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Clean Air Task Force (CATF) comments on SB100 draft results

Additional submitted attachment is included below.

CLEAN AIR TASK FORCE

September 15, 2020

California Energy Commission
Docket Unit, MS-4
Docket No. 19-SB-100
1516 Ninth Street
Sacramento, California 95814-5512

Clean Air Task Force Comments on September 2nd Public Workshop on SB 100 Joint Agency Report: Charting a path to a 100% Clean Energy Future

Dear Commissioners Hochschild, Randolph and Nichols,

Clean Air Task Force (CATF) is grateful for the opportunity to submit comments on the recent analysis conducted by the joint agencies and E3 on achieving a net zero emissions grid by 2045 as mandated under the SB 100 law.

Below we offer CATF's recommendations that we believe, if considered, will provide valuable additional analysis and perspective to inform the draft of the Joint Agency Report expected later this year. Also our recommendations would help inform policy decisions supporting specific zero carbon firm generation technologies in meeting California's carbon neutrality goal by 2045.

1. The "study" scenarios requiring full power system decarbonization should be the primary scenarios examined, and the agencies should not prioritize the "core" scenarios that exclude carbon emissions associated with electricity lost in transmission, distribution and storage

As CATF explained in previous comments submitted December 2, 2019, the clear intent of SB 100 is to achieve a carbon-free electric system serving California load by 2045. Yet the presentation relegates the "system" perspective to an alternate "study" category rather than being the principal category analyzed, while the "core" scenario limits its analysis only to net kilowatt hours delivered, ignoring T and D and storage losses. T

This approach leaves between 19 and 24 million metric tons of CO2 emitted annually from the California power system (slide 25), an amount equivalent to twice the emissions of the Colstrip coal fired power plant in Montana, the second largest coal plant in the West. We believe this approach remains a significant error of law and policy.

First, such an interpretation is flatly contrary to both the letter and spirit of SB 100. The central requirement of SB 100 reads as follows:

> (a) It is the policy of the state that **eligible renewable energy resources and zero-carbon resources supply 100 percent of all retail sales of electricity** to California end-use customers and 100 percent of electricity procured to serve all state agencies by December 31, 2045. T**he achievement of this policy for California shall not increase carbon emissions elsewhere in the western grid and shall not allow resource shuffling.** The commission and Energy Commission, in consultation with the State Air Resources Board, shall take steps to ensure that a **transition to a zero-carbon electric system for the State of California does not cause or contribute to greenhouse gas emissions increases elsewhere in the western grid,** and is undertaken in a manner consistent with clause 3 of Section 8 of Article I of the United States Constitution. The commission, the Energy Commission, the State Air Resources Board, and all other state

agencies shall incorporate this policy into all relevant planning. **(Emphasis supplied.)**

It is evident from the first sentence that only eligible renewable and zero carbon resources are allowed to "supply" retail sales. In order to **supply** retail sales, it is physically necessary to **generate** enough power to meet demand net of line and distribution losses. The legislature could have easily specified that actual zero carbon or renewable generation need only equal final retail sales, and that the portion of the supply chain that emits carbon be ignored. But it chose not to. Indeed, this would have made little sense. The goal of SB 100 is clearly to eliminate carbon emissions from energy production entirely by mid century, as numerous scientific reports have indicated will be necessary to stabilize climate.[1]

To ignore the **production** side of the electrical supply equation would make no more sense than to certify produce as "organic" if it was harvested from farms that had significantly less than 100% organic growing practices on the rationale that the "non-organic" produce portion of production is the portion that is "lost" in transportation and spoilage. Electrons, like produce, cannot be segregated based on whether they are destined for final consumption or transitional losses.

That the legislature intended zero carbon emissions from the supply **system** serving California retail load, rather than hiding a portion of that system behind a veil, is even more evident in its declaration that the SB 100 mandate shall not allow "resource shuffling" or "increasing emissions elsewhere in the western grid." As commonly understood, resource shuffling is the arbitrary assignment of environmentally damaging resources to a destination other than the one subject to a mandate or voluntary environmental target, thus allowing the economic maintenance or even increase in output from those resources. Assigning fossil-emitting generation to the category of "losses" would have exactly this effect of maintaining or in some cases even increasing carbon emissions relative to the mandated baseline - whether inside or outside of California.

Second, the choice to hide significant carbon emissions as a matter of preferred policy behind the veil of T and D and storage losses is even less justifiable since the cost differential between excluding and including full system emissions is roughly 6% (see presentation slide 24), which is effectively a noise level difference for a 2045 endpoint.

