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The Department for Energy Security & Net Zero

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Sent by email to: hydrogenpower@energysecurity.gov.uk

Dear Sir or Madam

Hydrogen to Power: Consultation on the Need, and Design, for a Hydrogen to Power Market Intervention

Thank you for the opportunity to respond to the above consultation. This is a non-confidential response on behalf of Centrica plc.

We broadly support the Government's proposals to support the Hydrogen to Power (H2P) sector and see a clear need to develop and introduce a policy mechanism to support investment in H2P applications across the full range of sizes and technology types.

Our key recommendations are:

- Government must consider the whole energy system, to fully decarbonise the power system at the lowest cost to consumers. Joined-up thinking is required within Government to ensure the development of critical transport and storage infrastructure and roll out of H2P plants go hand in hand.
- Government should undertake in depth analysis and a mapping exercise on future low carbon hydrogen availability, to inform its strategic planning of where and when H2P plants can realistically be deployed. Geography and locational factors such as access to infrastructure and local fuel supply will be critical to determine what is the right H2P solution for the specific location.
- A full range of options and technologies must be considered, including:
    - decentralised, behind the meter CHP plants. Government should consider an interim business model to support non-pipeline hydrogen transport, to deliver hydrogen to more decentralised locations where pipeline transport will not be available in the short term; and
    - ammonia to power technologies, which can help decarbonise the power sector particularly at locations such as UK ports where infrastructure to import and handle ammonia is being developed.
- We agree that for early investments a Dispatchable Power Agreement (DPA) is the most appropriate mechanism, as it de-risks investments by providing regular payments, can be designed to mitigate fuel availability and cross chain risks for investors, and it is well understood. We would encourage Government to extend the scope of the DPA to 'hydrogen blend ready' plants, given that blends will be a critical steppingstone to transition to 100% hydrogen plants and the capex involved to take high blends is still significant.
- We agree that smaller, less capex intensive plants such as hydrogen peakers should be able to participate in the Capacity Market, however these will face similar challenges as larger plants in terms of accessing the fuel, infrastructure and other cross chain risks. The Capacity Market doesn't currently offer any protection against those risks. The design of the Capacity Market must

therefore be reconsidered to mitigate these risks if such plants are to deploy, particularly in the early days of the hydrogen economy where these risks are significant.

Relevance of proposals to Centrica

Centrica plc is a leading energy services and solutions provider founded on a 200-year heritage of serving people. This consultation is particularly relevant to the arms of Centrica listed below.

Centrica Business Solutions

Centrica Business Solutions (CBS), part of Centrica plc, works with businesses across the UK, Ireland, Europe, and North America to provide energy insights, optimisation, and on-site generation solutions that our customers need to achieve their goals. We have a diverse customer base across the private and public sectors including around 90 UK hospitals and local authorities. The technologies CBS works with include Combined Heat and Power (CHP) plants and gas peakers.

Our former UK plant in Salford had enabled us to design, manufacture, install, operate, maintain, and finance CHP plants and complete energy centres since 1984. These include natural gas, biogas, and micro-CHP systems in a wide range of sizes from 4kW to 2MW using the best available engines such as MTU, Perkins, Caterpillar, and MAN. We also have a partnership with 2G Energy AG to provide customers with 100% hydrogen ready CHP systems.

CBS have also recently started to work on a new 20MW gas-fired peaking plant in Redditch, Worcestershire, which will be capable of burning a blend of natural gas and hydrogen, as part of Centrica's plans to deliver around 1GW of flexible energy assets. These include the redevelopment of several legacy-owned power stations, including the transformation of the former 49 MW Brigg Power Station in Lincolnshire into a battery storage asset and the first plant in the UK to be part fuelled by hydrogen. CBS has also recently secured funding under the Net Zero Technology Centre's £8million Open Innovation Programme to inject hydrogen into Brigg's existing gas peaking plant as part of a UK first trial with HiiROC aimed at better understanding the role of hydrogen in power production.

Centrica Energy

Centrica Energy (CE) is the energy trading and optimisation arm of Centrica plc. It trades LNG, gas, power and energy attributes and connect independent producers, suppliers and corporate off-takers in the wholesale energy markets. We also trade LNG globally, connecting supply in places like the US with demand in places like Europe and Southeast Asia, including import of LNG into the UK through our long-term capacity position at the Isle of Grain. CE is currently exploring the potential to import clean ammonia into the EU and the UK from a number of locations outside the EU, for applications such as power generation.

