Environmental Defenders Office

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Complaint about potential greenwashing by APPEA

1. We act for Lock the Gate and Comms Declare. Lock the Gate is a national grassroots organisation made up of over 120,000 supporters and 260 local groups who are concerned about the ongoing and rapid expansion of risky coal mining, coal seam gas and fracking. Comms Declare is a climate advocacy group consisting of more than 360 marketing, PR, advertising and media organisations who have committed not to support activities or organisations that promote the growth of fossil fuels, high greenhouse gas pollution or deception around climate science.

2. Our clients request that the Australian Competition and Consumer Commission (**ACCC**) investigate whether representations made by the Australian Petroleum Production and Exploration Association (**APPEA**), the peak body representing 200 members of the oil and gas industry which collectively produce around 95% of Australia's oil and gas,[1] in relation to its "future of gas" campaign are in breach of ss 18 and 29 of the Australian Consumer Law (**ACL**) (Schedule 2 of the *Competition and Consumer Act* 2010 (Cth)).

3. The "future of gas" campaign promotes fossil gas as essential to the transition to a net zero economy without providing information about the role of renewable energy in the transition. As such, our client considers that the campaign attempts to allay community concerns relating to the environmental harms caused by emissions associated with the production and end-use of fossil gas and promotes current and future gas consumption in Australia.[2]

4. Our clients note the ACCC's Compliance and Enforcement Priorities for 2022-2023, which include 'consumer and fair-trading issues in relation to environmental claims and sustainability'[3] and the impetus placed on this priority by Delia Rickard, the ACCC Deputy Chair, at the Sydney

[1] APPEA 'Who we are' (accessed 30 June 2023).
[2] *ACCC v Homeopathy Plus! Australia Pty Limited* [2014] FCA 1412.
[3] ACCC 'Enforcement and Compliance Policy and Priorities' (accessed 29 June 2023).

Morning Herald Sustainability Summit on 20 September 2022.[4] Our clients consider that the campaign is potentially a 'false and misleading sustainability claim [that] undermine[s] consumer trust in all green claims and reduce[s] confidence in the market' and, as such, we refer it to the ACCC for investigation.[5]

Statements

5. The "future of gas" campaign consists of a series of statements relating to the environmental benefits of gas and its future role made on various media including its Website,[6] on YouTube,[7] and in an Opinion Piece[8] published in four newspapers across Australia (together, the **Statements**).

6. A list of the Statements is contained in **Annexure A**.

7. Screengrabs of the YouTube film is contained in **Annexure B**.

Representations

8. Our clients consider that the Statements, alone or in combination, represent that:

   (i) The overall emissions intensity of gas is 50% that of coal.

   (ii) Gas is replacing coal's share of electricity generation in Australia.

   (iii) Gas generates 20% of electricity used in Australia.

   (iv) Gas represented 27% of Australia's household energy consumption in 2020-2021.

   (v) APPEA is taking action consistent with achieving net zero emissions by 2050.

   (vi) The production of blue hydrogen releases low levels of carbon dioxide into the atmosphere.

(together, the **Representations**).

9. Our clients consider that the Representations are indicative of a sustained campaign by APPEA to market fossil gas as a "clean" energy source that is essential for the reduction of global greenhouse gas emissions to net zero by 2050 and to sustain the "Australian way of life".

10. A table summarising the representations by APPEA and why they are potentially misleading or deceptive is below:

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[4] ACCC 'Speech to Sydney Morning Herald Sustainability Summit' (accessed 29 June 2023).
[5] ACCC 'Speech to Sydney Morning Herald Sustainability Summit' (accessed 29 June 2023).
[6] https://futureofgas.com.au/.
[7] https://www.youtube.com/@APPEALimited/videos.
[8] Opinion Article: APPEA Chief Executive Samantha McCulloch on the importance of gas to Australia and net zero (Herald Sun, Adelaide Advertiser, West Australian) | APPEA.

Representation	Why the representations are potentially misleading
The overall emissions intensity of gas is 50% that of coal.	The whole life cycle of gas releases significant methane into the atmosphere, eliminating any benefit of switching from gas to coal. Renewable energy releases almost zero emissions.
Gas is replacing coal's share of electricity generation in Australia.	Gas usage for electricity generation decreased 40% from 2012-2022 and is forecast to decrease a further 34% to 2030 in the NEM. Renewable energy generation is replacing coal's share in Australia.
Gas generates 20% of electricity used in Australia.	In the last financial year, gas generated 5.6% of electricity used in the NEM.
Gas represented 27% of Australia's household energy consumption in 2020-2021.	Gas represented less than 11% of Australia's household energy consumption in 2021.
APPEA is taking action consistent with achieving net zero emissions by 2050.	APPEA is supporting the development of new gas projects by its members in Australia, a policy which is inconsistent with net zero by 2050.
The production of blue hydrogen releases low levels of carbon dioxide into the atmosphere.	The production of blue hydrogen releases significant levels of carbon dioxide into the atmosphere.

The overall emissions intensity of gas is 50% that of coal (Representation 1)

11. Our clients consider that Representation 1 is potentially misleading or deceptive for the reasons set out below.

Intensity is 61% of that of coal

12. According to a report by Climate Analytics titled "Factchecking the APPEA", (**Climate Analytics Report**)[9] data from the National Energy Market (**NEM**) demonstrates that average greenhouse gas (**GHG**) emissions per unit of gas generation is 61% of that of coal, substantially higher than the 50% claimed by APPEA. This is because the emissions intensity of gas depends on the precise CO2 content of the gas reservoir and the type of plant where the gas is combusted.

[9] Bill Hare, Climate Analytics, Briefing: Factchecking the APPEA (8 June 2023) p2-3.

13. Further information in relation to the emissions intensity of gas compared to coal is provided in the Climate Analytics Report which is contained in **Annexure C**.

Whole of life cycle emissions

14. Further, our clients consider that Representation 1 does not disclose the significant GHG emissions associated with the whole of life cycle of fossil gas. For gas and any other fossil fuel, life cycle analysis is used to quantify the total amounts of GHG emissions from every step in the process: from extraction at the well, to processing and domestic pipeline transportation, to liquification (converting it to LNG), to tanker transport, regasification and burning it at a power plant to generate electricity, or any other facility (the "end-use"). During these processes, GHGs – mostly CO2 and methane – are deliberately released into the atmosphere by venting or flaring, from the unprocessed gas stream. There is also inadvertent release of GHGs into the atmosphere throughout this process. The intentional and inadvertent release of pre-combustion GHGs into the atmosphere by the gas industry is known as "fugitive emissions".

15. Fossil gas mostly consists of methane, significant quantities of which are released into the atmosphere at every point along the gas supply chain. Methane is a more potent GHG than CO2 in terms of its contribution to global warming. Over a 20-year period, methane is 84 times more effective than CO2 in trapping heat, and 28 times more effective over 100 years.[10] Actual rates of methane leakage from the development of gas resources, from exploration through to combustion, have consistently exceeded pre-development estimates.[11] Methane that cannot be used for production is also routinely flared (combusted) at drilling sites, which causes further GHGs to be released into the atmosphere. In a report titled 'Passing Gas: Why Renewables are the Future', the Climate Council reported that the proportion of pre-combustion GHGs per unit of energy released along the gas supply chain in Australia is significantly more than that of coal.[12]

16. In addition to GHG emissions associated with extraction and production, the combustion of fossil gas to produce energy (electricity generation) releases significant quantities of GHGs into the atmosphere. Whilst it may be the case that, generally speaking, combusting coal for electricity (the "end-use") is more emissions intensive than combusting gas, when fugitive gas that has leaked during the extraction, processing and transport of gas is taken into account, any reduction in emissions as a result of shifting from coal generation to gas is significantly reduced.[13] As such, gas is only less emissions intensive than coal if a large proportion of its overall emissions are ignored.

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[10] Penny D Sackett *Expert Report on the Greenhouse Gas and Climate Implications of the Narrabri Gas Project 40 (SSD6456)* (9 August 2020) p7, available at sackett-narrabri-gas-project-ipc-advice-revised_final.pdf (nsw.gov.au); CSIRO, *Mitigation and Offsets of Australian Life Cycle Greenhouse Gas Emissions of Onshore Shale Gas in the Northern Territory* (2022) pages 33-34, available at: GISERA report template (csiro.au).

[11] Benjamin Hmiel et al, '*Preindustrial 14CH4 indicates greater anthropogenic fossil CH4 emissions*', Nature 578, 19 41 February 2020, pages 409- 412 available at: Preindustrial 14CH4 indicates greater anthropogenic fossil CH4 emissions (blm.gov).

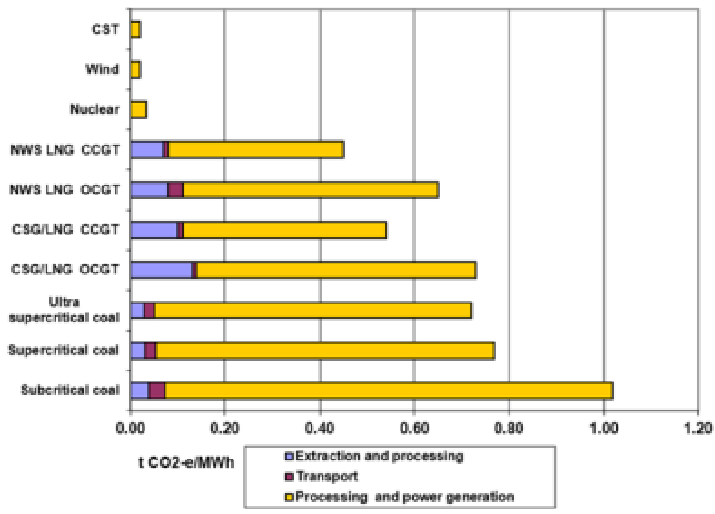
[12] Climate Council, *Passing Gas: Why Renewables are the Future* (2020), p22 available at: FINAL-CC_MVSA0245-CC-Report-Gas_V5-FA_Low_Res_Single_Pages.pdf (climatecouncil.org.au).

[13] Mazengarb, M. "Gaslighting Australia: How gas industry is driving up emissions" (2 June 2020), available at: Gaslighting Australia: How gas industry is driving up emissions | RenewEconomy.

17. In 2020, the Natural Resources Defence Council in the US published a report analysing the GHG emissions generated across the life cycle of Liquified Natural Gas (**LNG**).[14] The report found that high rates of methane leakage reduces the climate benefit of LNG because half of the total life cycle emissions occur *before* the gas is combusted for electricity generation, mostly from methane leaks during the extraction, processing, domestic pipeline transportation, liquification and regasification processes required for overseas export of LNG.[15] This is significant because, in 2018-2019, about 80% of gas produced in Australia was liquified for export.[16]

18. A comparison of the life cycle emissions intensity of Australian LNG as compared to other energy sources is illustrated in the table below. This shows that extracting and processing LNG (i.e., pre-combustion processing) releases more GHGs into the atmosphere than coal, and that emissions associated with processing and electricity generation is *highly* dependent on the type of gas or coal used and the type of power station used for combustion. For example, the extraction and processing of CSG/LNG (Coal Seam Gas/Liquified Natural Gas) releases significantly more GHGs than ultra supercritical coal. Therefore, the claim that gas can produce electricity at 50% of the emissions intensity of coal, and that gas supports the deployment of renewables in the transition, can only be true when certain kinds of coal and coal plants are compared to certain kinds of gas and gas plants.[17]

Figure 7. Life cycle GHG emissions intensities for Australian fossil fuel exports, and selected renewables and nuclear, base case.



19. We note the recent decision of Ads Standards (28 June 2023) in relation to a television advertisement run by APPEA as part of its "future of gas" campaign that the claim that "gas is

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[14] NRDC, 'Sailing to Nowhere: Liquefied Natural Gas is not an Effective Climate Strategy', December 2020, available at: NRDC: Sailing to Nowhere - Liquefied Natural Gas Is Not an Effective Climate Strategy (PDF).
[15] Ibid, p14.
[16] The Australia Institute, 'On the make: gas an manufacturing in Australia' (November 2020) p6 available at: On the make (australiainstitute.org.au).
[17] Climate Council, *Passing Gas: Why Renewables are the Future* (2020), p27 available at: FINAL-CC_MVSA0245-CC-Report-Gas_V5-FA_Low_Res_Single_Pages.pdf (climatecouncil.org.au).

50% cleaner than coal" was misleading or deceptive, including because it did not include "…any qualifications stating what kinds of gas vs coal plants this applies to."[18]

20. We further note that the ACCC in its guideline *Green marketing and the Australian Consumer Law* recommended: "When making claims about a particular characteristic or part of a product, you should also consider the whole product life cycle." Accordingly, our client considers that claims relating to the emissions intensity of gas compared to coal must include the full life cycle GHG emissions, including pre-combustion methane emissions, as these often account for the majority of emissions. As such, our clients consider that, by "cherry picking" the emissions associated with one particular part of the life cycle fossil gas compared to those of coal (i.e., end-use), Representation 1 is potentially misleading. This is because it fails to disclose that, if the full climate impact of gas is considered, including methane emissions (a GHG which has a far greater and more immediate climate impact), the climate benefit of gas compared to coal is significantly reduced.

<u>Comparison with renewables</u>

21. By comparison, the emissions intensity of gas electricity generation is *significantly* higher than the very low emissions associated with electricity produced by solar and wind (as indicated in the table above).

22. Our clients consider that comparing emissions associated with gas only to those associated with coal without also comparing gas to the emissions associated with renewable energy generation is potentially misleading. Failing to disclose this information may lead the reader to the false conclusion that gas is the only energy source that releases less GHGs than coal when in fact, renewable energy sources release almost zero GHGs in the production of energy.

23. In that regard, we note the decision of the Australian Advertising Standards Authority that an Australian Gas Networks advertisement with the use of the terms "clean" and "cleaner" in relation to gas was misleading when there are other energy sources that would be considered "greener" and "cleaner" than gas.[19]

24. Accordingly, our clients further consider that Representation 1 is misleading because it overstates the benefits of natural gas compared to coal but fails to disclose the environmental harm caused by gas, and that the emissions intensity of renewable energy is significantly lower than those of gas.

Gas is replacing coal's share of electricity generation in Australia (Representation 2)

25. Our clients consider that, taken together, the relevant statements convey the representation that gas is replacing coal's share of electricity generation in Australia. Our clients consider that Representation 2 is potentially misleading or deceptive for the reasons set out below.

[18] Ads Standards, Case Report 0119-23, APPEA Ltd (28 June 2023) available at: 0119-23.pdf (adstandards.com.au).

[19] Ads Standards, Case Report 0202-20, Australian Gas Networks (8 July 2020) available at: 0202-20.pdf (adstandards.com.au).

26. Coal is in structural decline in Australia. The latest Integrated System Plan by the Australian Energy Market Operator (**AEMO**), which sets out the future of the NEM (Australia's largest grid), forecasts that between 40% and 95% of coal-fired generation capacity will retire over the next 20 years with no new coal-fired generator to replace it.[20] By comparison, renewable energy's share of total annual generation is forecast to rise from approximately 32% in 2021-2022 to 83% in 2030-2031, to 96% by 2040 and to 98% by 2050. In the most likely scenario, the AEMO forecasts that there will be enough potential renewable resources to meet 100% of grid demand for a small number of dispatch periods from as early as 2025.[21] As such, AEMO predicts that a significant portion of coal-fired capacity will retire in the next 20 years as wind and solar generation capacity more than triples.

27. IN relation to gas' role in the transition, a report by the Institute for Energy Economics and Financial Analysis titled 'Gas' role in the transition: a fuel transitioning out of the energy system' (**IEEFA Report**)[22] found that gas usage for electricity generation *decreased* 40% from 2012-2022 and is forecast to decrease a further 34% to 2030.[23] By comparison, renewable electricity generation *increased* its share in the NEM from 14% in 2014 to 35% in 2022.[24] In the previous financial year, data from the AEMO shows that gas supplied only 5.6% of electricity demand in the NEM from 30 May 2022 to 11 June 2023 (less than coal, wind, solar and hydro).[25]

    A copy of the report by IEEFA is contained in **Annexure D**.

28. A recent report commissioned by the Grattan Institute titled 'Getting off gas: why, how and who should pay' (2023) states that characterising gas as a "transition fuel" is redundant because coal-fired electricity generators are not being replaced by gas when they are retired but by renewable energy and storage. In relation to industry, it states that there is no time to switch from coal to gas and then gas to renewable hydrogen and that companies are instead waiting for zero-emissions alternatives to become cheaper, so as to cut out gas as a transition fuel.[26]

29. Accordingly, our clients consider that Representation 2 is potentially misleading because it fails to disclose that, as coal fired generation is decreasing, so gas fired generation is *also* decreasing and that renewable generation is increasing. The more accurate statement, therefore, is that renewable energy is replacing coal's share of electricity generation in Australia.

Gas generates 20% of electricity used in Australia (Representation 3)

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[20] AEMO, 2022 Integrated System Plan (June 2022), p 49 available at: 2022-integrated-system-plan-isp.pdf (aemo.com.au).
[21] Ibid, p45.
[22] Bruce Robertson, Institute for Energy Economics and Financial Analysis, 'Gas' role in the transition: a fuel transitioning out of the energy system' (May 2023) (**IEEFA Report**), p2, available at: Gas Role in the Transition May 2023_0 (2).pdf.
[23] IEEFA Report, p3.
[24] IEEFA Report, p4.
[25] AEMO, OpenNEM: NEM (accessed 4 July 2023).
[26] A. Reeve, E. Sucking and T Wood "Getting off gas: Why, how and who should pay?" 2023), p6 available at: Getting off gas: why, how, and who should pay? (grattan.edu.au).

30. Our clients consider that Representation 3 is potentially misleading for the reason stated in [25] above, namely, that in the previous financial year, data from the AEMO shows that gas generated only 5.6% of the electricity demand in the NEM from 30 May 2022 to 11 June 2023.[27] Furthermore, the source cited to substantiate the relevant statement on the "future of gas" website is the Australian Energy Update 2022,[28] which states that gas had an 18% share in 2020-21, a figure that is now outdated.

31. As such, our clients consider that Representation 3 is potentially misleading because gas generated only 5.6% of electricity in the NEM for the previous financial year.

Gas represented 27% of Australia's household energy consumption in 2020-2021 (Representation 4)

32. Our clients consider that the relevant statement conveys Representation 1, in particular that it refers to the consumption of gas by *households*. This is implied by the list of household uses of gas immediately preceding the statement that gas represents 27% of Australia's domestic consumption. Further, one of the meanings of "domestic" according to the Cambridge Dictionary is "belonging or relating to the home, house or family".[29] Our client further considers that Representation 4 is potentially misleading or deceptive for the reasons set out below.

33. The proportion of gas consumed by households in Australia in 2021 was less than 11% (this figure is likely inflated because it includes services and agriculture as well as residential consumption).[30] Regardless, 11% is significantly lower than 27% and, as such, our client considers that Representation 4 is potentially misleading.

