GE turbines selected. Recall that this scaling up would arise if the maximum capacity at peak dispatch times required of the four new OCGT plant in the modelling is say 724 MW which exceeds the maximum capacities of the three GE hydrogen capable OCHGT turbines [i.e., 9HA02 with 571MW, 9F05 with 299MW, and 9E04 with 147MW (see column 2 of Table 1)].

The second measurement method is called 'whole gt'. This provides an upper range estimate of hydrogen requirements for fully flexible dispatch by the turbines. This method assumes that the three GE turbines cannot be automatically scaled to achieve higher dispatch targets. Instead, if a dispatch target exceeds the maximum capacity of a nominated GE turbine, an additional turbine would have to be installed to enable achievement of the dispatch targets. For example, if the dispatch target was 1.5 times the maximum capacity of one of the GE turbines, then <u>two</u> GE turbines would be needed. If the dispatch target was 2.2 times the capacity of the GE turbine, then <u>three</u> GE turbines would be needed.

Given the maximum capacity of the modelled new OCGT plant was 724 MW, and the maximum capacities of the three GE OCHGT turbines listed in Table 1, the multiples to achieve 724 MWs is 1.27 for 9HA02, 2.42 for 9F05 and 4.93 for 9E04 turbine. Therefore, under the 'whole gt' method, to achieve the maximum modelled dispatch capacities would require installation of <u>two</u> 9HA02 turbines, <u>three</u> 9F05 turbine and <u>five</u> 9E04 turbines for each new OCGT plant identified in the previous section. Furthermore, assuming full dispatch flexibility for each installed GE turbine would require that each turbine has access to sufficient renewable hydrogen necessary to dispatch each installed turbine at its maximum capacity as listed in Table 1. Thus, the renewable hydrogen requirements under the 'whole gt' method, would exceed the requirements needed to strictly achieve the modelled dispatch patterns (as estimated under the 'scaling' method) but would be sufficient to enable the dispatch of all the installed OCHGT turbines up to their maximum MW capacity.

4.2 Fuel and production cost equivalents

The first key issue identified above from the Literature Review was the cost equivalence between the domestic cost of production of renewable hydrogen [on a ($/kg) basis], its equivalent fuel cost on a ($/GJ) basis for power generation applications and the implied SRMC of the plant (also for power generation). This data is reported in Table 5. It should be noted that some 2022 ISP assumptions were employed in compiling short run marginal costs (SRMC) estimates relating to Variable Operations and Maintenance (VOM) costs on an energy generated basis equal to $2.52/MWh and auxiliary usage set to 1.1%. Each GE turbine's respective Lower Heat Value (LHV) net heat rate (GJ/MWh) in column 3 of Table 1 were also used in compiling the SRMC estimates. Variations in this parameter associated with the different gas turbines identified in Table 1 was responsible for producing the variations in SRMC estimates associated with each turbine outlined in Table 5.

Table 5. Comparative assessment of hydrogen (H2) ($/kg) production costs, ($/GJ) fuel costs and ($/MWh) SRMC

H2 production cost ($/kg)	Implied fuel cost ($/GJ)	9HA02 SRMC ($/MWh)	9F05 SRMC ($/MWh)	9E04 SRMC ($/MWh)
		50% H2	80% H2	100% H2
6.00	50.00	410.82	467.27	489.87
5.00	41.67	342.77	389.81	408.64
4.00	33.33	274.72	312.35	327.42
3.00	25.00	206.67	234.89	246.19
2.00	16.67	138.62	157.43	164.97
1.50	12.50	104.59	118.71	124.36
1.00	8.33	70.57	79.98	83.74

Current estimates of the domestic cost of renewable hydrogen are thought to be between $5/kg and $6/kg. From Table 5, these cost levels produce equivalent ($/GJ) fuel costs between $41.67/GJ and $50/GJ and with implied SRMC's in the range of $342.77/MWh to $489.87/MWh, depending on the turbine. It should be noted that even with these very high ($/GJ) gas prices (at least by historical standards and ignoring the turmoil in Quarters two and three of 2022), the SRMC estimates are typically in the range that would shadow diesel generation in the NEM[17].