Bord Gáis Energy

Bord Gáis Energy (BGE), also part of Centrica, provides energy supply, services and solutions to over 730,000 residential and business customers in the Republic of Ireland. The business owns and operates a 445MW gas power generation (CCGT) plant in Whitegate, Co. Cork, and is investing in two 100MW flexible gas peaking plants in Athlone and Dublin. Bord Gáis took is investing €250 million in two new hydrogen-ready gas-fired electricity plants to bring flexible and readily available electricity to the Irish market.

Centrica have recently signed a Memorandum of Understanding (MOU) with Mitsubishi Power Europe Limited to explore the development, construction, and operation of Europe's first-ever ammonia-fired power generation facility at Bord Gáis Energy's Whitegate Combined Cycle Gas Turbine (CCGT) power station in Cork, Ireland.

Cen*trica Energy Storage Limited (CESL)*

CESL owns and operates the largest UK gas storage facility at Rough, which was reopened in 2022. The reopening of the facility has helped support security of gas supplies and moderate price volatility during the recent crisis. Centrica has plans to extend and modernise the facility so that it can continue to provide this important system function with the potential to convert to Hydrogen storage during the 2030s.

We look forward to future engagement with you and other industry parties. We have provided answers to the specific consultation questions in the annex below.

I hope you find these comments helpful but please contact me if you have any questions.

Yours faithfully,

Dr Kiara Zennaro

Regulatory Affairs Manager – Biomethane, Hydrogen and GB Gas - Centrica

Responses to consultation questions

1. What are your views on the vision we have set out for hydrogen to power?

Government must consider the whole energy system, to decarbonise the power system at the lowest cost to consumers.

We support Government's view that H2P will play a crucial role to decarbonise our power system. However, any policy intervention from Government should not consider the H2P sector in isolation but needs to consider the whole system interactions to deliver full consumer value.

Connecting supply with demand through the roll out of effective transportation and storage infrastructure at pace will be critical to drive efficiencies, reduce whole system costs and decarbonise the power system at the lowest cost to consumers. Our detailed modelling work shows that the critical value of hydrogen in decarbonising the power sector is driven considerably by ensuring sufficient hydrogen storage is available, combined with the roll out of an interconnected national hydrogen backbone. These can significantly improve the efficiency of using renewable and hydrogen assets by:

- improving the ability to store energy across seasons and also manage shorter-term volatility between renewable generation peaks and troughs;
- allowing hydrogen prices to reduce during peak power periods and improving the competitiveness of hydrogen-fuelled relative to gas-fuelled generation; and
- provide security of supply as the role of unabated gas in a decarbonised system becomes limited.

We would be happy to share with DESNZ further detail about the modelling work we have undertaken and the benefits to consumers of sufficient investment in transport and storage infrastructure.

Joined-up thinking is required within Government to ensure the development of critical infrastructure and roll out of H2P plants go hand in hand.

Strategic planning and joined-up thinking is required between Government departments to ensure the timing of and procurement ambition of critical infrastructure and hydrogen to power plants is fully coordinated.

In particular, H2P will be heavily dependent on access to large underground hydrogen storage being available.

This is confirmed by both Centrica's own modelling and also independent research such as the *Second National Infrastructure Assessment* (the Assessment)[1], published in October 2023. This contains recommendations about the expected capacity of hydrogen-fired generation and the required storage capacity that should be in operation by 2035. The assessment states that Government should target a minimum of 8 TWh of large-scale hydrogen storage to be in operation by 2035 and, by the same year, that deployment of low carbon gas generation and storage facilities should be sufficiently scaled to provide 30TWh of reliable flexible generation to manage the potential for prolonged shortfalls during winter.

DESNZ, however, have only proposed to support up to two hydrogen storage projects in the first allocation round of the Hydrogen Storage Business Model (HSBM). The typical capacities of projects that could be awarded HSBM contracts in the first allocation round are relatively small. For example, salt cavern storage tends to be of several orders of magnitude smaller than the 2035 target: GWh-

[1] 'The Second National Infrastructure Assessment', page 43.

scale instead of TWh-scale facilities. These factors suggests that the Government will fall significantly short of the 8 TWh target, which is likely to have a knock-on effect on the capacity of H2P plants that can be deployed and could increase system costs significantly, given the interdependency between hydrogen storage and H2P. We have responded separately to the government's market engagement on this topic.