34. In the event that the word "domestic" is taken to mean "within Australia", our client considers that Representation 4 is still misleading because it fails to disclose that in the 2018-2019 financial year, nearly 80% of gas produced in Australia was used for the production and manufacturing of LNG for *export*.[31] According to the report by Climate Analytics, in 2020-2021 this figure rose to 83%.[32] Our client considers that Representation 4 exaggerates the role of gas in the Australian economy because 83% of gas consumed in Australia is consumed by the gas industry to convert the gas that it produces into LNG which is exported and consumed internationally.

35. Further, when gas consumed by LNG exports is factored out of the 27% figure, according to the Climate Analytics Report, the proportion of gas consumed domestically has, in fact, declined to 21%.[33] While domestic consumption of gas declined from 2014-2021, the consumption of gas for LNG export has increased.[34]

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[27] AEMO, OpenNEM: NEM (accessed 4 July 2023).
[28] Australian Energy Update 2022, p26.
[29] Cambridge Dictionary online available at: DOMESTIC | English meaning - Cambridge Dictionary.
[30] See Australia Energy Information | Enerdata.
[31] Ibid, p10.
[32] Bill Hare, Climate Analytics, Briefing: Factchecking the APPEA (8 June 2023) p3.
[33] Bill Hare, Climate Analytics, Briefing: Factchecking the APPEA (8 June 2023) p6.
[34] Bill Hare, Climate Analytics, Briefing: Factchecking the APPEA (8 June 2023) p6.

36. As such, our client considers that Representation 4 is potentially misleading because less than 11% of gas is consumed by households. Further, and alternatively, 83% of gas produced is consumed by the LNG industry for export, and when LNG consumption is factored in, gas represents only 21% of domestic energy consumption.

APPEA is taking action consistent with achieving net zero emissions by 2050 (Representation 5)

37. Our clients consider that the relevant statement conveys the representation that APPEA is taking action that is consistent with achieving net zero emissions by 2050 or, at least, is not taking action that is *inconsistent* with the same.

38. Reducing GHG emissions to net zero by 2050 is required to reach the goal of the Paris Agreement, which is to limit global warming to 1.5 degrees or well below 2 degrees. Under the International Energy Agency's (**IEA**) Net Zero Emissions by 2050 scenario (**NZE**), between 2021 and 2050, fossil gas demand declines by more than 70%. That means that, to keep global temperatures below 1.5 degrees, 70% of gas reserves must remain untapped.[35] Furthermore, the IEA stated that the rapid drop in oil and gas demand in the NZE means that no new fossil fuel exploration is required, and no new oil and gas fields are required beyond those that have already been approved for development.[36]

39. APPEA is the peak industry body for the oil and gas industry. The sole purpose of its "future of gas" campaign is to ensure public support for the continued exploration, production, processing and combustion of fossil gas into the future. Indeed, APPEA's current "policy priorities" include promoting *new* gas supply and supporting *new* oil and gas development by lobbying states to lift moratoriums on *new* exploration and development.[37] As such, our clients consider that prioritising the development of new gas reserves is *entirely* inconsistent with achieving net zero emissions by 2050 in circumstances where the IEA has stated that there must be no new oil and gas development if the world is to reach net zero emissions by 2050. Accordingly, our clients consider that Representation 5 is potentially misleading.

The production of blue hydrogen releases low levels of carbon dioxide into the atmosphere (Representation 6)

40. Our clients consider that the relevant statement at Annexure A conveys Representation 6. Taken contextually, our clients consider that "low carbon" hydrogen refers to "blue" hydrogen, which is hydrogen produced from fossil gas with carbon capture and storage (**CCS**). That is because "green" hydrogen — hydrogen produced from renewable energy — produces *zero* CO2 whereas proponents of blue hydrogen claim that its production releases *low* levels of CO2. This, together with the reference to CCS in the same sentence, implies that "low carbon" hydrogen is blue hydrogen.

[35] IEA, World Energy Outlook 2022, p133 available at: World Energy Outlook 2022 (windows.net).
[36] IEA, Net Zero by 2050: A Roadmap for the Global Energy Sector (October 2021), p51 available at: Net Zero by 2050 - A Roadmap for the Global Energy Sector (windows.net).
[37] APPEA website: Policy - Energy security | APPEA.

41. Our client considers that Representation 6 is potentially misleading because the production of blue hydrogen releases significant CO2 into the atmosphere. In that regard, in a paper titled "Clean hydrogen? – Comparing the emissions and costs of fossil fuel versus renewable electricity based hydrogen" academics at the ANU said that hydrogen produced using fossil fuels causes GHG emissions even when CCS is used, and that the amount of CO2 captured depends on a variety of factors, including how and where in the process it is captured but also what is done with it after it is captured.[38] If it is used for Enhanced Oil Recovery, it can result in CO2 being re-emitted into the atmosphere.[39] Whilst there are different techniques that can be used to capture the CO2, they all require additional energy and themselves result in additional emissions.[40] Furthermore, the extraction and processing of fossil gas as a feedstock itself directly releases CO2 into the atmosphere due to venting and flaring.[41] Representation 6 is also silent as to the methane emissions associated with the production of blue hydrogen, which is a potent greenhouse gas (as discussed above).

    A copy of the blue hydrogen paper is contained in **Annexure E.**

Potential legal contraventions

42. Section 18 of the ACL provides that:

    > *A person must not, in trade or commerce, engage in conduct that is misleading or deceptive or is likely to mislead or deceive.*

43. The Statements are also likely to raise concerns about potential breaches of s 29 of the ACL. Section 29 relevantly states:

    1) A person must not, in trade or commerce, in connection with the supply or possible supply of goods or services or in connection with the promotion by any means of the supply or use of goods or services:

        b) make a false or misleading representation that services are of a particular standard, quality, value or grade; …

        g) make a false or misleading representation that goods or services have sponsorship, approval, performance characteristics, accessories, uses or benefits; or

        h) make a false or misleading representation that the person making the representation has a sponsorship, approval or affiliation.

44. When determining whether conduct is misleading or deceptive the central question is whether the impugned conduct, viewed as a whole, has a sufficient tendency to lead a person exposed

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[38] Longden T. et al, p2 available at: ['Clean' hydrogen? – Comparing the emissions and costs of fossil fuel versus renewable electricity based hydrogen (mcusercontent.com)].

[39] Longden T. et al, p2.

[40] Longden T. et al, p4.

[41] Longden T. et al, p2 ['Clean' hydrogen? – Comparing the emissions and costs of fossil fuel versus renewable electricity based hydrogen (mcusercontent.com)].

to the conduct into error.[42] In making this assessment it is unnecessary to prove that the conduct in question actually deceived or misled anyone.[43] Additionally, if the conduct in question is directed to the public (or a section of the public), the Court will consider the likely effect on an ordinary and reasonable person in the relevant class to whom the conduct is directed.[44]

45. Our client considers that the breadth of person to whom the representations were directed was broad. The "future of gas" campaign containing the Representations was published across various media, including the "future of gas" Website, on YouTube and by publication of the Opinion Piece in four newspapers across Australia. Our client considers that the potential class of consumers viewing the Website, YouTube film and Opinion Piece should be presumed to include "…the astute and the gullible, the intelligent and the not so intelligent, the well-educated as well as the poorly educated, and men and women of various ages pursuing a variety of vocations."[45] In determining whether the "future of gas" campaign was misleading or deceptive, it is necessary to assess at the time of publication, the likely effect of the Representations on members of this broad class acting reasonably in all of the circumstances.

Is APPEA a "person"?

46. APPEA is an Australian public company limited by guarantee,[46] and, as such, is "person" for the purpose of the ACL.

Was the conduct in "trade and commerce"?

47. The legal test as to whether conduct is in trade and commerce is as follows:

> *…the conduct of a corporation towards persons, be they consumers or not, with whom it … has or may have dealings in the course of those activities or transactions which, of their nature, bear a trading or commercial character. Such conduct includes, of course, promotional activities in relation to, or for the purposes of, the supply of goods or services to actual or potential customers be they identified persons or merely an unidentifiable section of the public …*[47]

48. In *Tobacco Institute of Australia Ltd v Australian Federation of Consumer Organisations Inc* (1992) 111 ALR 61, the issue on appeal was whether the publishing of an advertisement by the Tobacco Institute essentially claiming that passive smoking does not cause disease was in trade or commerce. In finding that the conduct was in trade or commerce, Foster J said at [83] that:[48]

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[42] *Australian Competition and Consumer Commission v TPG Internet Pty Ltd* (2020) 278 FCR 450, 458 (the Court).
[43] *Taco Co of Australia Inc v Taco Bell Pty Ltd* (1982) 42 ALR 177, 202 (Deane and Fitzgerald JJ).
[44] *Campomar Sociedad, Limitada v Nike International Ltd* (2000) 202 CLR 45, 85 (the Court).
[45] *ACCC v Homeopathy Plus! Australia Pty Limited* [2014] FCA 1412 [128] (Perry J).
[46] APPEA Limited, ABN 44 000 292 713: View Details - Organisations and Business Names (asic.gov.au).
[47] *Concrete Constructions (NSW) Pty Ltd v Nelson* (1990) 169 CLR 594 (***Concrete Constructions***), 602 (Mason CJ, Deane, Dawson and Gaudron JJ).
[48] *Tobacco Institute of Australia Ltd v Australian Federation of Consumer Organisations Inc* (1992) 111 ALR 61; Perry J provides a comprehensive summary of the law in *ACCC v Homeopathy Plus! Australia Pty Limited* [2014] FCA 1412 at [289]-[298].

> *The material was... published extensively nation-wide. The advertisement was prominent and eye-catching and described itself as an advertisement. Even the most cursory reading of it would, in my view, have been sufficient to convey to an ordinary reader a message favourable to the consumption of cigarettes as an article of commerce. The advertisement was persuasive in tone. It sought to allay fears which it suggested were commonly and erroneously held that the inhalation of tobacco smoke in the air could be harmful. The name of the appellant, appearing as the authoriser of the advertisement, would, in my view, when coupled with its obvious message, be quite capable of conveying to such a reader that the appellant had a commercial interest in assuaging community concerns about the harmful effects of inhaling environmental tobacco smoke. The general tenor of the advertisement, its wide exposure, and the name of the appellant combined to create an irresistible impression that it was promotional material designed to advance the course of cigarette smoking and to assist in the sale of cigarettes.*

49. Our clients consider that, like the Tobacco Institute's advertisement, APPEA's "future of gas" advertising campaign seeks to allay fears held by the public as to the significant quantities of greenhouse gases emitted by the extraction, processing and end-use of fossil gas, and the significant environmental harm caused as a result. Like the Tobacco Institute, APPEA (constituted of its members) has a commercial interest in assuaging community concerns about the environmental harm caused by fossil gas; its "future of gas" campaign is intended to protect the commercial interests of the gas industry by refuting criticism of its product.

50. In *ACCC v Homeopathy Plus! Australia Pty Limited* [2014] FCA 1412, the respondent sold homeopathic products and treatments through its website. The purpose of the respondent was to advocate for homeopathy and lobby the government for changes in attitudes towards it. Articles were published on the respondent's website, which included statements about the effectiveness of the whopping cough vaccine. The respondent's defence included that the statements were not made in trade and commerce but "were uploaded for general information and education purposes and were a contribution to the ongoing public debate of scientific and political interest which is an activity regularly undertaken by [Homeopathy Plus]".[49]

51. In relation to the issue as to whether the conduct was in trade or commerce, Perry J said at [305] – [306] that it does not turn on whether the statements were made for the purpose of making a profit and that:

> *… the fact that an activity may be political in the sense of advocating for a change of policy (or equally, that it is educational) does not necessarily mean that the activity is not in trade or commerce.*

52. As such, our clients consider that the "future of gas" campaign was in trade or commerce since its purpose is to protect the commercial interests of the gas industry from increased public criticism as to its environmental impacts, which could affect continued investment in its product.

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[49] *ACCC v Homeopathy Plus! Australia Pty Limited* [2014] FCA 1412 [17] (Perry J).

Misleading or deceptive

53. For the reasons set out above, our clients consider that the Representations are likely to mislead the relevant class of person.

Request to Investigate

54. For the reasons set out above, and given the ongoing nature of APPEA's conduct, our client requests the ACCC investigate the concerns raised by our clients and take such compliance action as is deemed appropriate.

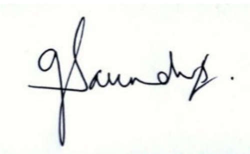
55. Our clients consider that an investigation into APPEA's behaviour is aligned with the ACCC's investigation into industry or sector environmental and sustainability claims that may be false, misleading, or have no reasonable basis, often referred to as 'greenwashing'.[50]

56. If you have any further queries, please do not hesitate to contact Kirsty Ruddock by email on kirsty.ruddock@edo.org.au.

Yours faithfully

Environmental Defenders Office

Kirsty Ruddock
Managing Lawyer
Safe Climate (Corporate and Commercial)



Clare Saunders
Solicitor
Safe Climate (Corporate and Commercial)

[50] ACCC Greenwashing by businesses in Australia (accessed 29 June 2023).

Annexure A

Statements by APPEA

Source	Statement
The overall emissions intensity of gas is 50% that of coal.	
Website[51] YouTube[52]	"Gas is 50% cleaner than coal."
Gas is replacing coal's share of electricity generation in Australia	
Website, YouTube	'As Australia shuts down coal, gas is picking up the load.'
Opinion Piece[53]	'Natural gas will be part of that journey: making bricks that build Australia, reducing emissions by replacing coal in electricity."
Opinion Piece	'This is the role of gas in electricity in the cleaner energy future. And other states which still rely heavily on coal-powered generation will move in this direction as coal exits the system.'
Gas generates 20% of electricity used in Australia	
Website	'About a fifth of the electricity we use is made by natural gas.'
Gas represented 27% of Australia's residential energy consumption in 2020-2021	
Website	'Over and above its role in electricity generation, over 5 million homes use gas directly every day. Showering, Cooking, warming us in winter and fueling out beloved BBQ. What you might now know is that 27% of Australia's domestic energy consumption in 2020-21 was gas.'
APPEA is committed to achieving net zero emissions by 2050.	
Opinion Piece	"We share Australia's commitment to net zero across the economy by 2050"
The production of blue hydrogen releases low levels of carbon dioxide into the atmosphere.	
Opinion Piece	"The gas industry is also key to deploying net zero technologies such as low-carbon hydrogen production and carbon capture and storage facilities, which trap carbon and bury emissions deep underground."

[51] https://futureofgas.com.au/.

[52] https://www.youtube.com/@APPEALimited/videos.

[53] Opinion Article: APPEA Chief Executive Samantha McCulloch on the importance of gas to Australia and net. zero (Herald Sun, Adelaide Advertiser, West Australian) | APPEA.

Annexure B

YouTube screengrab

(as at 14 June 2023)

Annexure B

APPEA –YouTube advertisement (as at 14/6/2023)

Found at: https://www.youtube.com/@APPEALimited/videos

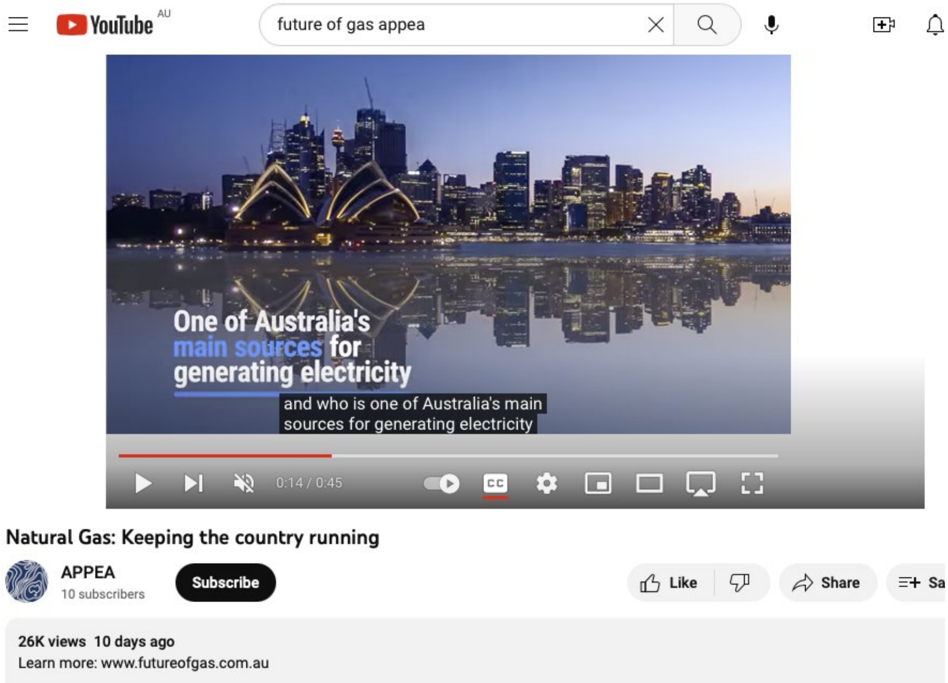
Natural Gas: Keeping the country running (45 sec)

Who keeps this running day and night? [Image description: Ambulance pulling into an emergency department at night, staff working on a patient] [Image text: Medical Supplies]

And this [Image description: Two people in blue shirts with black caps on. One person is in a refrigerated truck passing a box of apples to the other on the ground] [Image text: Refrigerated Trucks]

Who keeps businesses like these running all around the country? [Image description: greenhouses, breweries, glass making, brick making] [Image text: Greenhouses, Breweries, Glass making, Brick making]

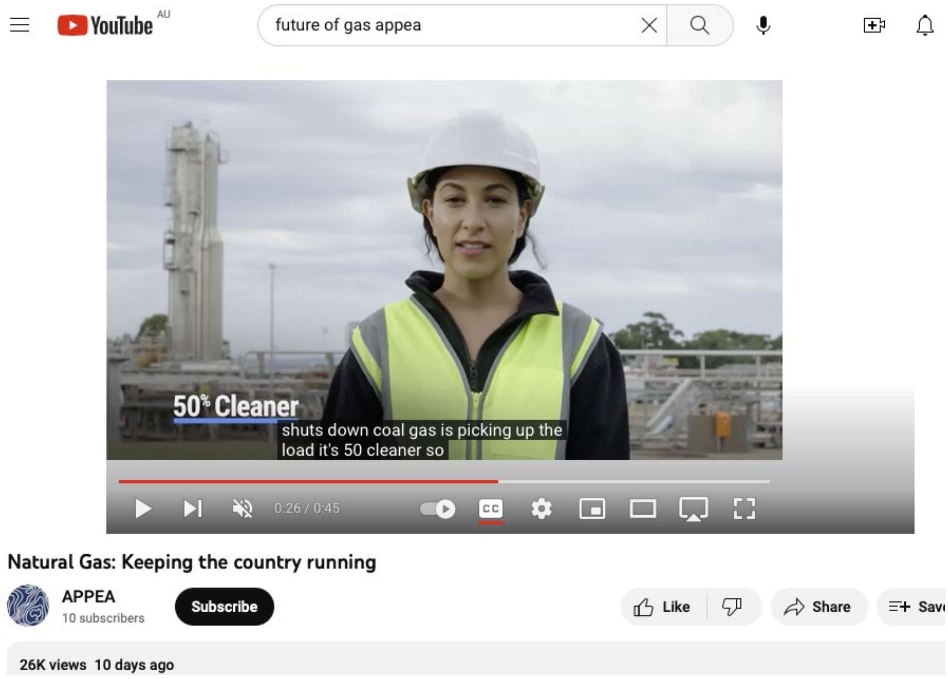
And who is one of Australia's main sources for generating electricity? [Image description: Sydney city view from day to night] [Image text: One of Australia's main sources for generating electricity]