The Commonwealth Government recently announced in the 2023 Federal Budget a programme called the Hydrogen Headstart Initiative which was established to provide a $2 billion revenue support program for large scale green hydrogen projects. This programme is to be developed by ARENA.[18] This program is expected to apply a project specified subsidy to selected projects which would effectively reduce their near-term domestic production costs and bring it in line with expected off-take prices, accommodating an allowance for a return on capital on the part of domestic producers of renewable hydrogen. If the production subsidy was $2/kg, this would bring the domestic production cost down to between $3/kg and $4/kg

[17] In the AEMO 2022 ISP input assumptions and scenarios workbook, the two Queensland diesel peak generators had SRMC of $478.17/MWh (MacKay) and $447.34/MWh (Mt Stuart). A number of other diesel plant in South Australia had similar supply offers, in the range $480.18/MWh and $505.00/MWh (e.g. Port Lincoln, Snuggery and Angaston power stations). Interestingly, two South Australian diesel plant had significantly lower supply offers of $301.63/MWh (e.g. Lonsdale and Port Stanvac).
[18] https://arena.gov.au/news/2-billion-for-scaling-up-green-hydrogen-production-in-australia/.

for successful projects. In this case, from Table 5, this would reduce the ($/GJ) fuel cost to between $25/GJ and $33.33/GJ and the SRMC to between $206.67/MWh and $327.42/MWh, again depending on the turbine. In respect to the latter results, SRMC of hydrogen gas generation would clearly fall between that of conventional OCGT and diesel generation in the NEM.

The longer-term target for Australia and many other international jurisdictions appears to be $2/kg with an implied ($/GJ) fuel cost of $16.67/GJ which is broadly consistent with spot gas prices applicable to open cycle gas turbines currently. A domestic cost of production of ($1/kg) would produce a ($/GJ) fuel cost of $8.33/GJ, consistent with equivalent average gas prices arising over the last decade and a half. Moreover, a production cost of $1.5/kg would produce a ($/GJ) cost just above the $12.00/GJ range of the current cap on spot gas prices introduced late 2022 in response to the gas price shocks that arose over quarters two and three of 2022.

For completeness, given the successful dispatch of the four new OCGT plant at default SRMC supply offer of $300/MWh outlined in the previous section, the equivalent hydrogen productions costs and equivalent ($/GJ) fuel costs were determined for each of the GE gas turbines. These results are reported in Table 6 and show domestic production costs of between $3.66/kg and $4.37/kg and between $30.53/GJ and $36.43/GJ to achieve a $300/MWh SRMC target for each GE turbine.

It should be noted how the thermal efficiency of the respective GE hydrogen capable gas turbines, as denoted by the LHV net heat rate in Table 1, influences the attainment of the $300/MWh SRMC target. The 9HA02 turbine has the best efficiency (implied by a lower net heat rate value in Table 1) and has the highest production ($/kg) and fuel cost ($/GJ) rates listed in Table 6 consistent with the $300/MWh SRMC target, relative to the other two listed turbines. This implies that at the ($/kg) and ($/GJ) rates of the other two turbines, the SRMC of the 9HA02 turbine would be *well below* the $300/MWh SRMC target as also borne out in Table 1. Similarly, the 9F05 gas turbine is more efficient than the 9E04 turbine and would have a SRMC less than the $300/MWh target at the ($/kg) and ($/GJ) rates associated with the 9E04 turbine listed in Table 6.

Table 6. ($/kg) Hydrogen production costs and ($/GJ) fuel costs consistent with ($300/MWh) SRMC

	9HA02	9F05	9E04
($/kg) Hydrogen production cost	4.37	3.84	3.66
($/GJ) equivalent fuel cost	36.43	32.00	30.53

4.3 Annual hydrogen requirement

The aggregate annualised hydrogen requirements (in tonnes) of the modelled dispatch patterns of the four new OCGT plant (identified in the previous section) under both the 'scaling' and 'whole gt' measurement methods, utilising the three GE OCHGT turbines, are reported in Table 7. The results in Table 7 are compiled by summing across the four new

OCHGT plant results to derive the aggregate annualised results. The individual plant-based results are listed in Appendix A.

Table 7. Annualised renewable hydrogen (H2) usage by turbine and scenario (tonnes)

Scenario	H2 blend	9HA02	9HA02	H2 blend	9F05	9F05	H2 blend	9E04	9E04
	%	scaling	whole gt	%	Scaling	whole gt	%	scaling	whole gt
A "no Phes, GPlow"	50%	34,187	96,851	80%	96,376	176,870			
	100%	143,558	406,693	100%	172,311	316,228	100%	171,345	234,016
B "Phes / GPlow, default pump"	50%	23,295	75,116	80%	65,669	132,315			
	100%	97,819	315,423	100%	117,411	236,566	100%	116,752	168,423
C "no Phes, GPdefault"	50%	15,864	29,739	80%	44,721	62,777			
	100%	66,615	124,879	100%	79,957	112,239	100%	79,509	89,602
D "Phes, GPdefault, default pump"	50%	8,050	21,634	80%	22,695	40,540			
	100%	33,805	90,843	100%	40,576	72,482	100%	40,348	53,785
E "Phes, GPdefault, enhanced pump"	50%	6,362	16,924	80%	17,934	31,894			
	100%	26,715	71,065	100%	32,065	57,023	100%	31,885	42,204