A sensitivity analysis by Afry found that delayed implementation undermines the value of electrolysing excess renewables for later use in H2P plants, resulting in 68% increase in curtailment, a £1.7bn increase in system costs and a substantial reduction in the role of H2P (from 80TWh to 18TWh) by 2035.[2]

Locational factors and geography must be considered to inform the choice of the right H2P solution for the specific location. Government needs to undertake detailed analysis and mapping to inform its strategic planning of where and when H2P plants can be deployed.

One of the greatest risks that hydrogen to power plant developers will face in the early days of the hydrogen economy is whether these plants can reliably access low carbon hydrogen. This will only be enabled if the strategic infrastructure to store and deliver the hydrogen to the generator is in place at the plant-specific location.

In its vision Government has not taken into account locational factors such as access to key infrastructure and local low carbon hydrogen supply/availability. The most appropriate solutions and optimal siting of H2P plants will ultimately depend on these factors.

As an example, there are UK ports or terminals where infrastructure to import and handle ammonia is being built, such as Immingham in the Humber Industrial Cluster and Stanlow in the Hynet cluster. At these locations an ammonia to power station may makes more sense than a H2P station given the proximity to critical infrastructure and greater access to the fuel.

It is unclear from the consultation document whether DESNZ has a clear vision of how much low carbon hydrogen will become available and at which locations. We would strongly encourage Government to undertake a full assessment and mapping of what volumes of low carbon hydrogen are likely to become available and when, as well as their likely locations. This analysis can then inform the Government strategic planning of where hydrogen to power plants can be realistically deployed and when. It will also help understand at what point these plants can be deployed through existing markets.

A full range of H2P options must be considered, including decentralised CHP plants and ammonia to power technologies.

We also believe it is important Government considers the full range of options (technology types and scales) to decarbonise the power system. There is no 'one size fits all approach'.

Whilst we believe large scale plants (e.g. CCGT and CCHT) as well as smaller plants (OCGT and OCHT) will play a significant role, we also expect to see a decentralised, regional approach which utilises different technology combinations depending on what is most appropriate for a particular region. For example, hydrogen clusters will develop where there are areas of high industrial demand, local storage solutions, and hydrogen production facilities. In other areas, factors such as constraints on the local electricity network or local geography will mean that microgrid solutions and decentralised, behind the meter CHP systems could be the most suitable approach.

[2] "Net Zero Power and Hydrogen: Capacity Requirements for Flexibility." Afry (2023).

Centrica have around 1,200 decentralised CHP installations i.e. behind the meter installations deployed mostly within the hospitality sector, Manufacturing, hospitals or other small non-domestic users which typically have high energy (heat and power) requirements. In most cases these premises are hard to electrify because of challenges associated with grid connections. In these situations, behind the meter hydrogen CHP technology could offer the only solution to decarbonise energy demand. However, whilst the technology readiness of these solution is already very high, the main challenge will be to deliver the fuel (low carbon hydrogen) to these decentralised sites, especially if they are located outside the clusters and away from any transport and storage infrastructure. Non-pipeline hydrogen transport (e.g. tankering) would provide an ideal solution but it is currently not supported by the Government and consideration would need to be taken in terms of storage of suitable volumes of hydrogen onsite.

We would therefore encourage the Government to consider an interim business model to support non-pipeline hydrogen transport, to support the decarbonisation of the power system via more decentralised solutions.

Up to now there has been a gap in policy support for smaller-scale, distributed assets. It is critical that the Government does not close any doors at this stage and provides the support necessary to allow these technologies to contribute to achieving net zero. The consultation document doesn't seem to mention CHP engines at all, whilst the supporting analysis undertaken by LCP Delta appears to have only considered large scale CHP in front of the meter.

We therefore encourage DESNZ to consider in their policy proposals all ranges of hydrogen to power applications, including the full range of combined heat and power (CHP) engines, both behind and in front of the meter.

In addition, whilst we agree that hydrogen to power applications are going to play a crucial role in decarbonising the power system, the focus on hydrogen as is too narrow. Government should also consider other power generation technologies that are emerging in the market - such as ammonia to power and CHP engines that use hydrogen/nitrogen blends.