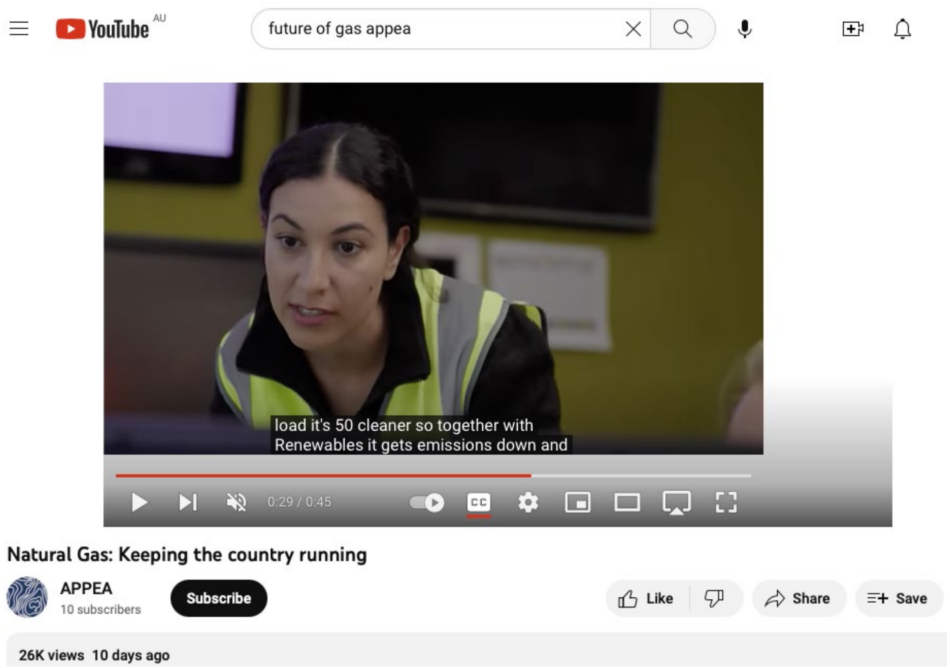


It keeps the lights on. [Image description: Sydney city view at nighttime]

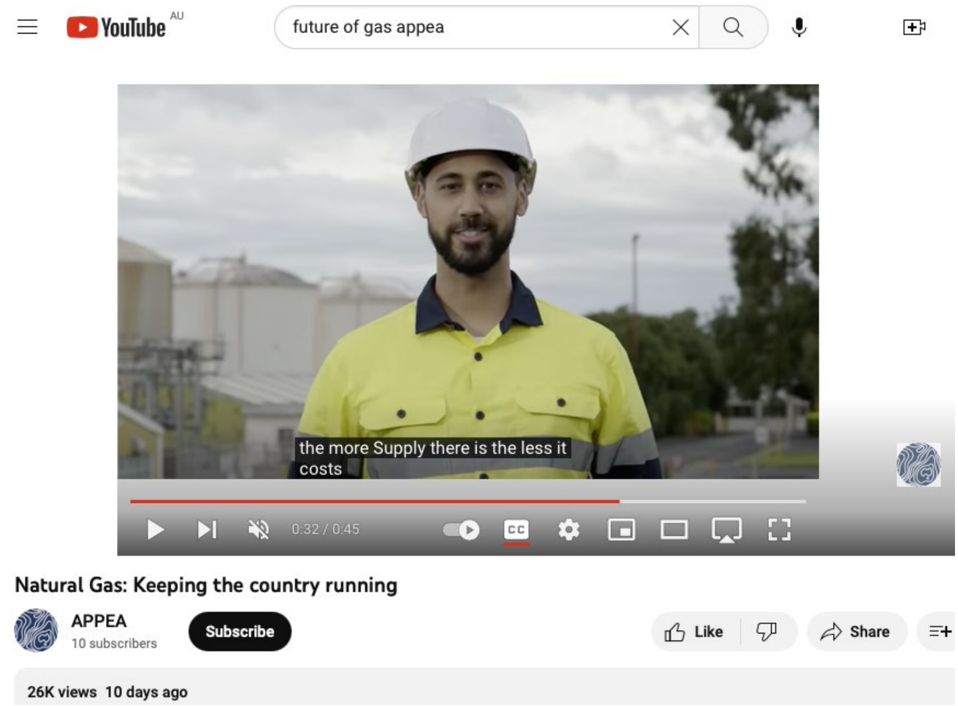
We are. They all run on Australian Natural Gas. As Australia shuts down coal, gas is picking up the load. [Image description: Two people in front of a factory. One in a yellow high-vis jacket and white hard hat. One in blue shirt, orange high-vis vest and yellow hard-hat] [Image text: Australian Natural gas]

It's 50% cleaner. So together with renewables, it gets emissions down. [Image description: First shot of a person in high-vis vest in front of a factory, second shot of two people behind a control panel with multiple screens of information above] [Image text: 50% cleaner]





And the more supply there is, the less it costs. [Image description: Person wearing high vis shirt and white hard hat in front of a factory]



It'll help keep Australia running as we transition to a cleaner future. [Image description: Person in blue shirt, orange high-vis vest and yellow hard hat] [Image text: A cleaner future]

Music. [Image description: blue flame] [Image text: Natural Gas. Keeping the country running]

Authorized by S. McCulloch, APPEA Limited, Canberra [Image description: plain background] [Image text: Authorized by S. McCulloch, APPEA Limited, Canberra]

Annexure C

Climate Analytics: Factchecking the APPEA

Bill Hare (8 June 2023)

Briefing

Factchecking the APPEA

By Bill Hare, Climate Analytics CEO and Senior Scientist

8 June 2022

The Australian gas industry, specifically its industry body, the Australian Petroleum Production and Exploration Association (APPEA) has launched an expensive advertising campaign to lobby for more gas use in Australia.

This briefing sets out their arguments, says why they're wrong, and provides a factual counter to them.

APPEA has made a large number of hyperbolic claims including:

"If we removed gas-related products, so much of what we rely on everyday would disappear: beer bottles, the bricks that build our homes, glass in buildings, packaging and paper as well as fertilisers for agriculture."

These claims do not stack up and appeared designed to frighten people rather than to deal with the real challenges of the net zero transition.

APPEA argues that "*Natural gas is keeping Australia running on the path to net zero*" when in fact growth in the use of gas will block the pathway to net-zero.

APPEA claim: Gas is a transition fuel

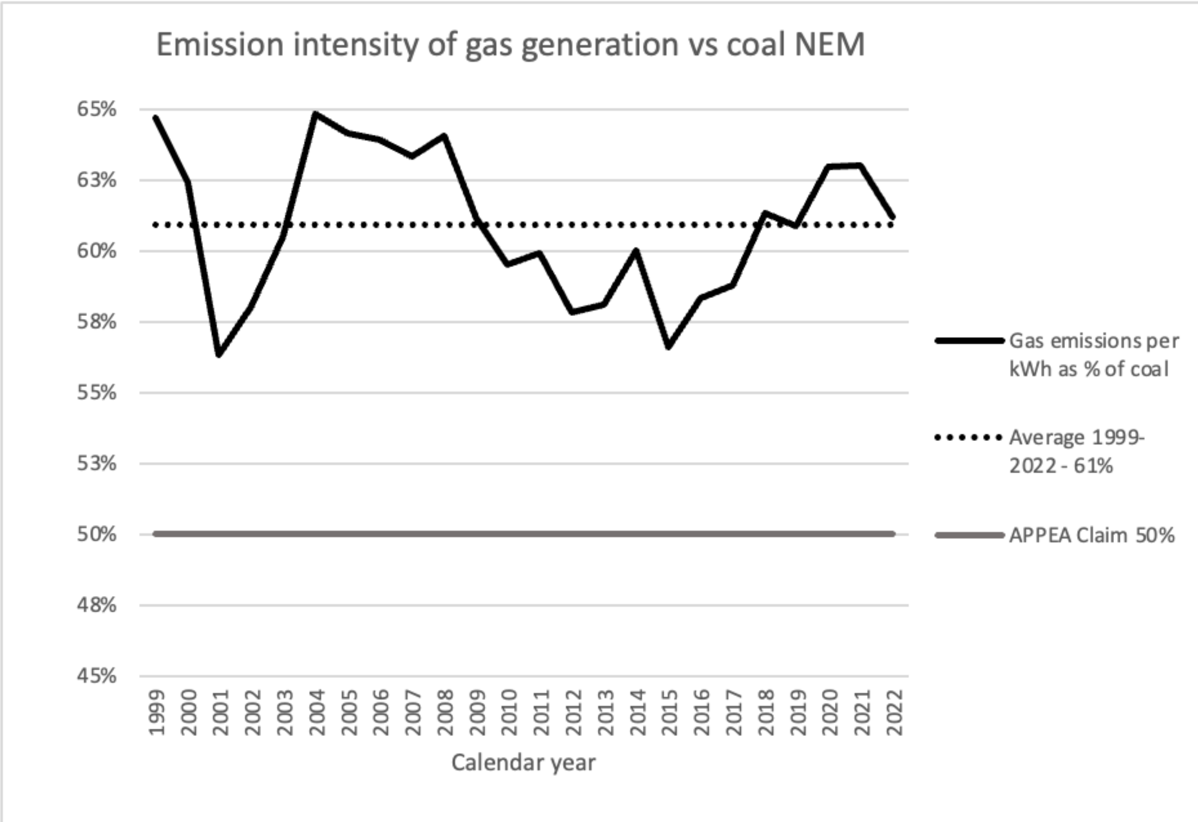
Wrong. Gas is a fossil fuel, and when it burns, it emits greenhouse gases. Our analysis, and others including the IPCC and IEA, shows that the role for gas is dwindling as economies decarbonise - and that for the world to be able to limit warming to 1.5°C there should be no new gas exploration, and production needs to be phased out fast.

Instead, we need to be doubling down on the rollout of renewables. We're running out of time to get emissions down far enough to slow the pace of climate change to something we can manage.

It would be counterintuitive and counterproductive to expand a polluting and expensive form of energy like gas. Investments in gas now will either create significant carbon lock in, or creating stranded assets.

APPEA claim: Gas is 50% cleaner than coal

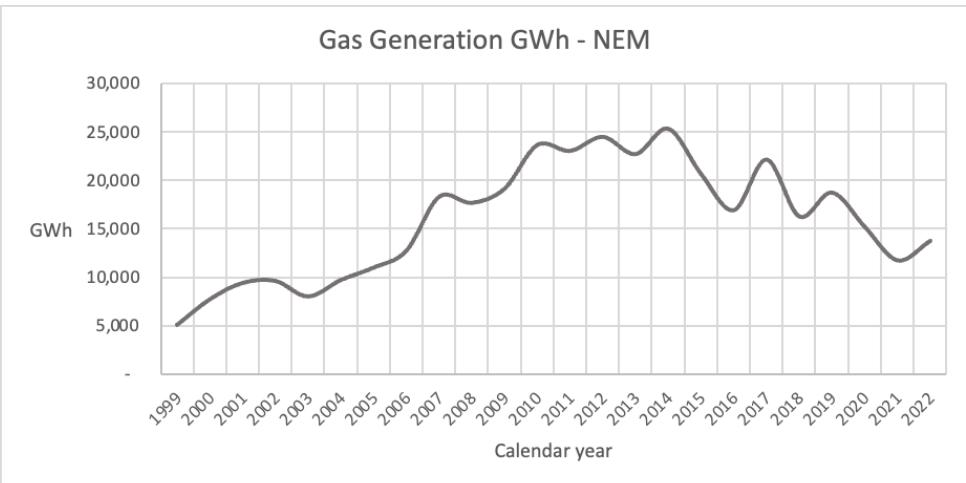
Data for the National Energy Market (NEM) shows that that average GHG emissions per unit of gas generation is 61% of that from coal, substantially higher than that claimed by APPEA.



Source: Calculate from calendar year data for generation and GHG emissions 1999-2022 from OpenNEM at https://opennem.org.au/energy/nem/?range=all&interval=1y

APPEA claim: *Gas is one of Australia's main sources for generating electricity*

Data for the National Energy Market (NEM) shows that gas generation peaked in about 2014 and is now about 45% below 2014 levels. In 2014 it was about 13% of generation but is now only about 7% in the NEM.

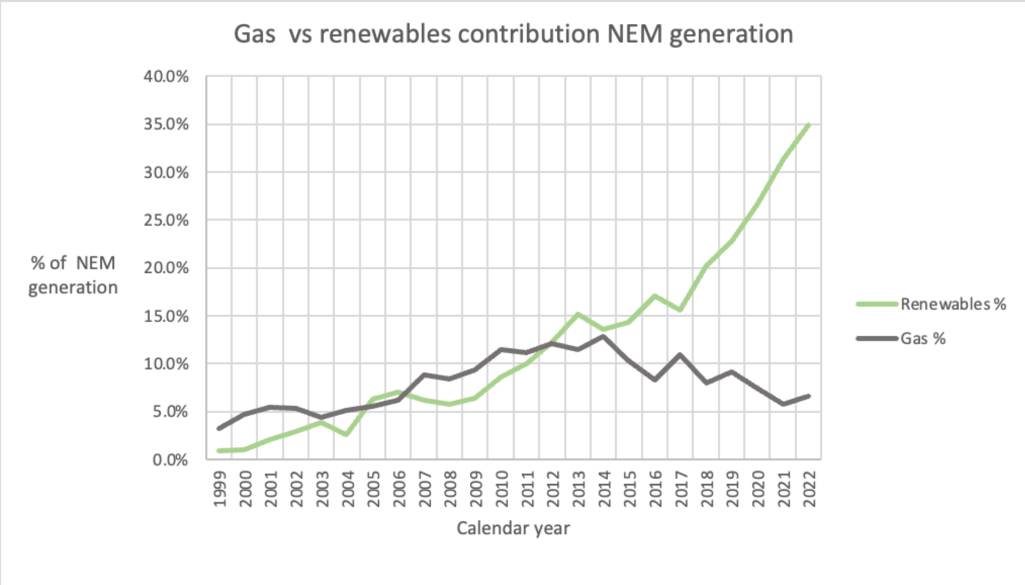


Source: https://opennem.org.au/energy/nem/?range=all&interval=1y

APPEA claim: *"natural gas partners with renewable energy to support renewables when the sun doesn't shine, or the wind doesn't blow"*

Data from National Energy Market (NEM) shows that total gas generation has declined by about 50% since 2014 as renewables have grown to about 35% of generation in 2022 from about 12-14% in 2014.

Power companies are finding that big batteries and storage are out competing – "cannibalising" – their gas generating units



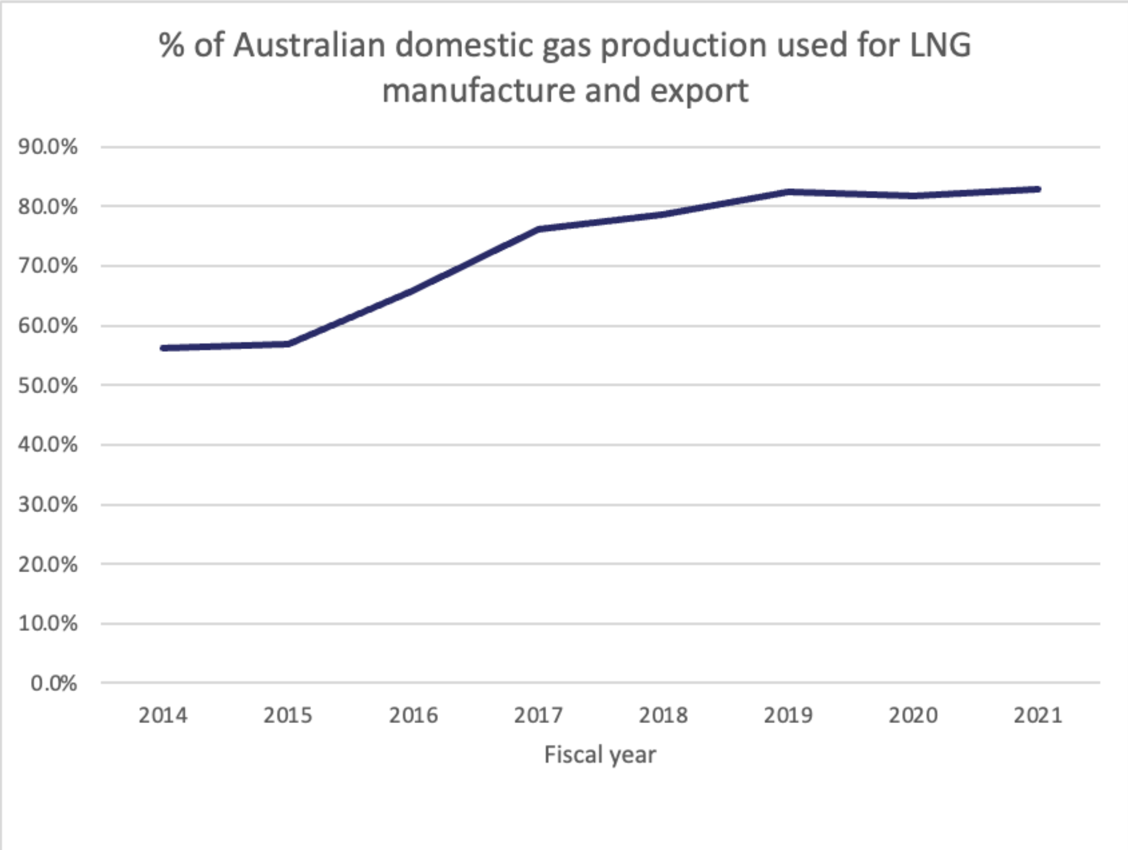
Source: https://opennem.org.au/energy/nem/?range=all&interval=1y

APPEA claim: *"Gas met 27% of Australia's energy needs in 2020-1"*

This is not the whole story and significantly exaggerates the role of gas in Australia's domestic economy. We step through the reasons.

