1. Data and Values for Carbon Intensity
    a. Many parameters that can influence the lifecycle emissions of hydrogen production may vary in real-world deployments. Assumptions that were made regarding key parameters with high variability have been described in footnotes in this document and are also itemized in the attached spreadsheet "Hydrogen Production Pathway Assumptions." Given your experience, please use the attached spreadsheet to provide your estimates for values these parameters could achieve in the next 5-10 years, along with justification.
    b. Lifecycle analysis to develop the targets in this draft CHPS were developed using GREET. GREET contains default estimates of carbon intensity for parameters that are not likely to vary widely by deployments in the same region of the country (e.g., carbon intensity of regional grids, net emissions for biomass growth and production, avoided emissions from the use of waste-stream materials). In your experience, how accurate are these estimates, what are other reasonable values for these estimates and what is your justification, and/or what are the uncertainty ranges associated with these estimates?

In EQT's experience, the GREET Model in its current configuration over-inflates EQT's emissions by an order of magnitude. Due to EQT's pursuance of clean hydrogen technologies, the GREET model will be the basis for EQT's reporting of emissions of its hydrogen production from its natural gas production. However, when looking at the research methods and assumptions used when reporting natural gas GHG emissions numbers, there are significant discrepancies in the input natural gas emissions factors used in the model that need to be remedied. The average GHG emissions for Natural Gas production are based on specific research performed early in the lifetime of shale based natural gas production and extraction, which do not consider the aggressive emissions reduction efforts of recent years. These studies, which are referenced in the most updated version of the GREET model's updated natural gas pathways report, particularly the Clark et al. study on the lifecycle of natural gas performed in 2011 and the Lee assessment of methane emissions from natural gas performed in 2018, as well as data reports from the in 2011 and 2013, are unable to produce accurate assumptions concerning the emissions resulting from natural gas production. This updated pathway also points to major underreporting of methane emissions from the EPA, citing discrepancies between the bottom-up and top-down emission calculations. The renegade methane is then credited to natural gas production even though the EPA itself says that this methane could be from any other source such as coal mines or landfills.

The GREET model then takes the data and applies it to all natural gas production, without the nuance of other factors imperative to calculating total emissions. These reports rely on data collected before significant changes had been implemented by natural gas producers, especially EQT, leading to reduced amounts of GHG emissions across the lifecycle. These implemented changes have successfully altered the average emissions of EQT's natural gas production and have increased the overall efficiency of their systems. These processes such as adopting stringent net zero operations as a company and enacting technological advances such as pneumatic device replacement to trap escaping gasses and leak detection program, have greatly reduced average emissions from EQT's operations.

In using assumptions based on outdated research in the GREET model, the average emissions of EQT are overestimated, making the process of achieving net zero activities and pursuing EPA compliance difficult and incorrect, as well as keeping to the policies agreed upon in the BIL. These discrepancies are evident in the following table which compares EQT's average emissions from operations in 2020 in gCO2 eq/MMBTU to the GREET model estimations based on user input data using the same emissions factors and carbon intensities. As denoted in the table below the GREET model emission factors are approximately five times larger than the actual reported factors from EQT.

GREET Model Emission Factors		GREET	GREET	EQT 2020	EQT 2021
	Units	EPA Conv	EPA Shale	EQT Shale	EQT Shale
Recovery - CH4 Leakage and Venting	g CO2eq/MMBtu NG	2277	2364	374	311
Recovery - Completion CH4 Venting	g CO2eq/MMBtu NG	15	85		
Recovery - Workover CH4 Venting	g CO2eq/MMBtu NG	0	16		
Recovery - Liquid Unloading CH4 Venting	g CO2eq/MMBtu NG	125	125		
Well Equipment - CH4 Venting and Leakage	g CO2eq/MMBtu NG	1278	1278		
Gathering and Boosting - CH4 Venting and Leakage	g CO2eq/MMBtu NG	859	859		

There have been updates to the most recent GREET 2021 model when concerning natural gas, however these updates to the boundary system and a recognition of the EPA's limitations and own incorrect estimates are still using the outdated research as a basis. When looking at new research and from the average emissions shown in natural gas company's ESG reports, it is evident that the discrepancy between the GREET model and the available data is justified and worth reevaluating. We believe that the GREET model would be more effective at gauging net emissions if our proposed changes are considered, however, we are not questioning the use of GREET or implying that it should not be used for this BIL.

c. Are any key emission sources missing from Figure 1? If so, what are those sources? What are the carbon intensities for those sources? Please provide any available data, uncertainty estimates, and how data/measurements were taken or calculated.