Hydrogen imports in the form of hydrogen derivatives such as ammonia may be required to deliver energy security and support demand whilst domestic production gets up to speed. As previously mentioned, there are UK ports or terminals where infrastructure to import and handle ammonia is being built, such as Immingham in the Humber Industrial Cluster and Stanlow in the Hynet cluster. At these locations an ammonia to power station may makes more sense than a H2P station given the proximity to critical infrastructure and greater access to the fuel.

If, however, Government continues to be focused on H2P technology, then the cost of cracking hydrogen out of ammonia would need to be factored in somewhere in the relevant business models to make this viable. Currently, this cost is not included in the hydrogen production business model and is also not included in the cost assumptions made in the analysing supporting this consultation.

2. In your view, what role should hydrogen to power plants be playing in the power system? Please provide details and an explanation of your reasoning.

We broadly support the vision set out by Government ie that H2P will have a variety of roles in the power market. These range from a short-term peaking role to providing services to the system operator and longer duration running to cover extended periods of reduced renewable generation.

3. Do you agree with our assessment that less CAPEX-intensive plants and/or plants with ready access to low carbon hydrogen fuel could deploy in the short term without bespoke support? Please provide an explanation of your reasoning.

We broadly agree that less CAPEX intensive plants such as hydrogen peakers that require minor engineering modifications should be able to compete under the current Capacity Market (CM), provided these plants have guaranteed access to low carbon hydrogen. The current clearing prices in the Capacity Market should be sufficient to underwrite the capex cost of the peaker plus a small upside. Provided the plant is reliable and has reliable access to the fuel, in theory the Capacity Market should enable roll out of these plants. However, it is not clear whether any plant will have access to sufficient volume of hydrogen to deploy in the short term. Nor is it likely that such hydrogen supply would be sufficiently reliable for plants to participate in the CM, given the risk of non-delivery penalties.

It is important to recognise that these plants will face similar challenges as the larger plants in terms of access to the fuel, infrastructure and other cross chain risks and, therefore, the design of the CM needs to be reconsidered to address these risks. It currently doesn't provide a mitigation against these risks.

DESNZ also need to consider whether 'hydrogen blend ready' gas peakers should be treated differently from peakers that can run on 100% hydrogen. Our understanding is that most 'hydrogen ready peakers' will run on 100% natural gas but have the option to run on up to 25 - 30% hydrogen blend with only minor modification. Peakers that run on higher hydrogen blends (> 30%), however, will require more extensive engineering modifications which will in turn add significant extra capital costs.

As an example, a gas peaker taking up to 25 – 20% hydrogen will cost around £600k - £650K/MW (excluding grid connection costs), whilst for a hydrogen-ready plant taking > 30% blend, an extra 15% cost should be factored in, as the gas engine will require extensive modifications.

In addition, due to the lower calorific value of hydrogen the power output would also likely drop by around 35% (a plant using natural gas rated at 20MW would drop to 13.5MW output).

As for CHP engines, these can be converted quickly (weeks) to run on hydrogen on a dual gas train. The hydrogen readiness level of CHP engines is typically high, however, similarly to peakers, the engine will need to be de-rated for operational performance. An engine will reduce its electrical output by 20-25% when changing the fuel source from methane to hydrogen. Therefore, appropriate de-rating factors for different types of H2P plants in the CM need to be considered.

Further considerations on the Capacity Market:

- Currently it is not possible to deploy H2P plants under the Capacity Market as there isn't a specific category for hydrogen. This will need adding.
- Under the CM generators can only bid four years out and there are specific milestones that need to be met once the contract is awarded to ensure the plant is constructed and become operational within a specified timescale. It will be important to understand whether these milestones are suitable for H2P plants.
- There are annual contractual obligations under the CM to meet a performance test, showing that the relevant capacity has been delivered. Failing to meet this test results in significant fines (currently £15,000/MW). The reliability of the plant is therefore of utmost importance not to incur significant fines. Given the FOAK nature of H2P plants and the risks associated with access to the fuel and other cross chain risks, this could be a challenge.
- The methodology that sets out the derating factors for different technologies may need to be reconsidered to reflect different type of H2P applications.

4. What are your views on our proposal to enable hydrogen to power plants to compete in the Capacity Market as soon as practical?

As above, we agree that in theory H2P plants should be enabled to compete in the Capacity Market as soon as practical. In practice, the main challenge for these plants will be to access the fuel and the availability of the required transport and storage infrastructure. Until this is in place, we may see little deployment under the Capacity Market even if these plants are enabled to compete.