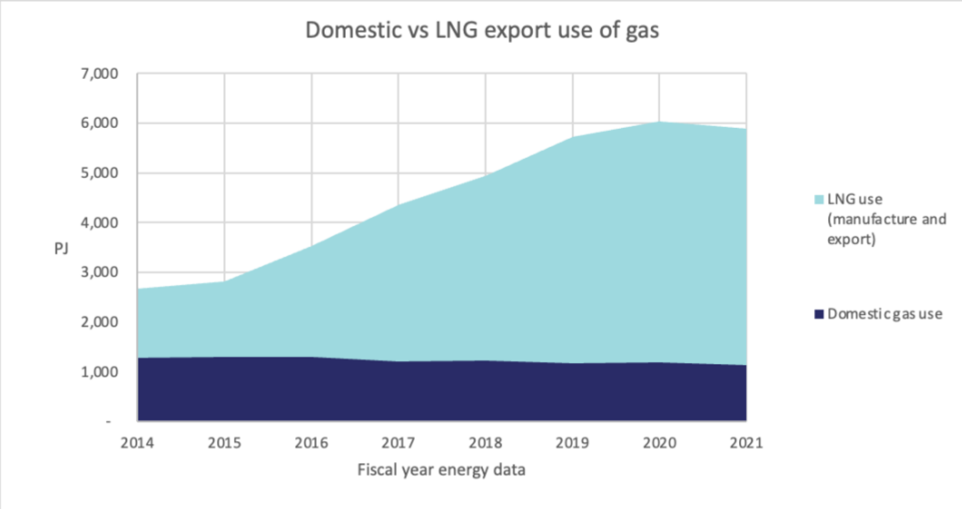
LNG manufacture and export accounts for most of the gas use in Australia –83% of Australian gas production went to the manufacturing and export of LNG in 2020/21[1].

[1] Australian Energy Update 2022, Figure 3 Australian natural gas flows, petajoules, 2020–21 and Table A Australian energy supply and consumption, 2020-21. https://www.energy.gov.au/publications/australian-energy-update-2022



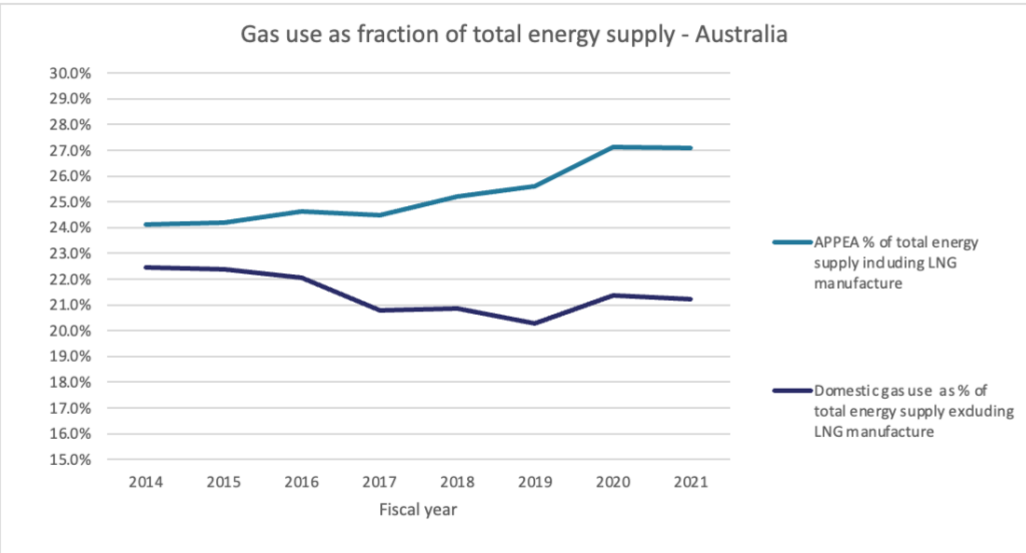
Source: Table A from Australian Energy Updates for years 2014/15 to 2020/21 inclusive from Australian production and exports of gas, and gas use for LNG manufacture from Australian natural gas flows data. Gas equivalent to about 10% of the exported gas volume is used to manufacture LNG in Australia. https://www.energy.gov.au/publications/australian-energy-update-2022

Whilst domestic use of gas has slowly declined over the period 2014 -2021, the use of gas for LNG manufacture and export has grown massively.



Source: Table A from Australian Energy Updates for years 2014/15 to 2020/21 inclusive from Australian production and exports of gas, and gas use for LNG manufacture from Australian natural gas flows data. Gas equivalent to about 10% of the exported gas volume is used to manufacture LNG in Australia. https://www.energy.gov.au/publications/australian-energy-update-2022

Taking LNG exports into account gives a very different picture of the contribution of gas to Australia's total primary energy supply. Using the biased APPEA approach this has increased to 27%. If export use of gas is factored out the fractional contribution of gas has declined towards 21%.



Source: Table A from Australian Energy Updates for years 2014/15 to 2020/21 inclusive from Australian production and exports of gas, and gas use for LNG manufacture from Australian natural gas flows data. Gas equivalent to about 10% of the exported gas volume is used to manufacture LNG in Australia. https://www.energy.gov.au/publications/australian-energy-update-2022

APPEA and the gas industry argue that LNG is a low carbon fuel and can be used to displace coal in Asian markets.

Independent research shows two key things.

First, LNG is a very carbon intensive fuel source and taking into account emissions in production, manufacture distribution and gasification, including methane leakages, may have a greater GHG footprint than coal-fired generation when used for power production.

Second, APPEA and the industry, including Woodside Energy, claim LNG will reduce emissions in Asia by displacing coal. CSIRO analysis (commissioned by Woodside but not released at the time), and our @CA_latest analysis show this is not the case and instead renewables and efficiency are the approach to take.

APPEA makes strong and hyperbolic claims as to the importance of gas for economic activities but does not at all discuss the potential for replacement of gas through efficiency and electrification. All sectors have opportunities to replace gas, including those that are most carbon intensive, through improved efficiency, changes in processes and electrification with renewable power.

To unpack this, it is best to start with the present energy data for gas use in Australia – the real facts. This shows the LNG industry is the largest gas consumer with close to 28% of consumption. Electricity generation (not including LNG plant) accounts for about 27%, and as seen above this use is declining.

The next biggest sector is residential use for cooking, heating, and hot water, which used close to 11% of gas in 2020/21. Rewiring Australia has shown that households will be far better off replacing these gas using appliances with electric stoves, heat pumps and solar PV.

Rewiring Australia says: "It's half the running costs of a fossil fuel home and it's how we'll have the biggest impact on climate this decade".

Mining activities accounted for about 4% of gas used in Australia – the mining industry is working on decarbonising which means replacing gas for power generation and renewables and storage.

In the Australian energy accounts, gas used in LNG manufacture is assigned to the mining category and gas used in power generation in LNG plant is assigned to electricity sector – this gas needs to be factored out to get the full picture of gas use in the LNG sector as well as a fair picture for the other sectors.

Rank	Sector (1)	PJ	% of 2020/21 gas use	Cumulative
1	LNG manufacture (2)	433.0	27.6%	27.6%
2	Electricity generation (not including in LNG plant)	428.2	27.3%	54.9%
3	Residential	165.8	10.6%	65.5%
4	Non-ferrous metals	134.6	8.6%	74.1%
5	Chemical	125.3	8.0%	82.1%
6	Mining (excluding LNG)	68.8	4.4%	86.4%
7	Other industry	50.9	3.2%	89.7%
8	Energy conversion	46.0	2.9%	92.6%
9	Commercial and services	43.3	2.8%	95.4%
10	Food, beverages, textiles	37.6	2.4%	97.8%
11	Wood, paper and printing	11.4	0.7%	98.5%
12	Iron and steel	10.0	0.6%	99.1%
13	Petroleum refining	5.0	0.3%	99.5%
14	Transport	3.0	0.2%	99.7%
15	Construction	2.7	0.2%	99.8%
16	Water and waste	1.4	0.1%	99.9%
17	Agriculture	1.2	0.1%	100.0%
	Total	1568.2	100%	
	Sources: (1) Australian energy statistics, Table A2, Australian energy supply and consumption, 2020-21 (2) Australian Energy Update 2022, Figure 3 Australian natural gas flows, petajoules, 2020–21, https://www.energy.gov.au/sites/default/files/Australian%20Energy%20Statistics%202022%20Energy%20Update%20Report.pdf LNG exports were estimated at 4,314 PJ, with LNG plant using 433 PJ (10% of exported volume) to manufacture this of which 95 PJ went to power generation and 338 PJ direct use.			

APPEA claim: *"Natural gas is essential for producing food and beverages, as it provides energy for baking, cooking, refrigeration, and sterilisation in the food processing industry."*

Gas used in food, beverages and textiles in 2020/21 but was only 2.4% of national gas use. Nevertheless gas use is at present important accounting for about 25% of final energy use, however biofuels account for over 50% of final energy use and electricity

15%. Efficiency, electrification, and renewables can substantially replace gas use in this sector, which is suffering from high gas prices in Australia.

APPEA claims gas is needed as a "*fuel for transportation within manufacturing facilities, powering forklifts, trucks, and other internal logistics vehicles*".

But gas used in transport account for only 0.2% of gas use in Australia. And by now, nearly everyone, except APPEA it seems, understands that all these applications can be electrified over time.

APPEA also focuses on paper, claiming that without gas, packaging and paper could "disappear".

The first thing to note is that gas use for wood, paper and printing gas use is only 0.7% of gas use nationally – gas use for LNG is 38 times greater. Within the sector gas use accounting for about 22% of final energy use, however biofuels account for over 39% of final energy use and electricity 27%. There are many opportunities to cost- effectively reduce gas use over time in this sector.

Sectors that are harder to abate including chemicals, non-ferrous metals, iron and steel, and other industry account for about 20% of gas use in Australia, and gas is a critical source of energy for the sectors, accounting for about 48% of final energy use.

However, in each of these industries it has been shown that there are cost effective solutions to significantly reduce fossil fuel use, including gas and replace it with electrification, efficiency and in a number of cases green hydrogen or ammonia. This is likely to take longer to achieve then the reduction is possible in the other sectors but can still yield substantial reductions even by 2030 and doing so will create many new jobs.

"Heavy industry in Australia could decarbonise, help limit warming to 1.5 degrees and create up to 1.35 million jobs: new report outlines pathways": Source

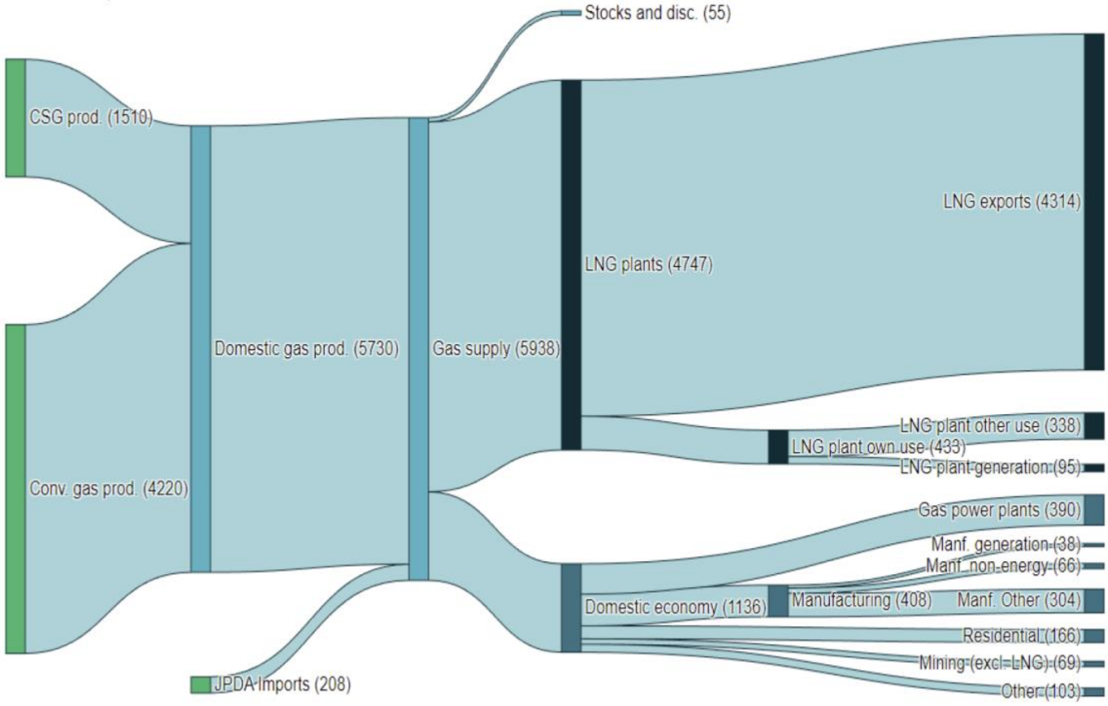
APPEA particularly singles out fertiliser for its hyperbolic scare campaign saying *that "If we removed gas-related products, so much of what we rely on everyday would disappear: ...as well as fertilisers for agriculture."*

This is complete nonsense. Green fertiliser plant are beginning to be built, including in QLD and whilst not reducing emissions to zero are making a large step towards very substantial reductions.

One of the world's largest fertiliser manufacturers Yara has announced that it will be progressing towards green fertiliser.

"This year, Yara will introduce fossil-free, green fertilizers that are produced using renewable electricity instead of fossil fuels. These fertilizers will be predominantly made from water and air, resulting in an 80-90 percent reduction in carbon emissions compared to fertilizers made with natural gas."

Finally, an important figure that everyone should understand about gas use in Australia is to be found in the Australian Energy Update each year which shows where gas goes from production to final use.



Note: Components may not sum due to rounding

Source: Department of Climate Change, Energy, the Environment and Water (2022) Australian Energy Statistics, Tables A and F and internal sources

Source: Australian Energy Update 2022 Figure 3 [Australian natural gas flows, petajoules, 2020–21]

Annexure D

IEEFA: Gas' Role in the Transition

Bruce Robertson (May 2023)

Institute for Energy Economics and Financial Analysis

Gas' Role in the Transition

A Fuel Transitioning Out of the Energy System

Bruce Robertson, Energy Finance Analyst Gas/LNG

May 2023

Key Findings

Gas usage for gas-powered electricity generation in Australia has collapsed.

Gas usage for electricity generation has almost halved in recent years dropping 47% from 2012 – 2022 and is expected to drop a further 34% to 2030.

The amount of gas we will need for electricity generation by 2030 is very small, at just 4% of forecast production on the east coast of Australia.

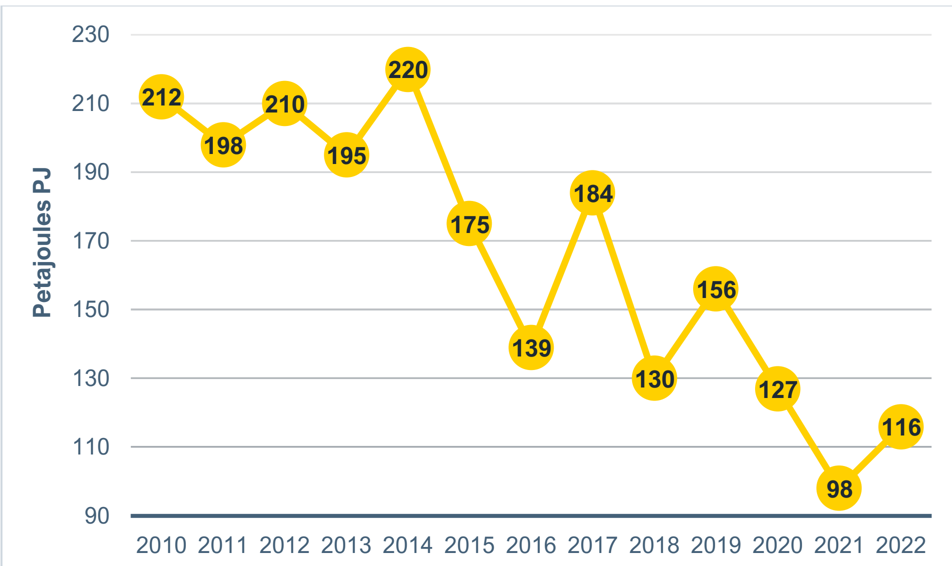
Gas is a fuel transitioning out of the energy system.

Executive Summary

Gas usage for gas-powered electricity generation in Australia has collapsed.

Between 2014 and 2022, gas usage for gas powered generation fell by 47%. A market that virtually halves in just eight years is usually termed a collapse.

Figure 1: Gas-Powered Generation – Annual Gas Usage



Source: Australian Energy Market Operator (AEMO).

By 2030, the Australian Energy Market Operator (AEMO)forecasts gas usage for electricity generation will fall a further 34% to just 76 petajoules from 116PJ in 2022. AEMO forecasts demand will suffer a further collapse in that period.

This paper will seek to explain how gas usage for gas-powered generation is suffering a collapse on top of a collapse.

Gas Is a Transition Fuel?

The peak gas lobby group, the Australian Petroleum Production & Exploration Association (APPEA), has consistently stated for many years that gas is
a transition fuel:

"Our transition to cleaner energy is at risk because of a shortage of a fossil fuel: natural gas.

"Or, to put it another way, we need more gas because we need more renewables.

"People willing to think about the nuts and bolts of decarbonising Australia's generation sector know that a cleaner sector means, for many years, more gas-fired generation."[1]

This refrain of, "We need more gas to fire gas power stations in a renewables-rich grid" has been faithfully repeated by the Prime Minister[2] [3] and the Energy Minister.[4]

We do not need more gas for the transition; we need much less gas in a renewables-rich grid.

This paper will demonstrate that the amount of gas needed in the energy transition is very small and shrinking.

Gas Usage for Power Generation and Renewables

The Current Situation

From 2014-2022, renewables increased their share of electricity generation strongly while gas usage in gas-powered generation nearly halved.

In 2014, renewables comprised less than 14% of the electricity generated in the National Electricity Market (NEM), which covers the eastern states of Australia. Last year, renewables accounted for nearly 35% of electricity generated.[5] While renewables' share of generation has gone up 2½ times, gas usage for gas-fired generation in the NEM has nearly halved.

The AEMO Forecasts

The government has clear ambitions to transform Australia's grid into a renewables-rich grid, taking the share of generation from 35% renewables in 2022 to 82% renewables by 2030.[6]

With renewable generation expanding rapidly, AEMO forecasts large falls in gas usage from 116PJ in 2022 to just 76PJ in 2030.[7]

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[1] APPEA. Road to renewable energy goes via the nation's gas fields. 27 December 2016.
[2] Australian Financial Review. Gas has a key role in energy transition. 6 March 2023.
[3] Australian Financial Review. Greens' gas objections impede clean energy transition: PM. 7 March 2023.
[4] Australian Financial Review. Bowen defends need for future gas supply as Labor pushes Greens. 13 March 2023.
[5] National Energy Market. OpenNEM energy consumption statistics 1998-2023.
[6] The Conversation. To hit 82% renewables in 8 years, we need skilled workers – and labour markets are already overstretched. 18 August 2022.
[7] AEMO. Forecasting Data Portal

The Answer to Gas and the Transition Is 4%

While demand for gas for gas-powered generation will collapse by 2030, overall gas production on the east coast of Australia is expected to decline only marginally.