The maximum annualised hydrogen requirement under the 'scaling' method was 172,311 tonnes corresponding to turbine 9F05 (for 100% hydrogen fuel blend) and Scenario A (no PHES). The largest hydrogen requirements across the GE turbines at currently supported hydrogen fuel blend rates also arise in Scenario A in the range 34,187 (9HA02 @ 50% hydrogen) to 171,345 (9E04 – 100% hydrogen). These requirements increase significantly under the same scenario for 100% hydrogen encompassing 143,558 (9HA02) to 172,311 (9F05) tonnes. Note that under the 'scaling' method, the 9HA05 turbine is the most efficient turbine, requiring the lowest aggregate amount of renewable hydrogen to support the modelled dispatch patterns at 100%.

In contrast, the largest hydrogen requirement under the 'whole gt' method was 406,693 tonnes associated with the 9HA02 turbine (@100%) under Scenario A (no Phes with low gas price). The largest hydrogen requirements under the 'whole gt' method continue to be associated with Scenario A. At currently supported hydrogen fuel blend rates, the required hydrogen was 96,851 (9HA05 @ 50%), then 176,870 (9F05 @ 80%) and then 234,016 (9E04 @ 100%) tonnes. These requirements increase significantly at 100%, encompassing 234,016 (9E04), 316,228 (9F05) and finally 406,693 (9HA02). Unlike the 'scaling' method, the larger MW capacities of 9HA02 when combined with the fully flexible operational assumption produces a significant increase in required hydrogen relative to the other two turbines. This process also drives the increase in hydrogen requirements of 9F05 relative to 9E04 (e.g. 316,228 versus 234,016 tonnes).

Comparison of Scenario B (with PHES) with Scenario A (no PHES) shows that the addition of the two PHES units (Lake Borumba and Pioneer) reduces the amount of renewable hydrogen required relative to Scenario A at both currently supported hydrogen blend rates and at 100% hydrogen. For example, for the scaling method, at 100%, the hydrogen requirement of the 9HA02 turbine declines from 143,558 tonnes (under Scenario A – PHES not included) to 97,819 tonnes under Scenario B (PHES now included). In the case of the 'whole gt' measurement method, at 100% hydrogen, the requirement of the 9HA02 turbine declines from 406,693 tonnes of hydrogen (under Scenario A) to 315,423 tonnes under Scenario B. This trend, more generally, extends across all three turbines and across all modelled scenarios considered.

Comparing the results from Scenario A with those of Scenario C shows how the hydrogen requirement associated with then less intensive dispatch under the higher default gas supply offers of $300/MWh (i.e. Scenario C) also declined relative to more intensive dispatch under cheaper supply offers (i.e. $130/MWh) associated with Scenario A. Specifically, at 100% hydrogen, the hydrogen requirements declines from 143,558 tonnes (Scenario A) to 66,615 tonnes (Scenario C) under the scaling method, and from 406,693 to 124,879 tonnes of hydrogen for the 9HA02 turbine under the 'whole gt' measurement method. Similar outcomes arise for the other two GE turbines. Thus, the addition of the two PHES units *significantly* reduces the amount of renewable hydrogen needed to underpin the dispatch of the four new OCHGT plants in a network balancing role.

Comparing the results of Scenario D with Scenario E also shows how underlying hydrogen requirements continue to diminish further with more aggressive pump action by the PHES units in Scenario E relative to Scenario D. The lowest hydrogen requirements are recorded under Scenario E which involves a combination of: (1) high gas supply offers; (2) operational PHES; and (3) enhanced pump actions by those PHES units. Under this scenario, the hydrogen requirements are in the range of 6,362 to 32,065 tonnes of under the 'scaling' method, and between 16,924 to 71,065 tonnes of hydrogen under the 'whole gt' method, with outcomes also depending on the hydrogen fuel blend rate.