EQT does not believe that there are any missing emission sources from Figure 1 and accepts the boundaries in the BIL.

d. Mitigating emissions downstream of the site of hydrogen production will require close monitoring of potential CO2 leakage. What are best practices and technological gaps associated with long-term monitoring of CO2 emissions from pipelines and storage facilities? What are the economic impacts of closer monitoring?

EQT, as the largest natural gas producer in the U.S., is deeply familiar with and well equipped to monitor fugitive CO2 emissions from pipelines and storage facilities. There are multiple best practices to maximize the long-term monitoring of these emissions that are commercially feasible. One of the most effective would the use of pneumatic devices for the control of liquids across the various pieces of equipment essential for natural gas production. The use of these pneumatic devices (low bleed or intermittent bleed) has drastically reduced fugitive emissions and resulted in a decrease of 96% for GHG emissions.[1] One of the most effective means of long-term monitoring that has been extremely successful for EQT is the adoption of LDAR surveys and optical gas imaging. This practice can effectively monitor large production areas and pipelines and has notably reduced the number of leaking components on EQT's production sites and decreased the lag time between detection and repair. This technology adaptation requires a relatively high economic investment, but the reduction of leaks and down time quickly offsets incurred costs.

e. Atmospheric modeling simulations have estimated hydrogen's indirect climate warming impact (for example, see Paulot 2021).19 The estimating methods used are still in development, and efforts to improve data collection and better characterize leaks, releases, and mitigation options are ongoing. What types of data, modeling or verification methods could be employed to improve effective management of this indirect impact?

For estimating methods to be more effective, there needs to be more comprehensive data collected as the production sites operate. Currently, the lack of major production facilities across the world has stymied the estimation of hydrogens climate impact. As with all estimation calculations, more data is needed to provide concrete impacts of hydrogen. However, as the climate impact of hydrogen is being developed, it is still orders of magnitude less than that of traditional fossil fuels, which indicates that the development and implementation of hydrogen hubs should be pursued in tandem with estimation methods, not after. Independent verification through 3rd parties is necessary to determine impact and should be required throughout the production process.

f. How should the lifecycle standard within the CHPS be adapted to accommodate systems that utilize CO2, such as synthetic fuels or other uses?

The lifecycle standard used within the CHPS needs to be updated to reflect other carbon sequestration methods that are as effective as well injection and should be considered when looking at overall emissions of hydrogen production. Without this addition, the CHPS is reducing the effectiveness of hydrogen hubs to sequester more of their emissions with other verified sequestration methods. Nature-based sequestration methods should be considered as a viable alternative to deep injection as, in areas around the country, injection is not a viable option. Appalachia, the location of EQT's planned hydrogen hub, has a difficult sub-surface geology for the injection of CO2 that makes well sites highly uncertain and will result in significant delays for potential commercial hydrogen projects. This places the Appalachian Region, the home of many disadvantaged communities and the subject of numerous environmental justice issues due to the legacy of coal mining, at a disadvantage in its transition to clean energy. The CHPS should promote other certified processes for the sequestration of CO2 in order to

[1] More Information can be found: https://esg.eqt.com/environmental/climate-and-ghg-emissions/#strategic-initiatives

assure an equitable opportunity for significant regions of the county to participate in the energy transition.

2. Methodology
    a. The IPHE HPTF Working Paper (https://www.iphe.net/iphe-working-papermethodology-doc-oct-2021) identifies various generally accepted ISO frameworks for LCA (14067, 14040, 14044, 14064, and 14064) and recommends inclusion of Scope 1, Scope 2 and partial Scope 3 emissions for GHG accounting of lifecycle emissions. What are the benefits and drawbacks to using these recommended frameworks in support of the CHPS? What other frameworks or accounting methods may prove useful?

The benefits for using these frameworks are manyfold. The universal nature of the ISO frameworks allows for an effective baseline to compare emissions across different facets of production and allow for maximum application as they are the most used LCA frameworks. In examining how these frameworks support CHPS, the streamlined emissions calculations and boundary formations are effective in portraying the complexities of hydrogen production.

    b. Use of some biogenic resources in hydrogen production, including waste products that would otherwise have been disposed of (e.g., municipal solid waste, animal waste), may under certain circumstances be calculated as having net zero or negative CO_2 emissions, especially given scenarios wherein biogenic waste stream-derived materials and/or processes would have likely resulted in large GHG emissions if not used for hydrogen production. What frameworks, analytic tools, or data sources can be used to quantify emissions and sequestration associated with these resources in a way that is consistent with the lifecycle definition in the IRA?