The net result is that a very small amount of overall production is needed for the transition to a renewables rich grid.

Only 4% of total east coast gas production will be used for gas-powered generation in 2030, AEMO forecasts.[8]

The Need for Gas-generation Capacity

If we are to get to 82% renewable generation by 2030, as the government aims to do, many believe there is a need for more gas-peaking capacity. AEMO calls for an increase in gas-fired peaking plants from 7GW capacity now to 10GW capacity in 2050 in its Integrated System Plan (ISP).[9]

So how can gas demand for gas-powered generation be collapsing when gas-peaking plant capacity is rising with the need to back up renewables?

The answer is quite simple: APPEA is intentionally conflating an increase in gas-peaking capacity with an increase in gas demand from electricity generation. It is doing this to deceive the public into believing we need more gas in a renewables-rich grid. Quite simply we don't. We need less gas to run a renewables-rich grid.

Gas demand for electricity generation has fallen, and will continue to fall, for two basic reasons:

- Gas baseload plants are closing. Gas is too expensive in Australia to use for baseload generation. Gas baseload plants use a lot of gas as they operate for most of the time;
- Gas-peaking plants simply don't operate very often. Typically, gas-peaking plants will operate for 4-14% of the year.[10]

High gas-consuming gas baseload plants are shutting, and some heavily government subsidised gas-peaking plants are opening that will not consume much gas.

While we will need some gas-peaking capacity, it will not operate very often, leading to low gas consumption.

[8] AEMO. Forecasting Data Portal. 21 April 2023.
[9] AEMO. Integrated System Plan 2022. Page 11
[10] National Energy Market. OpenNEM. 2023

Batteries – Direct Competition to Gas

Increasingly, it is being recognised that grid-scale batteries pose a major threat to gas-peaking plants.

Batteries have totally different economics to gas plants. Those that operate in the merchant market will use their capacity every day. Batteries have high up-front capital costs but very low operating costs. They will therefore operate every day, filling at the cheap prices of the day and typically selling into the evening peak periods. Their economics rely on the difference between the price they buy electricity and the price they sell electricity. This is in contrast to gas-peaking plants, which can only operate at very high electricity prices as they struggle to compete with very high domestic gas prices in Australia.

Batteries have rapidly grown in scale. Grid-scale batteries arrived in Australia in November 2017, with the construction of the Hornsdale power reserve in South Australia.[11] The battery was a 100MW/129MWh. It was upgraded in September 2020 to 150MW/193.5MWh.

It has since been dwarfed by other projects, such as AGL's big battery project at Torrens Island in SA. The 250MW big battery, sized initially at one-hour storage (250MWh), is likely to expand to up to four hours storage (1,000MWh).[12]

In December 2021, the Victorian Big Battery opened in Geelong. The 300MW/450MWh facility is the biggest completed battery storage installation in Australia.

Even bigger batteries are planned by AGL, with a 500MW battery for the Liddell site following the closure of its 52-year 1,500MW Liddell coal-fired power station in April, and Origin Energy plans a 700MW battery for its Eraring site,[13] where it intends to close its 2,992MW coal-fired power plant in 2025.[14]

The increasing scale and number of grid-scale batteries will crimp demand for gas.

Grid-scale battery technology is attracting large investment.[15] Technological advances in batteries could spell the demise of gas much faster than any current forecasts for the industry.

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11 Hornsdale Power Reserve.
12 Reneweconomy. AGL begins process of powering up Torrens Island battery, biggest in South Australia. 17 November 2022.
13 Australian Financial Review. AGL Energy given green light for 500MW Liddell battery. 20 March 2022.
14 Origin Energy. Eraring Power Station.
15 Bloomberg. Lithium-ion Battery Pack Prices Rise for the First Time to an Average of $151/kWh. 6 December 2022.

Conclusion

Gas consumption for gas-powered generation has collapsed and will continue to collapse as the electricity system changes to a renewables-rich grid.

The amount of gas we will need for electricity generation by 2030 is very small, at just 4% of forecast production on the east coast of Australia.

We are being misled by our government and the oil and gas industry, telling us we need more gas and more gas fields for the transition. We don't.

The gas industry does not have a supply problem, it has a demand problem. Gas is a fuel transitioning out of the energy system.

Appendix 1 - Gas-powered Generation Gas Consumption by State (TJ/day)

	NSW/ACT	QLD	VIC	SA	TAS	Total
2014-15	76.3	334.3	43.0	120.0	0.5	574.0
2015-16	81.0	220.8	33.5	129.5	18.3	483.0
2016-17	56.8	170.3	53.5	155.0	16.3	451.8
2017-18	46.8	141.0	88.5	186.8	18.0	481.0
2018-19	29.8	113.0	76.3	175.3	11.5	405.8
2019-20	43.5	133.8	69.8	157.3	3.3	407.5
2020-21	20.8	126.0	37.0	129.5	2.8	316.0
2021-22	51.3	122.0	44.3	98.5	1.5	317.5
2022-23 (YTD)	31.3	107.0	38.0	83.7	2.7	262.7

Source: Australian Energy Regulator.

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Annexure E

‘Clean’ hydrogen? – Comparing the emissions and costs of fossil fuel versus renewable electricity based hydrogen.

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'Clean' hydrogen? – Comparing the emissions and costs of fossil fuel versus renewable electricity based hydrogen

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HIGHLIGHTS

- Emissions from gas or coal based hydrogen systems are substantial even with CCS.
- Fugitive emissions are rarely included in national and international H2 strategies.
- CCS is an expensive option for decarbonising hydrogen production.
- Electrolysis with renewable energy could become cheaper than fossil fuels with CCS.

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ABSTRACT

Hydrogen produced using fossil fuel feedstocks causes greenhouse gas (GHG) emissions, even when carbon capture and storage (CCS) is used. By contrast, hydrogen produced using electrolysis and zero-emissions electricity does not create GHG emissions. Several countries advocating the use of 'clean' hydrogen put both technologies in the same category. Recent studies and strategies have compared these technologies, typically assuming high carbon capture rates, but have not assessed the impact of fugitive emissions and lower capture rates on total emissions and costs. We find that emissions from gas or coal based hydrogen production systems could be substantial even with CCS, and the cost of CCS is higher than often assumed. Carbon avoidance costs for high capture rates are notable. Carbon prices of $22–46/tCO2e would be required to make hydrogen from fossil fuels with CCS competitive with hydrogen produced from fossil fuels without CCS. At the same time there are indications that electrolysis with renewable energy could become cheaper than fossil fuel with CCS options, possibly in the near-term future. Establishing hydrogen supply chains on the basis of fossil fuels, as many national strategies foresee, may be incompatible with decarbonisation objectives and raise the risk of stranded assets.

1. Introduction

Hydrogen has the potential to become a globally traded, emissions-free energy carrier, which could help enable deep decarbonisation of industry, transport and the wider energy sector [1,2]. Global momentum to develop a hydrogen economy has never been stronger, and there has been a proliferation of national hydrogen strategies and international reports [3]. Some of the enthusiasm for hydrogen is based on declines in the cost of renewable energy and electrolysers [4], but there is also support for scaling up traditional methods of producing hydrogen from fossil fuels with carbon capture and storage (CCS). Residual CO_2 emissions after CCS beg the question whether this is consistent with global decarbonisation objectives.

Carbon capture is a mature technology used in a range of industries, but the costs and CO_2 emissions reduction potential vary widely, and are difficult to define in some cases. The amount of CO_2 captured depends

; GHG, greenhouse gas; CCS, carbon capture and storage; CCU, carbon capture and use; IEA, International Energy Agency; IRENA, International Renewable Energy Agency; LHV, lower heating value; SMR, steam methane reforming; CG, coal gasification; PV, photovoltaic; LCOE, levelised cost of electricity; PEM, polymer electrolyte membrane; PC, production cost; EC, electricity cost; CC, capital cost; CF, capacity factor; OLS, ordinary least squares; GWP, global warming potential; USD, US dollars; kg, kilogram; tCO2, tonne of CO2; tCO2e, tonne of CO2 equivalent; MWh, Megawatt hour; CO2, carbon dioxide.

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Table 1
Classification of national hydrogen strategies based on their treatment of 'low-emission' hydrogen technologies (using fossil fuels and incorporating carbon capture and storage) and 'zero-carbon' hydrogen technologies (electrolysers driven by zero-emission electricity).

Prioritisation of low- versus zero-emission hydrogen technologies	Strategies
Prioritises 'zero-emission' H_2	Chile France New Zealand Portugal Spain
'Zero-emission' H_2 prioritised but 'low-emission' H_2 discussed as a transitional measure	European Union Germany
Likely significant production/use of 'low-emission' H_2	Australia Canada China Japan Republic of Korea Netherlands Norway United States

not only on how and where in the process the CO_2 is captured, but also what is done with it after it is collected. Of the 21 currently operating large-scale CCS plants around the world over three quarters subsequently use the captured CO_2 for enhanced oil recovery, which means that the cost of capture can be partially offset by the sale of CO_2 [5]. However, unlike CCS, this type of carbon capture and use (CCU) can result in significant re-emission of the CO_2 into the atmosphere as enhanced oil recovery can have retention rates below 30% [6]. Carbon avoidance costs for CCS depend on the type of capture process, and include the transport and storage of captured CO_2, which is highly plant specific, as well as auditing and monitoring of capture rates and possible upstream methane or CO_2 leaks. Cost estimates for CCS usually do not always take all of these different elements into account [7,8].

The extraction and processing of fossil fuels as a hydrogen feedstock is also a source of significant emissions. This is due to the energy used during extraction and processing, and due to the direct release of natural gas into the atmosphere. Natural gas leakage, sometimes referred to as fugitive emissions, can be particularly problematic as methane is a potent greenhouse gas [9]. A recent analysis of the emissions intensity of hydrogen production in the USA considered high methane leakage rates and a 20-year global warming potential for methane. Under these assumptions, producing hydrogen from natural gas with CCS can release more greenhouse gases than burning natural gas directly [10].

In contrast, producing hydrogen with electrolysis driven by renewable energy results in no emissions. The cost of producing hydrogen with renewables depends mainly on the price of the input electricity, as well as the capital cost and load factor of the electrolyser. As renewables and electrolysers are up-scaled and deployed, the cost of this method of hydrogen production will decrease [11,12]. Unlike renewable technologies, fossil fuel methods of production are well established and unlikely to reduce in cost. They can be decarbonised with CCS but this will increase the cost of production, as reflected by carbon avoidance costs for high capture rates that are above \$80/tCO_2 [13,14].

Currently, hydrogen is predominantly used as an industrial feedstock for ammonia and for oil refining. Its production is carbon-intensive, utilising fossil fuels without CCS. The estimated 74 million tonnes (Mt) of pure hydrogen used in 2018 generated approximately 830 Mt of CO_2 emissions, or approximately 2 per cent of global greenhouse gas emissions from the energy sector [15]. With governments promoting the use of hydrogen in other sectors, including transport, demand has been projected to increase dramatically. For example, Bloomberg NEF estimates range from 187Mt to 696 Mt for 2050 based on weak and strong policy scenarios. This increases to 1370 Mt if all the 'unlikely-to-electrify' sectors in the economy were to use hydrogen [16]. Some strategies, notably those of Australia and Japan [17,18], also foresee the use and international trade of ammonia as an energy carrier; we do not explore ammonia in this paper, but broadly similar principles apply.

Scenarios for future hydrogen demand differ greatly, both in terms of final energy demand by sector and the amount of emission reductions achieved [19]. Decarbonisation can only be achieved through the use of hydrogen if the necessary expansion in its production comes from zero- or low-emission sources. Two types of low-emission hydrogen production technologies are under active consideration for early deployment: - electrolysis using zero-emissions electricity (typically renewables, possibly also nuclear), considered to have no embedded greenhouse gas emissions (other than emissions incurred in the production of equipment); and - existing fossil fuel production methods augmented with CCS, usually portrayed as 'low-emission' production. For hydrogen to play a role in the deep decarbonisation of the energy and industrial sectors, very large amounts of additional renewable energy generation and electrolyser capacity will be required. The feasibility of rapidly deploying renewable energy and electrolysers to establish a large zero-carbon hydrogen industry is unclear; however, the required rate of growth has been favourably compared to the diffusion of solar PV and offshore wind over the last decade [20]. In addition, countries with available land and high quality renewable energy resources that can produce hydrogen cheaply would need to be able to export hydrogen to countries with limited land or low solar/wind potential [15].

Some governments have given priority to the renewables electricity route in their strategies. Others make the case for a broader technology portfolio with a possibly prominent role for hydrogen from fossil fuels using CCS. These include Australia, Canada, China, Japan, Republic of Korea, Netherlands, Norway and the United States. Yet most of these strategies contain little detail of the emissions implications of CCS under real world conditions. Also, if the use of CCS does not coincide with the commencement of new fossil fuel based hydrogen supply chains then there will be a large increase in emissions during the start-up phase.

Under current carbon accounting mechanisms, potential hydrogen importers such as Japan and South Korea have little or no intrinsic incentive to buy 'zero-emissions' hydrogen or to push for high carbon capture rates. Any process emissions will occur and be accounted for in the producer countries [21]. Producer countries in turn may put the establishment of new export industries ahead of achieving lower national emissions outcomes, possibly with reference to emissions savings achieved overseas, as has been done in the case of exports of liquefied natural gas [22,23].

In Section 2 we provide an overview of the positioning of national strategies on hydrogen production technologies. We show that the overall emissions intensity of fossil fuel-based 'low-emissions' hydrogen can be substantial if moderate CCS rates and fugitive emissions are considered (section 3.1). We find that the true cost of carbon avoidance using CCS varies widely and is often not well defined, and that current CCS cost projections rely on optimistic estimates of CO_2 transport and storage, and generally do not include monitoring and verification costs. This underestimates the true cost of hydrogen production when CCS is used (section 3.2). We show that the cost of producing hydrogen via electrolysis is highly dependent on the cost of electricity as well as electrolyser costs and capacity factors (section 4). Using a range of studies and projections, we also show that renewable hydrogen production could become cost-competitive in the near future with further reductions in renewable energy and electrolyser capital costs (section 5).

2. Existing strategies and statements on 'low-emission' hydrogen

This section gives an account of the positioning of key 'low-emission' and 'zero-emission' hydrogen technologies in recent national policy statements and major reports. It draws on analysis of strategies and similar documents published by the European Union, the governments of Japan, the Republic of Korea, France, New Zealand, Australia, Norway, the Netherlands, Germany, Spain, Portugal, Chile, the United

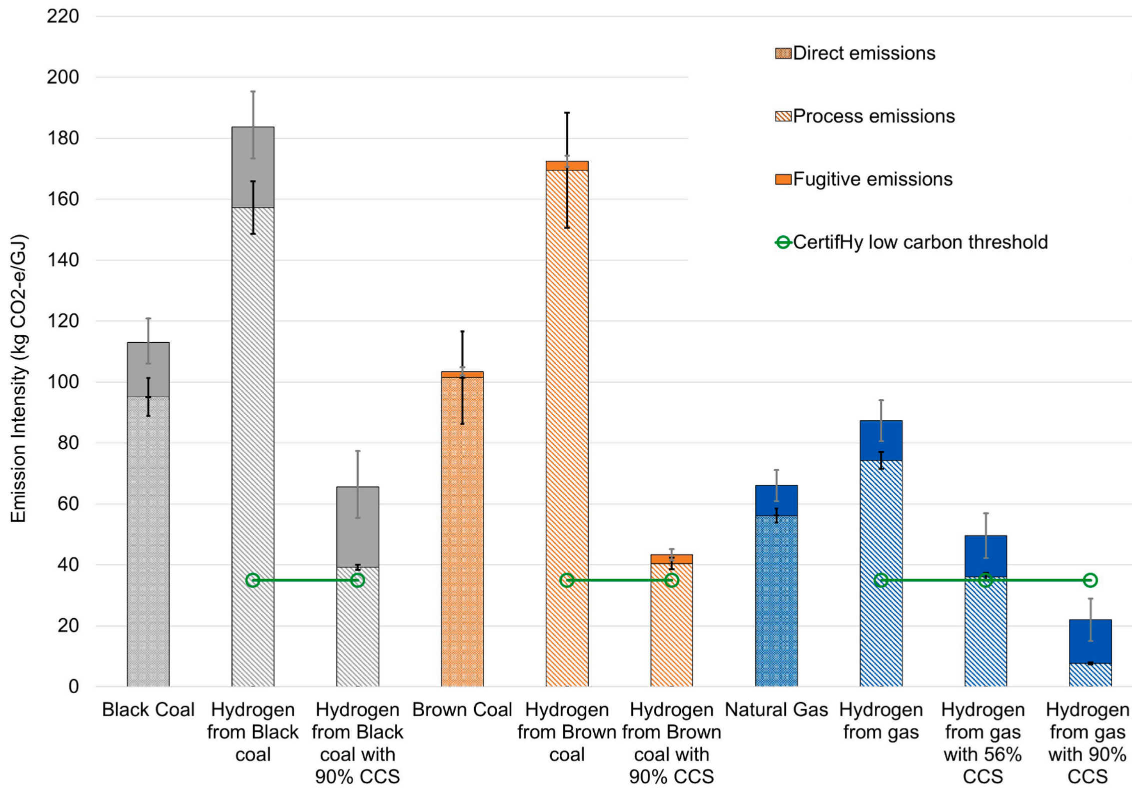

Fig. 1. Total emissions intensity of different fuels, including direct emissions from the combustion of brown/black coal and natural gas, process emissions associated with the production of hydrogen from these fossil fuels, and fugitive emissions from fossil fuel extraction. Emissions factors are taken from IPCC default data tables [41]. The error bars for direct and process emissions show the variation in emissions that occurs due to natural differences in the carbon content of fossil fuels. The error bars for fugitive emissions show the low and high values provided by the IPCC to account for global variations in fugitive emissions. Emissions from hydrogen production are also compared to the CertifHy low carbon threshold, which is defined as a 60% reduction in emission intensity below a standard steam methane reforming (SMR) production process.

States of America, China and Canada [17,18,32–35,24–31], as well as the International Energy Agency (IEA) [12] and the International Renewable Energy Agency (IRENA) [4]. Examination of these strategies shows that there is not, or not yet, international convergence around a single preferred technological approach. The IEA identifies both hydrogen from electrolysis with 'zero-emission' electricity and fossil fuel-based production with CCS as having a major ongoing role. For example, IEA projections have up to 40 per cent of global hydrogen production in 2070 from fossil fuels with CCS [15,37]. IRENA takes a contrary position, arguing that hydrogen from fossil fuels with CCS can only have a short-lived transitional role [38].