More generally, inspection of Table 7 conveys a number of broad results, including *significantly higher* hydrogen requirements:

- associated at 100% hydrogen relative to requirements at currently supported hydrogen blend rates (i.e., 50% for 9HA02 and 80% for 9F05);
- under the 'whole gt' measurement method relative to 'scaling' method;
- under scenarios Scenario A and Scenario B associated with the dispatch of OCHGT plant at lower gas supply offers of $130/MW; and
- when the two PHES plant (i.e. Lake Borumba and Pioneer) are *not operational*, for example, compare the results of Scenario A against Scenario B and Scenario C with Scenario D.

In contrast, *significantly lower* hydrogen requirements emerge if: (1) the gas plant are bid in at their higher default ($300/MWh) supply offer values; and (2) the two PHES plant *are operational* – PHES operates to crowd out some dispatch of the four new OCHGT plant at the margin, reducing underlying hydrogen requirements, which is also enhanced further under more aggressive pump actions on the part of the PHES units, i.e. comparing Scenario E with D.

4.4 Short-term storage requirement

Two approaches are currently employed by gas and diesel generators in the NEM to store short-term quantities of gas and diesel needed to facilitate the provision of peak load production duties. These methods are:

- Linepack – storage of gas in local pipes supplying gas to the turbines (subject to the pipe material compatibility to store high percent of hydrogen blend)[19]; and
- Onsite storage tanks (either compressed hydrogen or liquid form such as ammonia).

If it is assumed that hydrogen blend turbines will operate in a similar manner to how gas turbines currently operate in the NEM[20], the gas supply contract will depend on whether the hydrogen capable gas plant is offering intermediate or peak production duties. If the latter case, the contract will have a smaller volume and a price premium relative to larger gas volumes contracted for intermediate production duties. In the case of peak load plant aligned

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[19] According to Advisian (2022) the storage quantities for kilometre (km) of linepack can vary from 4.8 t H_2 per km for purpose-built pipe to 2.1 t H_2 per km for existing pipe (dependant on the condition of existing pipe).

[20] Specifically, generators will contract for a given amount of hydrogen that is to be delivered from the main hydrogen pipeline network to their site by local dedicated pipeline infrastructure that defines line pack characteristics (and potentially the need for onsite storage tanks).

to providing network balancing services, if their use of hydrogen exceeds the volume of hydrogen contracted for, they would have to source additional hydrogen volumes from the spot market, potentially at a price that might significantly exceed their contracted prices.

Additional considerations emerge in relation to utilisation of hydrogen capable turbines. These would include:

- Assessment of the volume of renewable hydrogen needed to cover potential dispatch patterns over the short-term;
- Examination of whether decarbonisation trends (e.g. coal plant closures and significantly increased penetration of VRE) are increasing the requirements for network balancing services which might increase the volume of natural gas or renewable hydrogen needed to fulfill this role in the future; and
- Accounting for the increase in volumes of hydrogen likely to be needed relative to that of natural gas as the significantly lower hydrogen density implies the need, in volume terms, of three times as much hydrogen as natural gas.

These three broad considerations underpin the analysis of the key issue of the short-term storage requirements (in terms of tonnes of H2) needed to meet the dispatch obligations of the hydrogen capable gas turbines. To assess this aspect, we investigate the maximum amount of renewable hydrogen that would be needed to meet the aggregate dispatch patterns of the four new OCHGT plant. We focus on maximum short-term hydrogen requirements associated with each specific GE gas turbine, modelled scenario and measurement method (e.g. 'scaling' or 'whole gt') relating to a:

- single day interval;
- two consecutive day interval; and
- seven consecutive day intervals.

These aggregate storage requirements are calculated by adding together the maximum storage requirements over the three above-mentioned intervals for each of the four new modelled OCHGT plant which are then summed together to calculate the aggregate results across the four OCHGT plants. These aggregated results are outlined in Table 8, whilst for completeness, the individual plant results are presented in Appendix B.

Examination of Table 8 indicates that the highest short-term storage requirements are recorded for Scenario A (no PHES, gas price low) across all three defined intervals. At current supported hydrogen capable blend rates, the range of maximum one day storage requirements were in the range 589 to 2,953 tonnes of hydrogen under the 'scaling' measure and between 1,046 to 3,319 tonnes of hydrogen under the 'whole gt' measurement method. Under 100% hydrogen fuel blend, the range (over both measurement methods) lies between 2,474 and 4,391 tonnes of hydrogen (both outcomes associated with the 9HA02 turbine).

These results extend to the two-day and seven-day interval designations as well. In the case of the two-day interval, the equivalent results are between 1,049 to 5,946 tonnes of hydrogen (at supported hydrogen blend rates and across both measurement method) and between

5,256 to 8,198 tonnes of hydrogen (at 100% hydrogen and across the two measurement methods).