The most effective framework for this quantification would be the EPA established framework for biogenic CO_2 emissions and their sequestration potential. This framework contains the necessary information to determine the consistency of biogenic waste with the IRA and will allow for a robust quantification of sequestration and emissions.

    c. How should GHG emissions be allocated to co-products from the hydrogen production process? For example, if a hydrogen producer valorizes steam, electricity, elemental carbon, or oxygen co-produced alongside hydrogen, how should emissions be allocated to the co-products (e.g., system expansion, energy-based approach, mass-based approach), and what is the basis for your recommendation? d) How should GHG emissions be allocated to hydrogen that is a by-product, such as in chlor-alkali production, petrochemical cracking, or other industrial processes? How is byproduct hydrogen from these processes typically handled (e.g., venting, flaring, burning onsite for heat and power)?

The most effective way to incorporate GHG emissions to multi-product processes is through system expansion that allows for the development of an expanded functional unit in LCA determination. In using system expansion, the LCA can avoid allocation which would produce skewed results across the co-products and confuse the emissions surrounding hydrogen production. The basis for this comes from the ISO LCA standards surrounding multi-product processes. For the hydrogen as a byproduct, system expansion should also be used to accurately determine emissions across the production process. The byproduct hydrogen is typically used as a fuel for the manufacturing process where it was produced. This would be factored into the system expansion.

3. Implementation
    a. How should the GHG emissions of hydrogen commercial-scale deployments be verified in practice? What data and/or analysis tools should be used to assess whether a deployment demonstrably aids achievement of the CHPS?

By using third-party verification bodies such as Verra or ACR, GHG emissions can be effectively quantified and verified throughout the lifecycle. The most pertinent data would be emissions data across the boundaries outlined by the CHPS which would give a clear picture of the production system. There needs to be a comprehensive system to depict how a deployment produces hydrogen and if they are falling within the CHPS goals.

    b. DOE-funded analyses routinely estimate regional fugitive emission rates from natural gas recovery and delivery. However, to utilize regional data, stakeholders would need to know the source of natural gas (i.e., region of the country) being used for each specific commercial-scale deployment. How can developers access information regarding the sources of natural gas being utilized in their deployments, to ascertain fugitive emission rates specific to their commercial-scale deployment?

Producers of hydrogen utilizing natural gas will know their suppliers and have a basis of their geographical origins. Natural gas suppliers have the information concerning their own fugitive emissions and have the data to understand the breadth of their emissions, so hydrogen developers would need to contact their natural gas suppliers to understand the emission rates.

    c. Should renewable energy credits, power purchase agreements, or other market structures be allowable in characterizing the intensity of electricity emissions for hydrogen production? Should any requirements be placed on these instruments if they are allowed to be accounted for as a source of clean electricity (e.g. restrictions on time of generation, time of use, or regional considerations)? What are the pros and cons of allowing different schemes? How should these instruments be structured (e.g. time of generation, time of use, or regional considerations) if they are allowed for use? d) What is the economic impact on current hydrogen production operations to meet the proposed standard (4.0 $kgCO_2e/kgH_2$)?

Yes, renewable credits, purchase agreements, and offset generation should be allowable in intensity discussions as hydrogen is a comparatively clean energy and can be used as an effective offset for GHG emissions. One caveat that could affect this categorization would be regional considerations as some areas where hydrogen production is effective does not have the clean energy infrastructure to allow for a greater proportion of clean energy use. In these cases, it is important to understand the suppliers of the traditional fuel sources, the emission from the fuel source production and use, and how this effects the generation of hydrogen. There needs to be recognition of the hydrogen production as a base process to provide clean energy, even if the generation of this hydrogen is from traditional fuel sources. There are many pros for allowing these different schemes, from economic enticement to greater deployment through realized environmental support. Allowing for these plans to be emplaced would result in greater adoption of hydrogen production processes as the environmental and economic benefits would greatly outweigh the initial investment and operational costs. In regards to structure, there should also be a regional component to the market instruments to reflect the diverse nature of hydrogen production around the country. This regional consideration will aid in offset allocation and energy agreements. The economic impact of producing hydrogen under this standard results in greater initial investment costs to implement the many technologies to reduce leakage and allow for clean generation. However, overtime these initial investments will be offset by the economic benefits of clean energy production.