A number of national strategies focus solely on 'zero-emission' hydrogen as the preferred option (Table 1). Others, while promoting 'zero-emission' hydrogen as the superior option, support a transitional role for 'low-emission' hydrogen from fossil fuels with CCS and envisage some level of support for that. Still others are agnostic in their technology preferences, foreshadowing the likely ongoing use of 'low-emission' hydrogen as a significant component of their respective approaches. The Australian strategy professes a 'technology-neutral' approach and explicitly includes the possibility of 'low-emission' hydrogen, which it incorporates with 'zero-emission' hydrogen in its definition of 'clean' hydrogen. Norway's strategy does likewise. The Canadian strategy describes 'low-emission' hydrogen from natural gas with CCS as a primary pathway for establishing a 'clean' hydrogen industry. The strategies of Japan and Korea both refer to plans to shore up sources of hydrogen supply through investment in production, including from fossil fuels, both domestically and internationally.

Few strategies provide realistic appraisals of the likely emissions consequences of relying on the 'low-emission' option. Only Australia and Canada provide detail of expected or necessary carbon capture rates for hydrogen produced from fossil fuels to be considered 'clean'; these are at or over 90 per cent [17,35] and therefore highly optimistic as we show below. In addition, fugitive emissions from the extraction of the coal and natural gas used as a feedstock in the production of hydrogen are rarely accounted for; these are important as they can be sizeable and their global warming potential is far higher than for CO_2, as we will show in section 3. In fact, many countries' strategies effectively treat 'zero-emission' and 'low-emission' hydrogen as equivalent technological options. For example, the Japanese strategy describes hydrogen produced from fossil fuels with CCS as "carbon-free" or "zero-emission" [18]. The US Department of Energy's plan for scaling up hydrogen describes fossil fuel with carbon capture use and storage as a potential means of supplying "carbon–neutral" hydrogen [40].

It therefore seems highly likely that a significant number of countries will pursue approaches to scaling up hydrogen production, either domestically or internationally, that involve the continued use of fossil fuels. In addition, it is unclear whether the use of CCS will be introduced immediately on commencement of new fossil fuel based hydrogen supply chains, creating the possibility of highly emissions intensive production in the start-up phase. The framing of this choice in national strategies suggests there is a real risk of emissions in practice being higher than foreshadowed in such documents if governments actively encourage and support industry to move down the path of using fossil fuels with CCS.

3. Emissions implications of 'low-emission' hydrogen production

3.1. Emission intensity of hydrogen production

The emissions from hydrogen production vary widely depending on the feedstock and process used. Our analysis compares the emission intensity of hydrogen production processes using coal and gas with the direct emissions from the combustion of the fossil fuels (Fig. 1). These are calculated as kilograms of CO_2 equivalent emissions, which are released per unit of thermal energy (CO_2-e/GJ) or energy embedded in hydrogen with a lower heating value (LHV).[1]

Steam methane reforming (SMR) is currently the most common hydrogen production technology, accounting for roughly half of production globally. Black and brown coal are also commonly used as feedstocks in coal gasification (CG). In 2019 most CG facilities were located in China where CHN Energy produced 12% of global dedicated hydrogen production [15].

In both SMR and CG, hydrogen is separated from the carbon in the hydrocarbon feedstock, producing large amounts of CO_2 emissions, roughly 74 kg CO_2-e/GJ for SMR, 157 kg CO_2-e/GJ for CG with black coal and 170 kg CO_2-e/GJ for brown coal. The error bars in Fig. 1 reflect the large variation in emissions that occurs due to natural differences in the carbon content of fossil fuels, estimated from the default IPCC default emission factors [41]. Since we are not considering the embedded emissions in capital assets, hydrogen produced by electrolysis powered with zero-emission electricity will result in zero emissions in this analysis.

The total emissions intensities of the production of hydrogen made from both coal and gas without CCS are significantly higher than combusting the fossil-fuel feedstock. This is due to large energy losses in conversion. Typical efficiencies[2] used in the calculation are 78% for SMR [42] and 65% for CG [43].

As detailed in Section 2, fugitive emissions are rarely included in national and international strategies when assessing the emissions from fossil fuel based hydrogen. We use IPCC default emission factors for fugitive emissions associated with natural gas, and brown and black coal extraction [41] to calculate fugitive emission intensities for hydrogen production. The error bars represent the low and high values given by the IPCC to account for global variations. Our analysis shows that fugitive emissions from hydrogen production can be significant, accounting for a further 13 kg CO_2-e/GJ for hydrogen made from gas, and 26 kg CO_2-e/GJ from black coal. Brown coal is typically produced in open cut mines, which are associated with significantly lower fugitive emissions, accounting for less than 2 kg CO_2-e/GJ.

Both CG and SMR are highly optimised industrial processes, and CO_2 emissions have already been reduced as far as possible by minimising the additional energy needed for processing [44]. This means that any further reduction in process emissions will require CCS technologies to remove waste gases.

Hydrogen production from fossil fuels is considered a good candidate for CCS as the CO_2 is released from the process in a concentrated stream, which facilitates capture. However, applying carbon capture technologies to this 'process' gas waste stream only captures up to about two thirds of the total emissions. The rest are released by burning the feedstock as fuel to provide the energy to run the process, and are released in a dilute stream known as the 'flue' gases. Flue gases are more difficult, and expensive, to capture. Several different techniques can be used to capture CO_2 from either stream, all of which require additional energy and themselves result in additional emissions [44]. Additional energy is also required to compress the CO_2 for transport and storage, which is included in the calculation. However, the fuel required to transport and store the captured CO_2 is not included in this analysis as it is not well defined and depends on the distance to suitable geological storage facilities. This results in an underestimation of emissions.

Rates of carbon capture achieved in practice are rarely reported. In early 2021 there were only four commercial scale hydrogen facilities in the world operating with CCS, and another three in early development [45]. Of the four existing hydrogen facilities with CCS, three use the captured CO_2 for enhanced oil recovery. The only hydrogen facility that sequesters captured CO_2 is the Quest plant in Canada, which reported CCS rates of 80% for a high proportion of days during its first operating year [46]. Higher rates have been reported in relatively small-scale demonstration projects. The Tomakomai CCS demonstration project in Japan reported capture rates of 99% [47] and reached cumulative CO2 injection target of 300,000 tCO_2 into geological storage. The project has since ceased [48].

We set the carbon capture rates for 'low-emission' hydrogen production based on detailed techno-economic analyses provided by the IEA Greenhouse Gas R&D program for SMR [42], and the National Academy of Engineering [43] for CG. Both of these reports provided sufficient detail to analyse the effect of the variable carbon content of the feedstock on the overall emission intensity, which are illustrated by the error bars, and to include the contribution of fugitive emissions. We assume that all of the captured gas is sequestered underground in permanent geological storage.

The IEA analysis provides a techno-economic evaluation of different carbon capture technologies for a standalone merchant hydrogen SMR plant [13,14]. They assess a range of technologies for capturing CO_2 from the process gas stream with capture rates of 53% to 67%. When capture is from the flue gas stream there is a high capture rate of 90%. We extract two representative capture rates for our analysis given in Fig. 1. Capturing carbon from the process stream results in a capture rate of 56% and reduces the emission intensity to 36 kg CO_2-e/GJ on average. This requires additional energy to be applied to the process, resulting in a reduction of energy efficiency of the SMR plant of 4 percentage points, from 78% to 74%. Achieving higher capture rates of 90% by targeting the dilute stream in the flue gases reduces the emissions intensity to 8 kg CO_2-e/GJ on average, and requires significantly more energy input, reducing energy efficiency by an additional 5 percentage points, to 69%.

The National Academy of Engineering report on CG provides less detail about the CCS technology used, and assumes a capture rate of 90% [43]. In this case, 90% CCS reduced the emission intensity to 40 kg CO_2-e/GJ for black coal and reduces the energy efficiency of the process from 65% to 63%. Similar values are calculated for brown coal.

Of course, fugitive emissions associated with 'low-emission' hydrogen cannot be mitigated by CCS technology applied at the hydrogen processing plant. With 90% CCS, SMR has a total emission intensity of 21 kg CO_2-e/GJ when assuming the IPCC default fugitive emissions rate (1.70%). This increases to 28 kg CO_2-e/GJ when assuming higher levels of fugitive emissions (at a rate of 2.58% which is the high value provided by the IPCC to account for global variations in fugitive emissions). For black coal, the inclusion of fugitive emissions is even more significant, increasing the total emission intensity with 90% CCS rates to 65 kg CO_2-e/GJ (for the IPCC default rate of 1.21%) and this rises to 72 kg CO_2-e/GJ for higher levels of fugitive emissions (1.68%).

The rate of fugitive emissions due to fossil fuel extraction can vary widely, especially for natural gas [9,49]. Unconventional gas fields can have much higher emissions rates compared to the average [50,51], and the fugitive emissions rate is expected to grow [49,52,53]. In addition, a number of experts have advocated for using the 20 year global warming potential of 86 for methane, as the 100 year value of 28 underestimates global warming over shorter periods [10,54,55].

A comparison of the total emissions intensities for natural gas and hydrogen produced from natural gas is provided in the Appendix (Table A1). These were calculated for different methane leakage rates and use both 20 year and 100 year global warming potentials for methane. Following the work of Howarth and Jacobson, which assumed high fugitive emission rates (3.5%) and used the 20 year GWP of 86 for methane [10], the total emissions intensity of SMR hydrogen production with the best case CCS technology increases to nearly 100 kg CO_2-e/GJ. This is only 17% less emissions than burning natural gas directly with no CCS. For lower CCS capture rates of 56%, the emissions intensity is 120 kg CO_2-e/GJ, which is slightly higher than burning natural gas.

This analysis demonstrates that 'low-emission' hydrogen from fossil fuels will always have substantial emission intensities and that taking

[1] The lower heating value is the net heat content excluding the energy used to vaporise water. Using a LHV is consistent with the method used by the IEA [15].

[2] Efiicency is defined as energy embedded in the hydrogen produced divided by the energy embedded in the feedstock and any additional fuel used.

Table 2
Estimated global emissions from fossil fuel based hydrogen production assuming two future demand levels. Calculated for different fossil fuel feedstocks, with and without carbon capture and storage (CCS). The two demand levels used (187 Mt/yr and 696 Mt/yr) correspond to the BNEF low and high hydrogen demand senarios [16].

Production from:	2050 emissions projected with fossil fuels at 100% of total production (MtCO2e)		2050 emissions projected with fossil fuels at 40% of total production (MtCO2e)	
	BNEF Moderate (187 Mt/yr)	BNEF High (696 Mt/yr)	BNEF Moderate (187 Mt/yr)	BNEF High (696 Mt/yr)
CG (Black coal)	4876	18,150	1951	7260
CG (Black coal + 90% CCS)	1743	6487	697	2595
CG (Brown coal)	4578	17,040	1831	6816
CG (Brown coal + 90% CCS)	1150	4281	460	1712
SMR	2319	8632	928	3453
SMR with 56% CCS	1340	4988	536	1995
SMR with 90% CCS	561	2088	224	835

into account fugitive emissions is critical.

3.2. Assessing 'low-carbon' hydrogen using the CertifHy benchmark

This section compares the emission levels discussed in section 3.1 to a carbon intensity threshold that has been set by a recently developed certification scheme. In addition to the interaction between national strategies and plans, the development of certification is relevant to choices between technologies [56]. The European CertifHy Guarantee of Origin scheme accounts for the origin of hydrogen and whether it was produced using renewable energy or non-renewable low emission energy sources, such as nuclear, or fossil fuels with CCS. CertifHy also defines an emission intensity for 'low-carbon' hydrogen as a 60% reduction in emission intensity below a standard SMR production process [57,58]. Otherwise, the hydrogen would be considered to be 'grey' hydrogen [59]. This emission intensity threshold may be adopted widely as CertifHy appears to be emerging as the standard to follow in the EU with The Netherlands, France and the United Kingdom indicating that they will adopt it [56].

Only hydrogen produced from gas with a high capture rate of 90% is below the CertifHy threshold (Fig. 1). This does not hold with a fugitive emission rate above 3% (Table A1 in the appendix). While these high capture rates are assumed in many national strategies and major reports, they have not yet been achieved in a large scale commercial plant and have only recently been achieved in the Tomakomai CCS demonstration project, which required very high expenditure (which was $127/tCO_2$, as discussed in section 4) [47]. Fugitive emission rates of over 3% have been observed in USA gas fields [50].

3.3. Implications for global emissions

To put the emission intensity estimates from Fig. 1 in perspective, we illustrate the emissions that could occur under some demand scenarios (Table 2). Bloomberg NEF projects that with comprehensive government policy support, consistent with successfully limiting global warming to 1.5C above pre-industrial levels, demand for low emission hydrogen could be as high as 696 Mt/year, whereas with piecemeal policy approaches that projection is reduced to 187 Mt/year [16]. The IEA estimates that by 2070, 40 per cent of total hydrogen demand could be produced from fossil fuels with CCS [60].

Combining these projections with our emission intensities means that if SMR with CCS at a capture rate of 90% were to occupy 40% of total production in BNEF's strong scenario, the amount of GHG emissions generated annually (835 MtCO2e) would be equal to 2.5% of 2019 energy related CO2 emissions [15,61]. With capture rates below 90 per cent, the projection would rise. In the context of a world seeking net carbon neutrality, this would represent a sizeable offset requirement.

4. Determinants of the production cost of hydrogen

4.1. Costs of producing hydrogen from fossil fuels

The production cost of hydrogen from fossil fuels is heavily determined by two factors: capital expenditure and the cost of the feedstock. CG has higher capital costs ($2670/kW) than SMR ($910/kW), but lower fuel costs for coal mean that these options will have a similar production cost in certain scenarios [16]. For CG processes, capital costs account for around 50% of production costs and fuel is between 15% and 20% depending on the cost of coal. For SMR processes, the IEA estimated that fuel costs are likely to be between 45% and 75% of hydrogen

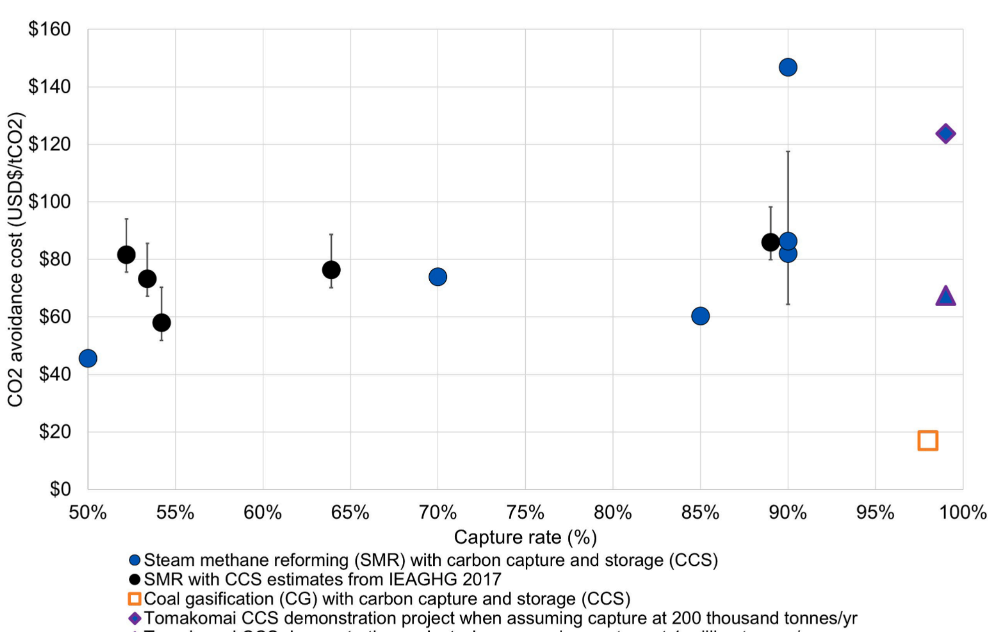

Fig. 2. CO_2 avoidance cost by capture rate. Data for SMR production are taken from a range of studies that report a CO_2 avoidance cost (blue circles), with details provided in the appendix in tables A3 and A5. These are compared to estimated CO_2 avoidance costs for the Tomakomai CCS demonstration project [47] (purple diamond and triangle). Data from the IEAGHG study [13,14], which provides the most comprehensive techno-economic comparison between SMR technologies with different capture rates, are shown as black circles. Data for coal gasification (orange rectangle) is taken from [87]. The error bars show the impact of doubling or halving the transport and storage costs for those studies that report them.

Table 3
Ordinary Least Squares (OLS) regression estimates for the production cost of hydrogen (PC) using data sourced from an IEA report [15], which were used to specify the six cost curves in Fig. 3. Standard errors are given in parentheses. Statistical significance as follows: *** $p < 0.01$, ** $p < 0.05$, * $p < 0.1$.

Variables	Coefficients
Electricity cost (EC)	0.475***
	(0.00)
Ratio of capital cost (CC) and capacity factor (CF)	0.037***
	(0.00)
Constant	0.174***
	(0.01)
R-squared	0.999
Number of observations	24

production costs. The IEA estimates that adding CCS to CG would increase capital and fuel costs by 5% and increase operation costs by 130%. Adding CCS to an SMR plant will also increase costs, which the IEA has estimated to be, on average, a 50% increase in capital costs, an additional 10% for fuel costs and a doubling of operational costs for CO_2 transport and storage [15].

4.2. CO_2 avoidance cost

The CO_2 avoidance cost is the difference between producing hydrogen with and without emissions capture. It is equivalent to the carbon price that would need to be applied for these two options to have the same production cost. There are multiple methods for calculating the CO_2 avoidance cost, but the most valid approach is to compare a given facility with a fixed level of production with and without CCS. This requires detailed techno-economic modelling as in the reports used for the analysis in section 3 [13,43]. As well as the costs of CO_2 capture, it should include costs of transport and storage at suitable geological formations [8]. Many studies do not include transport and storage costs, which will differ based on location and whether storage is onshore or offshore [62]. Some studies do not use an exhaustive approach and only account for the costs of CO_2 capture without CO_2 transport and storage, which is consistent with a 'cost of CO_2 captured' [7,8]. Assessments also commonly do not account for the costs of long-term storage and monitoring to ensure that the carbon captured remains underground. Accordingly, the actual costs of carbon avoided are likely to be higher than existing studies suggest.

CO_2 avoidance costs differ greatly and depend on the capture rate due to the process used and additional energy needs (Fig. 2). The median estimates from the range of studies[3] included in this analysis are $17/$tCO_2$ for CG with CCS and $76/$tCO_2$ for SMR with CCS. While there is large variation in capture costs, it is clear that higher capture rates will be more expensive. Five out of six estimates with capture rates equal to or below 70% were under $80/$tCO_2$. For capture rates over 85%, five out of seven estimates are over $80/$tCO_2$ and two of these estimates are above $120/$tCO_2$.