As highlighted above, smaller plants will face similar challenges as larger, mid-merit plants in terms of being able to access the fuel, the infrastructure and other cross chain risks and the Capacity Market doesn't currently offer any protection against those risks. This needs careful consideration.

Fuel risk will remain a challenge for all types of H2P plant, particularly in the early 2030s where hydrogen markets are localised with finite production. This is particularly concerning for H2P using green hydrogen as it will be contingent on weather conditions and/or sufficient availability of hydrogen storage. This risk could translate into higher IRR required by investors, which may be reflected within CM bids, particularly due to the non-delivery penalty. DESNZ should conduct a deep review of the rate and cap of the penalty scheme for non-delivery penalty required for H2P entering the CM.

5. Are there any additional changes to existing markets which could support the deployment of hydrogen to power? Please provide details and an explanation of your reasoning.

A mechanism could be built in the Capacity Market similar to that introduced in Ireland for grid connections: along with the availability payment, a guarantee is provided that the plant will get a grid connection. It may be possible to do something similar for hydrogen peakers e.g. introduce a guarantee to the fuel access.

6. Do you agree with the risks and barriers to hydrogen to power deployment that we have identified? Please provide an explanation of your reasoning.

Yes, we broadly agree with the barriers identified in the consultation.

Transport and storage infrastructure

The largest challenge remains the lack of transport and storage infrastructure and therefore risks associated with fuel availability, which highlights the importance of a joined-up policy approach across hydrogen to power, transport and storage, as well as hydrogen production. There is significant uncertainty on whether the critical networks will be available by the time the planned H2P asset comes online, making it difficult to justify investment in these early stages of the hydrogen economy. There needs to be alignment between the roll out of H2P generation and the development of the critical infrastructure.

Along with the uncertainty and risks associated with the roll out of the hydrogen transport and storage infrastructure and access to the fuel, other barriers are:

Risk-taking intermediaries' exclusion

The exclusion of risk-taking intermediaries (RTI) under the Hydrogen Production Business Model. Risk taking intermediaries can take on roles in the nascent and developing hydrogen economy that they are best placed to manage efficiently, including contracting with producers, storage operators, customers, suppliers (depending on supply licence considerations) and the pipeline operator for transportation and balancing services. Without RTIs, producers are incentivised to opt for offtakers that will require consistent volumes, particularly in the absence of large-scale transport and storage infrastructure. This is problematic for H2P assets supplied by green hydrogen as they tend to have uncertain loads.

Technical challenges

There are also technical challenges that needs to be considered in the short term, which we have set out in our response to question 3. There is also further consideration in how hydrogen would be delivered and stored onsite.

7. In your view, what should industry's role be in addressing the barriers that we have identified? Please provide details and an explanation of your reasoning.

Industry can support Government in identifying where critical infrastructure is likely to be built and where low carbon fuels such as hydrogen and ammonia are likely to become available and when. This will help inform DESNZ strategic planning of the roll out of H2P plants.

8. Are there any other potential risks and barriers that we should be considering? If so, which ones? Please provide details and an explanation of your reasoning.

Please see our answer to question 6.

9. Do you agree with our assessment that bespoke hydrogen to power market intervention is required to mitigate our identified deployment barriers and accelerate the deployment of hydrogen to power plants, likely those which are more CAPEX-intensive? Please provide an explanation of your reasoning.

Yes, we agree that a bespoke market intervention is required to support capital intensive hydrogen power plants because of the market barriers identified associated with the nascent hydrogen market and FOAK technologies.

10. Have we considered all credible market intervention options for hydrogen to power? Please provide details of any design options you think we may have missed and explain your reasoning.

Yes, we believe DESNZ has considered all credible options that are available.

11. Do you agree with our shortlisted three market intervention design options? Please provide an explanation of your reasoning.

Yes, we believe DESNZ has shortlisted the right market interventions.

12. Have we accurately identified the benefits and risks of a DPA-style mechanism? If not, are there any further benefits and risks to consider? Please provide details and an explanation of your reasoning.

Yes.

13. Do you agree with government's assessment that a mechanism based on the Dispatchable Power Agreement is the most suitable option for bespoke hydrogen to power market intervention to support the accelerated deployment of hydrogen to power? Please provide an explanation of your reasoning.