For the seven-day interval, the equivalent results were between 2,320 to 14,291 tonnes of hydrogen (at supported hydrogen rates and across both measurement method) and between 11,625 to 20,943 tonnes of hydrogen (at 100% hydrogen and across both measurement methods).

The maximum short-term storage requirements for the other scenarios are lower than those of Scenario A and with lowest results being associated with Scenario E (both PHES operational with enhanced pumping). The lowest requirements for Scenario E are 343 to 2,875 tonnes (1-day); 566 to 4,585 tonnes (2-day); and 1,271 to 12,084 tonnes (7-day and across measurements methods).

It should be recognised that the results in Table 8 represent the *maximum* results compiled over the three above designated intervals. As such, the results present the maximum amount of renewable hydrogen that would be needed to satisfy the dispatch patterns over the relevant periods of time according to the two measurements methods being utilised. Such periods would be associated with quite intensive dispatch of the gas turbines. Moreover, over other equivalent time periods throughout the scenario year and the modelled scenarios, the modelled dispatch patterns produced hydrogen volume requirements that would be *less than* the maximum results cited in Table 8.

Table 8. Short term maximum storage requirements [tonnes of hydrogen (H2)]: by GE gas turbine and modelled scenario

Turbine/scenario		A	A	B	B		C	C	D	D	E	E
		one day maximum requirements										
		scaling	whole gt	scaling	whole gt		scaling	whole gt	scaling	whole gt	Scaling	whole gt
9HA02	50%	589	1,046	514	972		437	749	372	703	343	685
	100%	2,474	4,391	2,159	4,080		1,837	3,147	1,562	2,953	1,440	2,875
9F05	80%	1,661	2,308	1,450	1,994		1,233	1,625	1,049	1,462	967	1,366
	100%	2,970	4,127	2,592	3,565		2,205	2,906	1,875	2,613	1,728	2,442
9E04	100%	2,953	3,319	2,577	2,949		2,193	2,364	1,864	2,113	1,719	2,030
		consecutive maximum two-day requirements										
		scaling	whole gt	scaling	whole gt		scaling	whole gt	scaling	whole gt	Scaling	whole gt
9HA02	50%	1,049	1,952	899	1,740		798	1,323	600	1,194	566	1,092
	100%	4,403	8,198	3,776	7,305		3,349	5,556	2,519	5,012	2,375	4,585
9F05	80%	2,956	4,193	2,535	3,538		2,248	2,909	1,691	2,431	1,595	2,295
	100%	5,285	7,497	4,532	6,325		4,020	5,202	3,023	4,347	2,851	4,103
9E04	100%	5,256	5,946	4,507	5,253		3,997	4,250	3,006	3,498	2,835	3,331
		consecutive maximum seven-day requirements										
		scaling	whole gt	scaling	whole gt		scaling	whole gt	scaling	whole gt	Scaling	whole gt
9HA02	50%	2,320	4,987	2,110	4,673		1,693	2,924	1,341	3,026	1,271	2,878
	100%	9,740	20,943	8,861	19,622		7,110	12,278	5,631	12,706	5,338	12,084
9F05	80%	6,539	9,957	5,948	9,233		4,773	6,338	3,779	5,928	3,584	5,682
	100%	11,691	17,803	10,635	16,509		8,534	11,331	6,759	10,599	6,408	10,159
9E04	100%	11,625	14,291	10,575	13,121		8,486	9,157	6,721	8,226	6,372	7,880

4.5 Emission reductions associated with using the three GE hydrogen capable gas turbines

The Mt C02-e emission results associated with the four new OCGT plant and portfolio aggregate results by scenario was listed previously in Table 4. The aggregate portfolio results were compiled by aggregating across the four new OCGT plants. The equivalent aggregate portfolio results encompassing emission reduction calculations linked to the GE hydrogen capable turbines under consideration are reported in Table 9. Note that column 2 of Table 9 reproduces the last column of Table 4, corresponding to the case with no hydrogen (0%) fuel blending – that is, with 100% natural gas. Column 3 of Table 9 outlines the results applying the currently supported emission reduction rate of the 9HA02 turbine at 50% hydrogen blending. From the last column of Table 1, this configuration will produce a 23.8 percent reduction in emissions as outlined in column 3 of Table 9. In column 4 of Table 9, we apply the emission reduction rate currently supported by the 9F05 turbine of 55.9% assuming 80% hydrogen fuel blend as listed in Table 1. Column 5 of Table 9 contains the results associated with all GE hydrogen capable turbines at 100% hydrogen. In all cases, emissions are effectively eliminated at a 100% hydrogen fuel blend.