The IEAGHG study provides the most comprehensive techno-economic comparison between SMR technologies with different capture rates [13,14]. Assuming relatively low transport and storage costs of $11/$tCO_2$, this work found that CCS at a 56% capture rate increases the cost of hydrogen by 18%, while 90% capture rates increase the cost by 45%.

At the recent Tomakomai CCS demonstration project in Japan, CO_2 avoidance costs for a high capture rate of 99% were $127/$tCO_2$. This cost was for 200,000 tons of CO_2 captured between April 2016 and November 2019. Increasing the size of that demonstration project by a factor of five would decrease CO_2 avoidance costs by approximately 50% (from $124/$tCO_2$ to $67/$tCO_2$). Most of this projected cost reduction was attributed to reductions in the relative magnitude of capital costs and operation costs of the injection wells and storage. CO_2 transportation costs were not included in this analysis [47]. This means that the CO_2 avoidance cost below $80/$tCO_2$ for a capture rate of 99% quoted in that study has not been demonstrated but was extrapolated using assumptions.

The estimates for transport and storage are particularly uncertain as very few CCS plants sequester the gases in long term underground storage and the magnitude of these costs will be highly site-dependent. The studies that we reviewed have transport and storage costs as low as $5/$tCO_2$ and as high as $29/$tCO_2$ (Tables A3 and A5 in the appendix). A recent study provided ranges for transport and storage costs when the storage site was assumed to be onshore ($3–18/$tCO_2$) or offshore ($5–50/tCO_2) [62]. The error bars in Fig. 2 show the impact of doubling or halving the transport and storage costs for those studies that report them.

4.3. Determinants of the production cost of hydrogen using electrolysis and renewables

4.3.1. Costs of producing hydrogen using renewables

The largest factor determining the cost of producing hydrogen using electrolysis is the cost of electricity [63,64]. With electricity costs between $61/MWh and $69/MWh, the magnitude of electricity expenditure has been estimated at 65–80% of total hydrogen production costs [65,66]. The other notable cost components are the capital cost of electrolysers and the capacity utilisation of electrolysers. Other costs, such as labour, land and water, are a minor determinant of the production cost of hydrogen by electrolysis.

Recent decreases in the cost of electricity generation from solar photovoltaic (PV) and wind have lowered the cost of producing hydrogen using electrolysis. Capital costs for solar PV installations fell by 79% from 2010 to 2019 and by 24% for onshore wind generators [67]. This results in lower average costs of generating electricity over the lifetime of assets. The levelised cost of electricity (LCOE) for solar PV installations was $35/MWh in 2020 and has been projected to decrease to $20/MWh by 2030 [67,68]. For wind, the equivalent numbers are $33/MWh and $31/MWh [67,69][4].

Electrolyser manufacturing costs are expected to fall substantially as deployment of electrolysers increases [16]. The capital cost of alkaline electrolysers were between $500–1400/kW in 2019 and projected to fall to $400–850/kW by 2030. Polymer electrolyte membrane (PEM) electrolysers were between $1100–1800/kW in 2019 and projected to be between $650–1500/kW by 2030 [70]. However, lower capital costs have been reported. The electrolyser producing company Nel has reported an alkaline electrolyser cost of $700/kW for 2015 and a projection of a little over $490/kW for the near-term future [71,72].

4.3.2. Specification of the production cost of hydrogen from electrolysis

To assess the cost of producing hydrogen via electrolysis a multivariate specification is needed to account for the three main determining factors. We developed a simple equation that accurately captures the IEA estimates for hydrogen production costs using electrolysis [15]. The equation that estimates a hydrogen production cost (PC) for a given electricity cost (EC), capital cost (CC) and operating capacity factor (CF)[5] is:

$$PC = \beta_0 + \beta_1 EC + \beta_2 \frac{CC}{CF} \tag{1}$$

where β_0 is an intercept and β_1, β_2 are parameters that define the impact of electricity costs and the ratio of capital cost and capacity factor. To specify equation (1) we used 24 data points from the IEA hydrogen cost

[3] Note that we have only included studies published in the last ten years.

[4] The supplementary material includes a review of the levelised cost of electricity (LCOE) for solar PV and wind.

[5] The operating capacity factor is important for applications with standalone intermittent renewables as it impacts the number of hours an electrolyser runs. The IEA assumes that running an electrolyser at full capacity has an OCF of 90%. We lower the OCF to 45% and 30% for intermittent renewable scenarios.

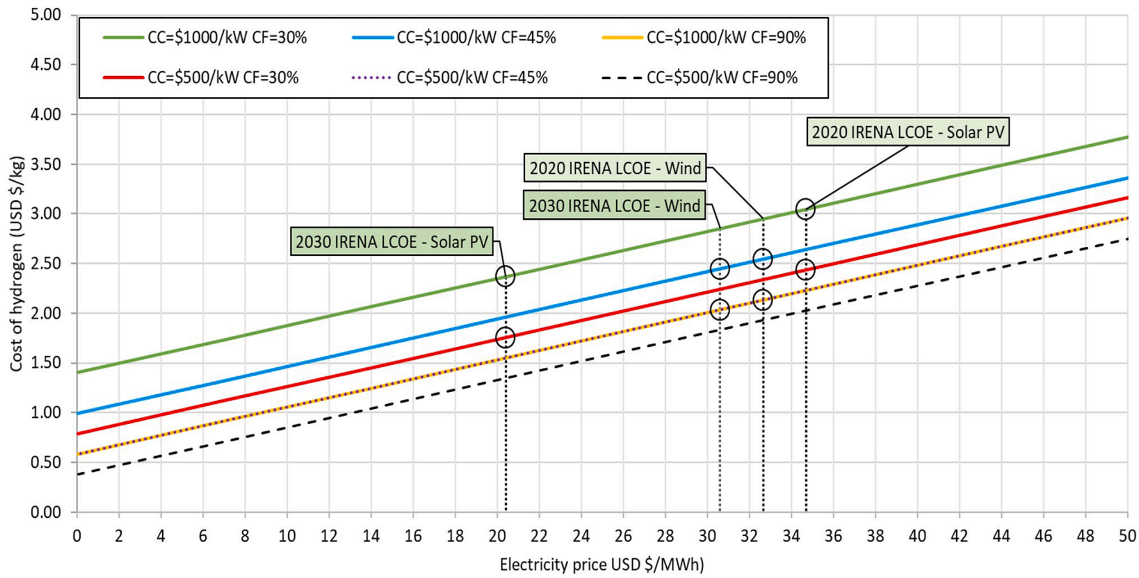

Fig. 3. Production cost of hydrogen via electrolysis as a function of the cost of electricity, which were calculated using the regression results shown in Table 3. Cost curves are shown for two levels of electrolyser capital costs, CC = $1000/kW and $500/kW, and three levels of capacity factors, CF = 90% (assuming grid connection), 45% (assuming stand-alone wind power), and 30% (assuming stand-alone solar-power).

relationship to estimate an Ordinary Least Squares regression. The high level of model fit (i.e. R-squared statistic) confirms that the other components of cost, such as labour, land and water, can be accurately estimated using a constant (Table 3).

We use these regression estimates to specify six cost curves for two levels of electrolyser capital costs (CC), i.e. $1000/kW and $500/kW, and three levels of capacity factors (CF), i.e. 90%, 45%, and 30% (Fig. 3). The higher capital cost point proxies the costs of Alkaline electrolysers today and possible cost levels of PEM electrolysers in the near future. The lower capital cost point proxies costs that might be able to be achieved over the next decade. Note that considerable capital cost reductions could occur as a learning rate of 18% has been estimated for electrolysers [73–75].

The operating capacity factor for electrolysers and associated emissions will depend on the energy sources. We focus on examples where an electrolyser is run from stand-alone renewable energy sources. A grid connection will generally mean some use of fossil fuel based electricity and emissions associated with the production of hydrogen. We focus on the case of using renewable electricity as a feedstock and assume that an electrolyser run off a wind farm could operate at capacity factors close to 45%, and a standalone solar farm at around 30%. We developed production costs of hydrogen using the LCOEs for solar PV and wind in 2020 and 2030 sourced from IRENA and discussed in section 4.3.1. These hydrogen production costs are $2.43–3.05/kg and $1.76–2.37/kg using the solar LCOEs for 2020 and 2030. The equivalent estimates are $2.13–2.54/kg and $2.04–2.44/kg for wind (Fig. 3).

We have used low LCOE estimates and higher capacity utilization factors, as it is likely that these will be more relevant in practice as hydrogen production would be run at the lowest cost renewable energy generation sites. We also emphasize the uncertainty regarding future cost estimates, and the possibility of large and rapid cost reductions as the industry scales up.

5. Comparison of costs across hydrogen technologies

We complete the analysis by comparing estimates from 16 studies (listed in the appendix[6]) for the different hydrogen production technologies considered in section 3: SMR and CG with and without CCS. We also include the selected estimates for renewable energy powered electrolysis from section 4.3.2 (Fig. 3). These estimates are for the whole production process up until the plant gate and do not include the storage or transport of hydrogen.

Currently, producing hydrogen with fossil fuels costs less than producing it with renewable energy powered electrolysis (Fig. 4). The additional cost of CCS is significant and increases the median (or central) estimates from $1.66–1.84/kg without CCS to $2.09–2.23/kg with CCS. These median estimates increase by a considerable amount when a carbon penalty on remaining emissions of $50/tCO2e is assumed (approximately the market price of EU emissions trading at the time of writing)[7]. This increases the median estimates for fossil fuels with CCS from $2.09–2.23/kg to $2.24–2.70/kg. In comparison, the median estimate for renewables driven electrolysis could decrease from $3.64/kg for the present day to $1.85/kg when capital and/or electricity costs are lower. The assumptions used differs by study and these are provided in the appendix. They include estimates that use an LCOE as low as $10/MWh and the lowest level of capital costs is $200/kW.

A range of target prices have been set in various strategies and $2/kg is a common benchmark for cost-competitive hydrogen. It has been set as a target by the US Department of Energy for the levelised cost of hydrogen at the plant gate [76]. A comparable figure (20 yen/Nm^3) was also included in the Japanese Hydrogen Strategy as a target for the landed cost of imports of hydrogen [18].[8] Australia has a $2/kg (AUD) production cost target for 'clean' hydrogen, which is equivalent to $1.4/kg (USD) [77].

While the cost of producing hydrogen via electrolysis is expected to fall, fossil fuel and carbon capture options are mature technologies. Likewise, it is unlikely that there will be significant reductions in the cost of carbon transport and storage as improvements from economies of scale will be limited. The inclusion of realistic CO_2 transport, storage and monitoring costs would lead to higher costs than currently projected.

From our analysis, we can extract an implied carbon price that would be required to make low emission fossil-fuel technologies (i.e. SMR and CG with 90% CCS) break even with current fossil-fuel hydrogen costs.

[6] The appendix contains the data points used to produce Figure 4 and has a description of the technology/scenario that was used to estimate a production cost of hydrogen. Figure 4 contains 97 data points from a wide range of studies.

[7] This was €44.33 on April 16 2021, which equates to $53 USD.

[8] Note that this Japanese target would need to include the cost of transport and storage to be achieved.

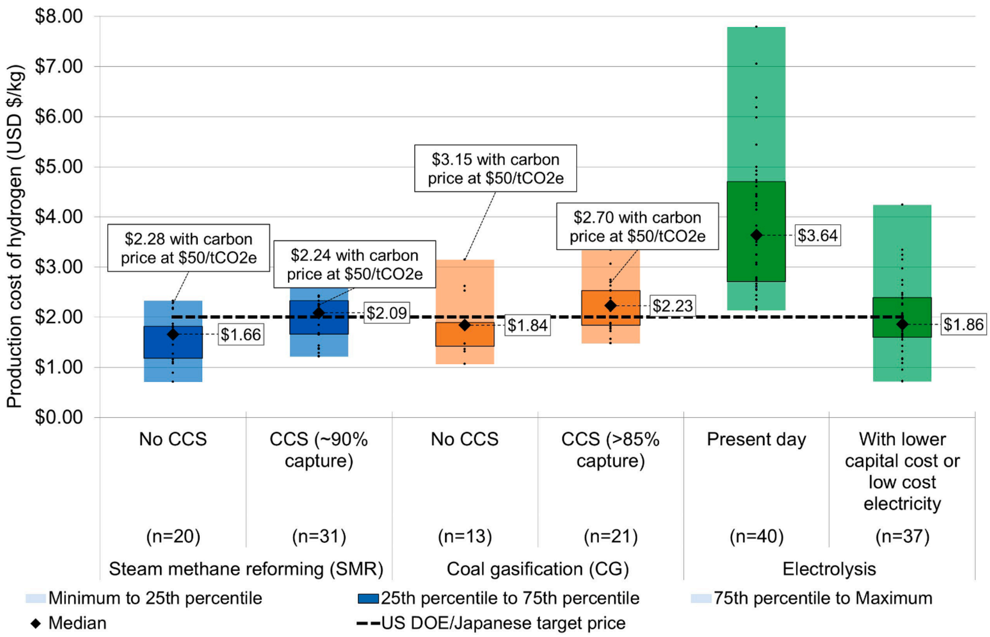

Fig. 4. Estimated production cost of hydrogen for different production technologies, which were collated using 97 estimates from 16 studies (black dots). References and data are provided in the appendix in Tables A2-A7. The median cost estimate for each technology type is given (black dimond), as well as the full data ranges. The 25th-75th percentile range is shown as a darker coloured box. Results are compared to the USA and Japanese target hydrogen price (dashed line). The impacts of a carbon price of $50/tCO$_2$e are also given and were computed using the median cost estimate and the total emission intensities shown in Figure 1.

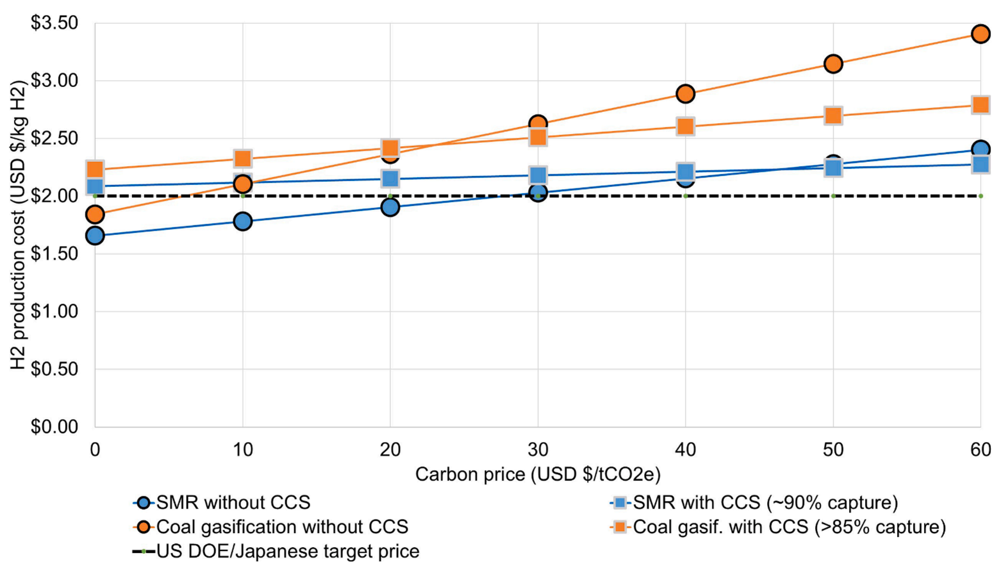

Fig. 5. Hydrogen production costs as a function of carbon pricing for steam methane reforming (SMR) and coal gasification (CG). Costs are shown with (circles) and without (squares) high levels of carbon capture and storage. These costs were computed using the median costs estimates presented in Fig. 4 and the total emission intensities shown in Fig. 1. Results are compared to the USA and Japanese target hydrogen price (dashed line).

Using the median estimates from Fig. 4, a carbon price of $22/tCO$_2$e (CG) and $46/tCO$_2$e (SMR) would be required to make hydrogen production from fossil fuels with CCS achieve cost parity with the non-CCS option. This occurs at a production cost of $2.23/kg (SMR) and $2.43/kg (CG) (Fig. 5). This is due to a high carbon abatement cost and reflects the costliness of CCS as an option to decarbonise hydrogen production. Achieving capture rates above 85% is expensive, the residual emissions are notable, and CCS has no impact on fugitive emissions, which are included in this analysis. So, it only takes a moderate increase in costs, either a carbon price or revised costs of transport, storage and monitoring, to shift the median CCS estimates away from the example target price of $2/kg. These increases in cost also make these technological options less favourable compared to electrolysis with lower capital cost or low-cost electricity.

6. Conclusions

A number of government strategies foresee ‘low-emission’ hydrogen production from fossil fuels with CCS as a technology that could be part of future hydrogen industries. We find that these ‘low-carbon’ production methods create significant greenhouse gas (GHG) emissions when realistic carbon capture rates and fugitive emissions from feedstock extraction are taken into account. The extent of the emissions is often downplayed or ignored in governments’ public statements about future hydrogen supply chains, with many treating ’low-emission’ and ’zero-emission’ production as functionally equivalent or interchangeable. The high rates of carbon capture typically posited in government strategies are likely to be both difficult to achieve in practice and costly. CCS is an expensive option for decarbonising hydrogen production. Our analysis shows that carbon prices of $22–46/tCO$_2$e would be required to make hydrogen from fossil fuels with CCS competitive with hydrogen produced from fossil fuels without CCS. Carbon avoidance costs for high capture rates tend to be above $80/$tCO_2$. In contrast, the cost of producing zero-carbon hydrogen from electrolysis could fall in the foreseeable future, and be cost-competitive with fossil fuel options. This means that the economic case for fossil fuels with CCS is generally limited.

Hydrogen can help achieve decarbonisation of global energy systems, however the use of coal or natural gas would come with significant remaining emissions even if relatively high carbon capture rates were achieved. Using emission intensities that include fugitive emissions means that if SMR with CCS at a capture rate of 90% were to occupy 40% of total hydrogen production, the amount of GHG emissions generated annually would equal 2.5% of 2019 energy related CO_2 emissions. Hydrogen produced from fossil fuels without CCS would result in much higher emissions compared to unmitigated combustion of fossil fuels. Setting up new fossil fuel-based hydrogen supply chains using fossil fuels without CCS would be detrimental.