Additional Information

d. Please provide any other information that DOE should consider related to this BIL provision if not already covered above.

Per EQT's comment for question 1(f) regarding enabling accounting of alternate means of carbon storage – namely nature based carbon storage to help qualify hydrogen produced from gas as "blue" in areas where geologic carbon storage is not well understood or available. This concept is comparable to question 3(c) asking for comment on allowance of REC's, offsets and other means to enable displacement of emissions resulting from grid electricity generation being used to produce "green" hydrogen. Conceptually this is the same in that if offsets are able to be used to enable green hydrogen a pathway to circumvent the fact that currently, large scale battery storage is not at the scale needed to enable true 100% green hydrogen and the grid electricity used comes from natural gas and/or coal, then offset mechanisms should be allowed to provide a pathway for areas of the country in which geologic storage is not clearly understood or available to enable "blue" hydrogen from natural gas. In the end, the offset mechanisms are being used to offset the emissions from natural gas combustion or from an SMR/ATR process. Enabling one without the other would be a blatant double standard in interpretation.

Parameter	Assumptions made in analysis supporting proposed targets within draft CHPS	Respondent feedback		
		Regional or national average values achievable within next 5 years (i.e. by 2027)	Regional or national average values achievable in future years, and respective timescale	Rationale for estimates and any additional comments
Fugitive methane emissions	~1% of methane throughput between the point of natural gas drilling to the point of use is assumed to be released through fugitive emissions (e.g. during drilling process, transmission pipelines). This loss rate is estimated to reflect average fugitive methane emissions between natural gas plays across the U.S. and current steam methane reformers. The basis for this estimate is further described in GREET supporting documentation*:* https://greet.es.anl.gov/publication-update_ng_2021 In columns C-E, please provide feedback on the technical and economic feasiblity of this leak rate being accessible regionally or as a national average.	0.20%	0.20%	With the implementation of EQT's emission reductions activities, EQT is highly confident in maintaining industry low fugitive methane emissions that are both low cost and effective. A list of the activities can be found here https://esg.eqt.com/environmental/climate-and-ghg-emissions/#strategic-initiatives
Rate of carbon capture	~95% carbon capture at natural gas reforming facilities and gasification plants is assumed to be commercially deployable, and to enable one path to achieving the targets proposed in this draft guidance. In columns C-E, please provide feedback on the technical and economic feasiblity of this rate of carbon capture being deployed.	~60%	~80% 20 years	The proposed rate of capture is too high to be effective on a commercial scale and will not be effective as a metric for project ability. With one capture unit in the field performing at capcity, a capture rate of 52% is possible. With the installation of another unit, the rate increases are highly variable and the resulting increase in compression machinery offers decreased returns on capture. The efficiency metrics need to be re-examined to allow for increased capture methods and a more attainable capture efficiency rate to be both economically and environmentally viable for the production company. An increase in capture could be attainable if a wider base of carbon sequestration projects are made available and deemed viable, such as nature-based projects.
Share of clean energy within electricity consumption	Use of predominantly clean energy (i.e. $\geq$85% clean energy, $\leq$ 15% U.S. grid mix) in electrolysis is expected to enable achievement of the lifecycle target proposed in this draft guidance. In columns C-E, please provide feedback on the techincal and economic feasibility of electrolyzers accessing this share of clean energy.			This assumption is highly variable depending on production location and grid supply. The use of clean energy for production can enable achievement of emissions targets, but is totally dependent on the growth and development of clean energy, which currently will not meet the energy demands of EQT in West Virginia.
CO2 leak rate from CCS	Leak rates of <1% from CO2 sequestration sites are assumed to be feasible today, and expected to enable achievement of the proposed targets in this draft guidance. In columns C-E, please provide feedback on the technical and economic feasiblity of this CO2 leak rate being achieved.			The leak rate targets are feasible with EQT's emission reduction activities.
Other (e.g. pressure and purity conditions at output of hydrogen production facilities)	In analysis to inform the CHPS, systems were modeled to achieve hydrogen production with 99% purity and 3 MPa at the outlet.			The hydrogen purity and pressure are also feasible.