Overall, inspection of Table 9 clearly indicates that the magnitude of emission reductions increases with the degree of H2 fuel blend rate, with the rate of reduction also clearly showing the nonlinear relationship with H2 blending rate. For example, for Scenario A (e.g., no PHES and cheap gas supply offer), a 50% H2 fuel blend reduces emissions from 1.60 Mt C02-e to 1.23 Mt C02-e. In the case of 80% fuel blend, the emissions reduce from 1.60 Mt C02-e to 0.71 Mt C02-e. Finally, at 100% H2 fuel blend, emissions are reduced completely from 1.60 Mt C02-e to 0 Mt C02-e.

Table 9. Emissions of four new OCHGT plant by modelled scenario in Mt C02-e using Zero, 50% 80% and 100% hydrogen

Hydrogen (H2) blend	No hydrogen	50% hydrogen	80% hydrogen	100% hydrogen
Scenario		9HA02	9F05	all turbines
A “no Phes, GPlow”	1.60	1.23	0.71	0.00
B “Phes / GPlow, default pump”	1.08	0.82	0.48	0.00
C “no Phes, GPdefault,”	0.89	0.69	0.40	0.00
D ”Phes, GPdefault, default pump”	0.34	0.26	0.15	0.00
E	0.27	0.21	0.12	0.00

”Phes, GPdefault, enhanced pump”				

As Australia and Queensland move to a net zero environment, it will become more likely that emissions produced by the OCHGT plant will need to be offset by some certificate scheme that employs a carbon price on emissions. Earlier in this article, for the total emission listed in column 2 of Table 9, it was demonstrated that a $30/tC02-e carbon price would produce a carbon offset cost of between $8.1 million (Scenario E) and $48 million (Scenario A). Similarly, for a carbon price of $100/tC02-e, this would imply a higher cost of between 27 and 160 million dollars.

In the case of emission reduction associated with currently supported 50% hydrogen capability of the 9HA02 turbine, at $30/tC02, the nominal dollar range of carbon offset falls to between $6.4 million and $36.8 million, representing reductions in cost of between 1.7 and 11.2 million dollars relative to the emission outcomes in column 2 (the 0% hydrogen case). In the case of the 9F05 turbine with currently supported hydrogen capability of 80%, the nominal carbon offset cost falls between $3.7 and $21.3 million dollars, implying a reduction in offset cost relative to the 0% hydrogen case of between $4.4 and $26.7 million. In the case of 100% hydrogen, no emissions would arise and thus no carbon offsetting costs would be incurred relative to the 0% hydrogen case, representing a cost <u>reduction</u> in associated offset costs of between $8.1 and $48 million dollars.

The emission reduction associated with the supported 50% hydrogen capability of the 9HA02 turbine, at $100/tC02, the nominal dollar range of C02 offsets falls between $21.3 and $122.7 million, a reduction in carbon offset cost of between 5.7 and 37.3 million dollars relative to the 0% hydrogen case. In the case of the 9F05 supported hydrogen capability of 80%, the offset cost falls between $12.3 and $71 million dollars, implying a reduction in offset cost relative to the 0% hydrogen case of between $14.7 and $89 million. For the case of 100% hydrogen, no offsetting costs are incurred implying a reduction of between $27 and $160 million dollars in offset costs relative to the 0% hydrogen case listed in column 2 of Table 9.

5. Discussion and conclusions

The analysis of results indicates:

- Renewable hydrogen volumetric flow rates increase in a nonlinear fashion with hydrogen fuel blend percentage – a 100% hydrogen fuel blend will require much larger amounts of renewable hydrogen than would be required by even a modest reduction in hydrogen fuel blend rate;
- Gas turbines utilising hydrogen as a fuel will require some modification to accommodate the different properties it possesses compared with methane (CH_4). Such modifications are available; and

- Decarbonisation of gas-fired power generation utilising hydrogen capable gas turbines would require the use of very high hydrogen fuel blends in these gas turbines.

Short-term storage observations potentially permitted some degree of flexibility in how the short-term storage requirements are managed onsite. This would encompass consideration on whether to base the short-term storage requirements on 1 or 2-day consecutive intervals within a weekly 'top- up' of storage volume strategy to meet the evolution of dispatch requirements over the week. Second, an alternative approach might be to have an emergency reserve available that is stored onsite in dedicated storage tanks and depend on linepack manipulation to manage day-to-day hydrogen flow requirements.