As CCS and fossil fuel-based facilities have long lifetimes, early investment in fossil fuel-based hydrogen production creates a risk of lock-in. Tightening carbon constraints combined with decreases in the cost of hydrogen from electrolysis will raise the possibility that natural gas- and coal-based hydrogen production assets could become stranded. Meanwhile, many national hydrogen strategies define both fossil fuel with CCS and renewable based options as 'clean' and/or 'low-emission'. The current framing of these options suggests that there is a risk of government support for an option incompatible with stated objectives of energy system decarbonisation and net-zero emissions outcomes. For governments that are looking to help create a hydrogen economy that will stand the test of time, supporting projects aimed at establishing supply chains and exporting electrolysis-based hydrogen from countries with high quality renewable energy resources is less risky and will do more for decarbonisation and net-zero emissions outcomes.

CRediT authorship contribution statement

Thomas Longden: Conceptualization, Methodology, Formal analysis, Writing – original draft, Visualization. **Fiona J. Beck:** Conceptualization, Methodology, Formal analysis, Writing – review & editing. **Frank Jotzo:** Conceptualization, Methodology, Writing – review & editing. **Richard Andrews:** Investigation, Formal analysis, Writing – review & editing. **Mousami Prasad:** Investigation, Data curation.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix A

Tables A1–A7

Table A1
Total emissions intensities (fugitive, process and direct) for natural gas compared to hydrogen produced from natural gas. Calculated for different methane leakage rates, and using 20 year and 100 year global warming potentials (GWP) for methane

GWP and methane leakage rate (%) used	Natural gas	Hydrogen from gas	Hydrogen from gas with 56% CCS	Hydrogen from gas with 90% CCS
100 year GWP of 28				
0.9% (IPCC low)	61.25	80.19	43.60	15.60
1.7% (IPCC default)	65.92	87.06	49.47	22.35
3.5% (Howarth & Jacobson) [10]	76.42	100.88	63.73	37.54
20 year GWP of 86				
0.9% (IPCC low)	72.13	95.23	59.33	31.33
1.7% (IPCC default)	86.46	114.11	77.37	52.06
3.5% (Howarth & Jacobson) [10]	118.71	156.57	121.18	98.72

Table A2
Levelised cost of hydrogen (USD $/kg) – Steam methane reforming.

Source	Description	LCOH (USD $/kg)
NREL 2013 [78]	Centralised hydrogen production facility with a design capacity of 379 tH2 per day with natural gas carried by pipeline.	2.19
Hosseini et al. 2016 [79]	Natural gas reforming without CO_2 capture.	1.11
Salkuyeh et al. 2017 [80]	Steam methane reforming producing 446 tH2 per day.	1.15
IEAGHG 2017 [14]	Hydrogen plant without CCS (base case).	1.68
Keipi et al. 2018 [81]	Steam methane reforming producing 209 tH2 per day.	2.33
IEA 2019 [15]	Natural Gas without CCUS (adjusted to have no carbon price) sourced from Figure 16.	1.87
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for Australia	1.45
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for Chile	1.64
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for China	1.69
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for Europe	1.73
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for India	1.82
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for Japan	2.16
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for Middle east	0.89
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for North Africa	1.27
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for United States	1.08
IEA 2020 [37]	Hydrogen cost via SMR – lowest 2019 value from Figure 2.14.	0.71
	Hydrogen cost via SMR – highest 2019 value from Figure 2.14.	1.62
Roussanaly et al 2020 [82]	Hydrogen production through natural gas reforming without CCS with plant capacity at 450 tH2 per day. Assumed to be located on the Northern Norway shore with a carbon intensity of 1.37 MtCO2/year without CO2 capture.	1.79

Table A3
Levelised cost of hydrogen (USD $/kg) – Steam methane reforming with carbon capture.

Source	Description	LCOH (USD/kg)	CO2 Avoided (%)	Carbon avoidance cost (USD/tCO2)	Includes T&S cost (USD/tCO2)
Salkuyeh et al. 2017 [80]	SMR with CCS.	2.33	90%	146.9	
IEAGHG 2017 [14]	CO2 capture from syngas using MDEA (case 1A).	1.98	54%	58.0	12.3
	CO2 capture from syngas using MDEA with H2-rich fuel firing burners (case 1B).	2.15	64%	76.4	12.3
	CO2 capture from PSA tail gas using MDEA (case 2A).	2.09	52%	81.7	12.3
	CO2 capture from PSA tail gas using Cryogenic and Membrane Technology (case 2B).	2.06	53%	73.3	12.3
	CO2 capture from flue gas using MEA (case 3).	2.43	89%	86.0	12.3
CE Delft 2018 [83]	SMR without capture via flue gas.	1.98	50%	45.6	
	SMR without capture via flue gas.	2.15	70%	73.9	
	SMR with capture via flue gas or H2 used as fuel.	2.26	85%	60.4	
	SMR with capture via flue gas or H2 used as fuel.	2.43	90%	86.2	
CSIRO 2018 [84]	Best case for SMR with CCS.	1.66	92%		5.4
	Base case for SMR with CCS.	2.03	92%		29.3
	Best case for SMR with CCS.	1.38	92%		5.1
	Base case for SMR with CCS.	1.68	92%		29.3
IEA 2019 [15]	Natural Gas with CCUS (adjusted to have no carbon price) sourced from Figure 16.	2.41	89%		20.6
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for Australia.	1.85	89%		20.6
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for Chile.	2.07	89%		20.6
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for China.	2.11	89%		20.6
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for Europe.	2.22	89%		20.6
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for India.	2.22	89%		20.6
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for Japan.	2.67	89%		20.6
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for Middle east.	1.29	89%		20.6
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for North Africa.	1.65	89%		20.6
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for United States.	1.43	89%		20.6
IEA 2020 [37]	Hydrogen cost via SMR – lowest 2050 value from Figure 2.14.	1.21	95%		20.2
	Hydrogen cost via SMR – highest 2050 value from Figure 2.14.	2.13	95%		20.2
BNEF 2020 [16]	Natural gas with CCS – highest 2019 value.	2.93	90%		
	Natural gas with CCS – lowest 2019 value.	1.37	90%		
	Natural gas with CCS – highest 2030 value.	2.90	90%		
	Natural gas with CCS – lowest 2030 value.	1.36	90%		
	Natural gas with CCS – highest 2050 value.	2.79	90%		
	Natural gas with CCS – lowest 2050 value.	1.22	90%		
Roussanaly et al 2020 [82]	Hydrogen production through natural gas reforming without CCS with plant capacity at 450 tH2 per day. Assumed to be located on the Northern Norway shore with a well injection rate of 0.8 MtCO2 per year per well.	2.66	90%	82.1	35.5

Table A4
Levelised cost of hydrogen (USD $/kg) – Coal gasification.

Source	Description	LCOH (USD/kg)
IEAGHG 2014 [87]	General Electric, Radiant Syngas Cooler.	2.62
IEA 2019 [15]	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for Australia.	1.84
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for China.	1.06
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for Europe.	1.79
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for India.	1.37
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for Middle East.	1.47
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for North Africa.	1.32
	Natural Gas without CCUS (adjusted to have no carbon price) using assumptions for United States.	1.85
	Coal without CCUS (adjusted to have no carbon price) sourced from Figure 16.	1.87
IEA 2020 [37]	Hydrogen cost via coal gasifier – lowest 2019 value from Figure 2.14.	1.92
	Hydrogen cost via coal gasifier – highest 2019 value from Figure 2.14.	2.53

Table A5
Levelised cost of hydrogen (USD $/kg) – Coal gasification with carbon capture.

Source	Description	LCOH (USD/kg)	CO2 Avoided (%)	Carbon avoidance cost (USD/tCO2)	Includes T&S cost (USD/tCO2)
IEAGHG 2014 [87]	General Electric, Radiant Syngas Cooler with additional MDEA solvent scrubbing to achieve near zero CO2 emission.	2.74	98%	16.93	12.70
CSIRO 2018 [84]	Hydrogen cost for coal gasifier with CCS – base case lower range value for black coal.	1.88	85%		5.13
	Hydrogen cost for coal gasifier with CCS – base case upper range value for black coal.	2.30	85%		29.29
	Hydrogen cost for coal gasifier with CCS – best case lower range value for black coal.	1.48	85%		5.13
	Hydrogen cost for coal gasifier with CCS – best case upper range value for black coal.	1.81	85%		29.29
	Hydrogen cost for coal gasifier with CCS – best case lower range value for brown coal.	1.57	85%		5.13
	Hydrogen cost for coal gasifier with CCS – best case upper range value for brown coal.	2.02	85%		29.29
IEA 2019 [15]	Natural Gas with CCUS (adjusted to have no carbon price) using assumptions for Australia	2.30	90%		20.62
	Natural Gas with CCUS (adjusted to have no carbon price) using assumptions for China	1.48	90%		20.62
	Natural Gas with CCUS (adjusted to have no carbon price) using assumptions for Europe	2.23	90%		20.62
	Natural Gas with CCUS (adjusted to have no carbon price) using assumptions for India	1.72	90%		20.62
	Natural Gas with CCUS (adjusted to have no carbon price) using assumptions for Middle East	1.87	90%		20.62
	Natural Gas with CCUS (adjusted to have no carbon price) using assumptions for North Africa	1.77	90%		20.62
	Natural Gas with CCUS (adjusted to have no carbon price) using assumptions for United States	2.32	90%		20.62
	Coal with CCUS (adjusted to have no carbon price) sourced from Figure 16.	2.38	90%		20.62
IEA 2020 [37]	Hydrogen cost via coal gasifier and CCS – lowest 2050 value from Figure 2.14.	2.13	90%		20.24
	Hydrogen cost via coal gasifier and CCS – highest 2050 value from Figure 2.14.	2.63	90%		20.24
BNEF 2020 [16]	Coal with CCS – highest 2019 value.	3.37	90%		
	Coal with CCS – lowest 2019 value.	2.54	90%		
	Coal with CCS – highest 2030 value.	3.35	90%		
	Coal with CCS – lowest 2030 value.	2.53	90%		
	Coal with CCS – highest 2050 value.	3.06	90%		
	Coal with CCS – lowest 2050 value.	2.23	90%		

Table A6
Levelised cost of hydrogen (USD $/kg) – Electrolyser (present day).

Source	Description	LCOH (USD/kg)
CSIRO 2018 [84]	PEM – base case lower range value with a capital cost of $2497/kW and an LCOE of $43/MWh.	4.45
	PEM – base case upper range value with a capital cost of $2497/kW and an LCOE of $43/MWh.	5.44
	AE – base case lower range value with a capital cost of $962/kW and an LCOE of $43/MWh.	3.50
	AE – base case upper range value with a capital cost of $962/kW and an LCOE of $43/MWh.	4.28
NREL 2019 [85]	PEM with a capital cost of $841/kW and an LCOE of $66/MWh.	4.92
	PEM with a capital cost of $841/kW and an LCOE of $20/MWh.	4.74
	PEM with a capital cost of $841/kW and an LCOE of $10/MWh.	4.23
IEA 2019 [15]	Electrolysis with grid based electricity at $98/MWh (Fig. 16).	5.00
	Electrolysis, upper value from Fig. 19 with assumptions for Australia including capital cost at $700/kW and variable electricity at $31/MWh.	3.82
	Electrolysis, upper value from Fig. 19 with assumptions for Chile including capital cost at $700/kW and variable electricity at $23/MWh.	3.09
	Electrolysis, upper value from Fig. 19 with assumptions for China including capital cost at $700/kW and variable electricity at $18/MWh.	2.35
	Electrolysis, upper value from Fig. 19 with assumptions for Europe including capital cost at $700/kW and variable electricity at $47/MWh.	4.14
	Electrolysis, upper value from Fig. 19 with assumptions for India including capital cost at $700/kW and variable electricity at $19/MWh.	2.76
	Electrolysis, upper value from Fig. 19 with assumptions for Japan including capital cost at $700/kW and variable electricity at $63/MWh.	6.38
	Electrolysis, upper value from Fig. 19 with assumptions for Middle East including capital cost at $700/kW and variable electricity at $25/MWh.	4.41

(continued on next page)

Table A6 (*continued*)

Source	Description	LCOH (USD/kg)
	Electrolysis, upper value from Fig. 19 with assumptions for North Africa including capital cost at $700/kW and variable electricity at $23/MWh.	3.25
	Electrolysis, upper value from Fig. 19 with assumptions for United States including capital cost at $700/kW and variable electricity at $31/MWh.	3.63
IRENA 2019 [4]	Electrolysis with capital cost at $840/kW and electricity at $40/MWh.	3.64
	Electrolysis with capital cost at $840/kW and electricity at $20/MWh.	2.59
	Electrolysis with capital cost at $840/kW and electricity at $85/MWh.	6.19
	Electrolysis with capital cost at $840/kW and electricity at $55/MWh.	4.69
	Electrolysis with capital cost at $840/kW, capacity factor at 26% and electricity at $85/MWh.	7.06
	Electrolysis with capital cost at $840/kW, capacity factor at 48% and electricity at $55/MWh.	4.42
	Electrolysis with capital cost at $840/kW, capacity factor at 26% and electricity at $17.50/MWh.	3.44
	Electrolysis with capital cost at $840/kW, capacity factor at 48% and electricity at $23/MWh.	2.73
IRENA 2020 [38]	High point of current day electrolysis estimate.	5.98
	Mid. point of current day electrolysis estimate.	4.84
	Low point of current day electrolysis estimate.	2.67
IEA 2020 [37]	Hydrogen cost via electrolysis – highest 2019 value from Figure 2.14.	7.79
	Hydrogen cost via electrolysis – lowest 2019 value from Figure 2.14.	3.24
BNEF 2020 [16]	Renewable H2 – highest 2019 value.	4.61
	Renewable H2 – lowest 2019 value.	2.55
Estimates from section 4.3.2 using 2020 LCOE data from IRENA 2020 (shown in Fig. 3)	Electrolysis with capital cost at $1000/kW, capacity factor at 30% and electricity at $35/MWh.	3.05
	Electrolysis with capital cost at $1000/kW, capacity factor at 45% and electricity at $33/MWh.	2.54
	Electrolysis with capital cost at $500/kW, capacity factor at 30% and electricity at $35/MWh.	2.43
	Electrolysis with capital cost at $500/kW, capacity factor at 45% and electricity at $33/MWh.	2.13
Estimates from section 4.3.2 using 2020 LCOE data from GenCost 2020 [86]	Electrolysis with capital cost at $1000/kW, capacity factor at 30% and electricity at $29/MWh.	2.79
	Electrolysis with capital cost at $500/kW, capacity factor at 30% and electricity at $29/MWh.	2.18
	Electrolysis with capital cost at $1000/kW, capacity factor at 45% and electricity at $34/MWh.	2.62
	Electrolysis with capital cost at $500/kW, capacity factor at 45% and electricity at $34/MWh.	2.21

Table A7
Levelised cost of hydrogen (USD $/kg) – Electrolyser (with lower capital cost or low cost electricity).

Source	Description	LCOH (USD/kg)
CSIRO 2018 [84]	PEM – base case lower range value with a capital cost of $691/kW and an LCOE of $29/MWh.	1.68
	PEM – base case upper range value with a capital cost of $691/kW and an LCOE of $29/MWh.	2.04
	AE – base case lower range value with a capital cost of $723/kW and an LCOE of $29/MWh.	1.86
	AE – base case upper range value with a capital cost of $723/kW and an LCOE of $29/MWh.	2.27
NREL 2019 [85]	PEM with a capital cost of $462/kW and an LCOE of $20/MWh.	3.15
	PEM with a capital cost of $462/kW and an LCOE of $10/MWh.	2.64
IEA 2019 [15]	Electrolysis with renewable electricity at $40/MWh (Fig. 16).	2.97
	Electrolysis, upper value from Fig. 19 with assumptions for Australia including capital cost at $450/kW and variable electricity at $31/MWh.	2.39
	Electrolysis, upper value from Fig. 19 with assumptions for Chile including capital cost at $450/kW and variable electricity at $23/MWh.	1.62
	Electrolysis, upper value from Fig. 19 with assumptions for China including capital cost at $450/kW and variable electricity at $18/MWh.	1.62
	Electrolysis, upper value from Fig. 19 with assumptions for Europe including capital cost at $450/kW and variable electricity at $47/MWh.	3.24
	Electrolysis, upper value from Fig. 19 with assumptions for India including capital cost at $450/kW and variable electricity at $19/MWh.	1.72
	Electrolysis, upper value from Fig. 19 with assumptions for Japan including capital cost at $450/kW and variable electricity at $63/MWh.	4.24
	Electrolysis, upper value from Fig. 19 with assumptions for Middle East including capital cost at $450/kW and variable electricity at $25/MWh.	1.66
	Electrolysis, upper value from Fig. 19 with assumptions for North Africa including capital cost at $450/kW and variable electricity at $23/MWh.	1.60
	Electrolysis, upper value from Fig. 19 with assumptions for United States including capital cost at $450/kW and variable electricity at $31/MWh.	2.25
IRENA 2019 [4]	Electrolysis with capital cost at $200/kW and electricity at $20/MWh.	1.42
	Electrolysis with capital cost at $370/kW and electricity at $23/MWh.	1.08
	Electrolysis with capital cost at $370/kW and electricity at $22/MWh.	2.06
	Electrolysis with capital cost at $200/kW and electricity at $23/MWh.	1.55
IRENA 2020 [38]	High point of future electrolysis estimate.	1.18
	Mid. point of future electrolysis estimate.	0.95
	Low point of future electrolysis estimate.	0.73
IEA 2020 [37]	Hydrogen cost via electrolysis – lowest 2050 value from Figure 2.14.	1.32
	Hydrogen cost via electrolysis – highest 2050 value from Figure 2.14.	3.34
BNEF 2020 [16]	Renewable H2 – highest 2030 value.	2.73
	Renewable H2 – lowest 2030 value.	1.16
	Renewable H2 – highest 2050 value.	1.66

(*continued on next page*)

Table A7 (*continued*)

Source	Description	LCOH (USD/kg)
	Renewable H2 – lowest 2050 value.	0.71
Estimates from section 4.3.2 using 2030 LCOE data from IRENA 2020 (shown in Fig. 3)	Electrolysis with capital cost at $1000/kW, capacity factor at 30% and electricity at $20/MWh.	2.37
	Electrolysis with capital cost at $1000/kW, capacity factor at 45% and electricity at $31/MWh.	2.44
	Electrolysis with capital cost at $500/kW, capacity factor at 30% and electricity at $20/MWh.	1.76
	Electrolysis with capital cost at $500/kW, capacity factor at 45% and electricity at $31/MWh.	2.04
Estimates from section 4.3.2 using 2030 LCOE data from GenCost 2020 [86]	Electrolysis with capital cost at $1000/kW, capacity factor at 30% and electricity at $18/MWh.	2.25
	Electrolysis with capital cost at $500/kW, capacity factor at 30% and electricity at $18/MWh.	1.63
	Electrolysis with capital cost at $1000/kW, capacity factor at 45% and electricity at $31/MWh.	2.48
	Electrolysis with capital cost at $500/kW, capacity factor at 45% and electricity at $31/MWh.	2.07

Appendix B. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.apenergy.2021.118145.

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