Yes,

For early investments the DPA is the most appropriate mechanism as it de-risks investments by providing a regular payment and can be designed to mitigate fuel availability and cross chain risks for investors. In addition is a well understood scheme that is already been sued for Power CCUS developers.

However, we encourage Government to expand the scope of this bespoke mechanism to 'hydrogen blend ready' plants, given that blends will be a critical steppingstone to transition to 100% hydrogen plants and the capex involved to take high blends may still be significant.

The engine manufacturers for our power station at Whitegate (9Fb unit), GE, has stated that the plant can utilise up to 10% blend of hydrogen by volume, with little or no impact on the plant. Above 10% by volume, then we are entering a slightly different zone for potential upgrades and a sizeable engineering effort may be required. It is not clear at this stage what would be required and that would be determined via the 'sizeable engineering effort' - but the expectation is that anything above 20% by volume would require significant CAPEX.

14. What are your views on the need for a Variable Payment? Please provide details and an explanation of your reasoning.

We broadly agree with DESNZ that introducing a Variable Payment may risk causing market distortions. Provided the fuel is subsidised and can be accessed, then a variable payment should not be required. However, we feel further analysis should be undertaken to understand whether an availability only payment would be sufficient for H2P plants to deploy given the risks and uncertainties they face associated with fuel availability and the other factors previously highlighted.

15. Have we accurately identified the benefits and risks of a Split CM? If not, are there any further benefits and risks to consider? Please provide details and an explanation of your reasoning.

Yes, the risks have been clearly set out in the consultation.

16. Do you agree with our proposal to discount the Split CM as an option for bespoke hydrogen to power market intervention to support the accelerated deployment of hydrogen to power? Please provide an explanation of your reasoning.

Yes, we would agree this option is premature and would not work given the penalties plant operators would incur when they cannot meet the security of supply conditions.

H2P assets are at increased risk of exposure to non-delivery penalty due to fuel and cross-chain risks associated with the emerging low carbon hydrogen economy. Although the secondary market in the CM that allows trade of CM obligations can help minimise the risk of these penalties.

17. Have we accurately identified the benefits and risks of a Revenue Cap and Floor?

Yes, the assessment of the benefits and risk of a Revenue Cap and Floor is comprehensive.

If not, are there any further benefits and risks to consider? Please provide details and an explanation of your reasoning.

NA

18. Do you agree with our proposal to discount the Revenue Cap and Floor as an option for bespoke hydrogen to power market intervention to support the accelerated deployment of hydrogen to power? Please provide an explanation of your reasoning.

Yes, we agree that a cap and floor mechanism has the potential to distort dispatch in suboptimal ways.

19. What is your view on the need for price-based competitive allocation within/between bespoke business models versus moving assets straight to a technology-wide competitive market? Please provide an explanation of your reasoning.

While price-based competition is a useful means to drive cost reduction in the longer term, introducing price-competitive allocation too early could lead to negative outcomes. More widely there will eventually be a need to adopt more technology neutral support mechanisms. However, for new technologies such as hydrogen, more bespoke selection process is required that takes into account the locational nature of hydrogen investments in terms of availability of hydrogen and infrastructure.

20. How should a bespoke hydrogen to power business model be evolved to promote competition between low carbon flexible technologies? Please provide details and an explanation of your reasoning.

It is too early for evolve into a competitive mechanism, see above.

21. What are your views on the alignment of hydrogen support and policies needed to enable the deployment of hydrogen to power capacity. Please provide details and an explanation of your reasoning.

See previous answers.

22. Do you have any reflections on the feasibility of hydrogen producers, or qualifying offtakers, to facilitate the volume of storage required for hydrogen to power – for example, regarding sourcing finance/capital? Please provide details.

NA

23. What are your views on the feasibility of developing commercial arrangements between hydrogen producers, storage providers, and electricity generators that meet the Hydrogen Production Business Model (HPBM) requirements relating to Risk Taking Intermediaries (RTIs)?

RTIs are a fundamental part of any market for matching supply and demand and managing that risk on behalf of the producer and offtaker. By excluding RTIs from the HPBM, this increases the risk premium of projects thereby making it harder to develop and finance.

For H2P assets in particular, the exclusion of RTIs exacerbates fuel risk and cross-chain risk. The value of RTIs is that they can take on the risk of moving hydrogen from A to B, and then into storage. This reduces H2P developers' exposure to the risks previously mentioned and thereby makes the cost of both the CM and DPA lower.