However, in positing such storage strategies, account would also need to be taken of potential modifications to existing storage infrastructure (whether pipes, compressors, storage tanks as well as material composition that affects integrity) to accommodate the different properties of hydrogen relative to methane or diesel. Furthermore, the requirement for high quality freshwater to supply electrolysers will, in part, dictate the need for short-term storage. This is additional to the land needed for electrolysers and whether this land is available at the gas turbine site or 'over the fence'. Moreover, with the separation of hydrogen production activities and electricity supply from hydrogen capable gas turbines, electrolysers could be dispatched as required for generation of hydrogen when the gas turbine is dispatched to supply the grid.

These results indicate significant reductions are possible in carbon offset costs associated with the use of hydrogen capable gas turbines in place of standard gas turbines running on 100% natural gas. These cost reductions relative to the 0% hydrogen case (i.e.,100% natural gas) increase significantly with increases in hydrogen fuel blend rates, given the non-linearity of emissions reduction with increasing hydrogen blends. At the margin, offset costs disappear completely for the 100% hydrogen fuel blend case. It should also be noted that these cost savings represent saving calculated over one year only and would continue to accrue over the years of the turbines operating life in an environment containing policy goals requiring carbon emissions to be offset.

The carbon offset costs cited above also indicate the importance of the carbon price used in these calculations. In the article, the highest value used was \$100/tC02-e (AUD). However, recently the United States Environmental Agency (EPA) proposed raising the USA (USD) social cost of carbon from \$51/tC02-e to \$190/tC02 (Asdourian and Wessel, 2023). Applying an exchange rate value for USD to AUD conversion of 0.7, the AUD equivalent would be \$271.43/tC02-e (AUD). Thus, the possibility of significant increases in social cost of carbon in the future could not be ruled out. To the extent that such increases might arise, then this would increase carbon offset costs very substantially. This, in turn, is likely to further incentivise attempts to fully decarbonise operations of gas turbines operating in a network balancing role.

The hydrogen fuelled gas turbines considered in this article have currently supported hydrogen fuel blend capabilities of between 50% to 100%. This article illustrates, through a range of simulations, that OCGT using hydrogen blends offer a solution to the challenge facing the electricity grid as it decarbonises. The challenge examined in this article is ability to supply the peak demand periods – one-, two- and seven-day periods - where all other energy sources have been dispatched. However, this hydrogen solution comes with its own challenges: the quantity and flow rate of hydrogen to meet this peak demand, the nonlinear reduction in emissions with hydrogen blend percentage and the risk of penalty with a carbon price regime.

The focus of this article has been to investigate how much renewable hydrogen (on both an annualised tonnage basis as well as over shorter-term storage durations) would be needed to underpin the dispatch of four new OCGT plant that was included in the modelling. These generation sources were principally seen as providing network balancing services, often within the context of a last resort generation source that is available when all others pre-existing resources have been exhausted, but additional energy is still needed to balance the network.

Whilst our findings relating to technical assessment of hydrogen capable gas turbines and the renewable hydrogen requirements are a promising start, further analysis of the economic viability of these types of gas turbines is needed to improve understanding of the role that they might contribute in decarbonising gas-fired generation over the medium to long-term, thereby allowing it to continue to play a role within the NEM as the latter transitions to a 2050 net zero operating environment.

Another area requiring further investigation is engineering based assessment of technical requirements associated with H2 production, transportation and storage, within the context of hydrogen capable gas turbines, taking account of likely annual and short-term storage requirements to fulfil a network balancing role.

The conclusion from this research is that the use of hydrogen at scale can assist the electricity generation system to decarbonise. This offers hope to the hard-to-abate industries given their requirements for hydrogen at scale in their journey. This will be explored in a later article.

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Appendix A: Individual OCHGT plant results

9HA02											
Scenario	H2	CWQ		Gladstone		Tarong		Moreton South		Total	
	%	scaling	whole gt	scaling	whole gt	scaling	whole gt	scaling	whole gt	scaling	whole gt
A	50%	6,762	22,494	7,166	23,077	6,542	21,985	13,717	29,295	34,187	96,851
	100%	28,394	94,456	30,093	96,904	27,471	92,319	57,601	123,014	143,558	406,693
B	50%	4,300	16,896	4,561	17,516	4,714	17,414	9,719	23,290	23,295	75,116
	100%	18,058	70,949	19,153	73,552	19,795	73,125	40,812	97,798	97,819	315,423
C	50%	11,732	20,986	164	370	3,150	6,551	818	1,832	15,864	29,739
	100%	49,263	88,123	689	1,554	13,227	27,509	3,436	7,693	66,615	124,879
D	50%	992	3,359	1,241	4,525	1,021	3,081	4,797	10,669	8,050	21,634
	100%	4,164	14,104	5,211	19,000	4,287	12,939	20,144	44,800	33,805	90,843
E	50%	803	2,683	996	3,451	832	2,619	3,731	8,170	6,362	16,924
	100%	3,372	11,268	4,183	14,493	3,492	10,996	15,667	34,309	26,715	71,065
9F05											
Scenario	H2	CWQ		Gladstone		Tarong		Moreton South		Total	
	%	scaling	whole gt	scaling	whole gt	scaling	whole gt	scaling	whole gt	scaling	whole gt
A	50%	19,062	38,846	20,202	40,239	18,442	37,904	38,670	59,881	96,376	176,870
	100%	34,080	69,453	36,120	71,944	32,973	67,768	69,138	107,062	172,311	316,228
B	50%	12,123	27,810	12,858	28,971	13,289	29,258	27,399	46,277	65,669	132,315
	100%	21,675	49,721	22,989	51,797	23,760	52,310	48,986	82,738	117,411	236,566
C	50%	33,072	45,225	462	724	8,880	13,208	2,307	3,620	44,721	62,777
	100%	59,129	80,858	826	1,294	15,877	23,615	4,124	6,472	79,957	112,239
D	50%	2,795	6,010	3,498	7,922	2,878	5,518	13,523	21,089	22,695	40,540
	100%	4,998	10,745	6,254	14,164	5,145	9,866	24,178	37,706	40,576	72,482
E	50%	2,264	4,781	2,808	6,051	2,345	4,712	10,518	16,350	17,934	31,894
	100%	4,048	8,547	5,021	10,819	4,192	8,425	18,805	29,232	32,065	57,023

9E04											
Scenario	H2	CWQ		Gladstone		Tarong		Moreton South		Total	
	%	scaling	whole gt	scaling	whole gt	scaling	whole gt	scaling	whole gt	scaling	whole gt
A	100%	33,889	49,607	35,917	51,827	32,788	48,162	68,750	84,421	171,345	234,016
B	100%	21,553	33,847	22,861	35,638	23,627	36,211	48,712	62,728	116,752	168,423
C	100%	58,798	64,984	822	979	15,788	18,553	4,101	5,086	79,509	89,602
D	100%	4,970	7,653	6,219	9,647	5,116	7,199	24,043	29,286	40,348	53,785
E	100%	4,025	6,137	4,993	7,474	4,168	5,922	18,699	22,672	31,885	42,204

Appendix B: individual plant storage requirements

1-day	H2	CWQ		Gladstone		Tarong		Moreton South		Total	
GE turbine	%	scaling	whole gt	scaling	whole gt	scaling	whole gt	scaling	whole gt	scaling	whole gt
9HA02	50%	51	130	65	176	57	102	169	278	343	685
	100%	214	544	274	738	240	427	712	1,166	1,440	2,875
9F05	80%	144	232	184	314	161	219	478	601	967	1,366
	100%	257	415	329	562	288	391	854	1,075	1,728	2,442
9E04	100%	256	346	327	442	286	322	849	919	1,719	2,030
2-day	H2	CWQ		Gladstone		Tarong		Moreton South		Total	
	%	scaling	whole gt	scaling	whole gt	scaling	whole gt	scaling	whole gt	scaling	whole gt
9HA02	50%	94	222	117	278	64	139	291	453	566	1,092
	100%	396	933	490	1,166	267	583	1,223	1,904	2,375	4,585
9F05	80%	266	437	329	519	179	273	821	1,065	1,595	2,295
	100%	475	781	588	928	320	488	1,468	1,905	2,851	4,103
9E04	100%	472	633	585	740	319	382	1,459	1,576	2,835	3,331
7-day	H2	CWQ		Gladstone		Tarong		Moreton South		Total	
	%	scaling	whole gt	scaling	whole gt	scaling	whole gt	scaling	whole gt	scaling	whole gt
9HA02	50%	173	555	231	749	101	278	766	1,295	1,271	2,878
	100%	727	2,331	972	3,147	424	1,166	3,216	5,440	5,338	12,084
9F05	80%	488	983	652	1,298	285	505	2,159	2,896	3,584	5,682
	100%	873	1,758	1,167	2,320	509	904	3,860	5,177	6,408	10,159
9E04	100%	868	1,301	1,160	1,683	506	597	3,838	4,298	6,372	7,880