In short, the agencies should not conduct analysis based on an interpretation of the statute that runs contrary to the language and intent of the law, and common sense. SB 100 is not an "approximately 90% solution" for the planet. It was enacted to lead the state and the world to a completely decarbonized electricity system.

2. More centrality should be given to high electrification if not the high hydrogen scenarios.

Given other California policies calling for a complete decarbonization of the state economy by midcentury. Arguably the "high electrification" assumptions should form the basis for both the "core" and " study" scenarios. Especially given the recent emphasis on the need for large quantities of hydrogen to displace unabated fossil fuels in hard to reach sectors such as heavy transport and industry, the high hydrogen scenario should also receive equal treatment as a sensitivity.

3. A wide variety of firm zero carbon resources should be considered and highlighted

The importance of technology inclusivity and optionality – and specially dispatchable zero carbon generation -- in achieving zero carbon power grids affordably has been emphasized in a wealth of literature in recent years. A recent meta-study of 40 deep grid decarbonization studies concluded that retaining firm zero carbon energy – whether nuclear, fossil with complete carbon capture, or firm renewables such as advanced geothermal – is likely to reduce the cost of decarbonization substantially, as compared with relying solely or nearly exclusively

[1] See IPCC, Global Warming of 1.5 Degrees, https://www.ipcc.ch/sr15/

on variable renewable sources such wind, hydroelectric power and solar energy.[2] A typical recent detailed analysis of the role of firm energy in a Northeast and Southern electric system, for example, found a dramatic cost difference between 100% clean electric systems that harness wind, solar, and firm resources and those that rely solely on wind and sun.[3]

While the study does allow "generic dispatchable" resources to play, this option appears only in the second tier of analysis. At the same time, as noted below, several candidate zero carbon dispatchable resources are excluded, while unabated natural gas is allowed in the mix, in effect affirming the importance of zero carbon firm resources to maintain reliability. The ***central*** modeling scenarios should test the impact of allowing a variety of firm zero carbon resources to supply power, as further discussed below, rather than being treated effectively and generically as a sensitivity.

4. Unabated natural gas should be excluded from the "study" scenarios

Even assuming the core scenario is legitimate from a legal and policy perspective, the presentation does not explain why unabated natural gas is allowed to persist in the study scenario (see slide 16) -- which is ostensibly designed to eliminate all carbon emissions from the grid -- rather than being replaced by other zero carbon firm generation. If this decision is based on an assumption or conclusion that the cost associated with replacing unabated gas in total is too high, that cost should be quantified, and the decision defended, especially in light of the points we raise below which suggest that affordable zero carbon firm generation with characteristics of gas CCGT and CTs is highly plausible.

5. The characteristics and costs of assumed "long duration storage" should be spelled out transparently

The model (slide 17) builds what appears to be 2-4 GW of "long duration storage." This resource choice stands out especially because of the report's dismissal of other firm zero carbon technologies as "speculative." The background document provides no information on the characteristics, costs or assumed duration of such storage. CATF's understanding is that the RESOLVE model cannot model storage beyond 24 hours since it uses sample days only and does not link them chronologically. If long duration storage here is euphemism for incremental pumped hydro storage, that should be spelled out; but that would raise the question of why other firm zero technologies were excluded which are not less, and perhaps far more, plausible.

6. Natural Gas with carbon capture (CCS) meets criteria to be included in Core scenarios

The Modeling Framework and Scenarios Overview document states the following criteria for selecting the technologies would be included as candidate resources in modeling the 'core' SB100 scenarios.

"For modeling for the SB 100 Report, staff included candidate generation resources that meet the above criteria and are viable resources in terms of technology readiness, alignment with other state policies and public and environmental health priorities, and resource availability. Only commercialized technologies with vetted and publicly available cost and performance datasets were included for core scenarios."

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[2] Jenkins, Jesse D., Max Luke, and Samuel Thernstrom. "Getting to Zero-carbon Emissions in the Electric Power Sector." *Joule* 2.12 (2018): 2498-2510. (Link here)

[3] Sepulveda, Nestor A., et al. "The role of firm low-carbon electricity resources in deep decarbonization of power generation." *Joule* 2.11 (2018): 2403-2420. ("Across all cases, the least-cost strategy to decarbonize electricity includes one or more firm low-carbon resources. Without these resources, electricity costs rise rapidly as CO_2 limits approach zero. Batteries and demand flexibility do not substitute for firm resources. Improving the capabilities and spurring adoption of firm low-carbon technologies are key research and policy goals.") (Link here).

With these criteria in mind, we believe that NGCC with 100% CCS is eligible and must be a candidate resource in the core scenario.

CCS technology for natural gas fired (NGCC) power plants are commercially available. At least seven natural gas-fired power plants across the country are currently in various stages of CCS development. Four of these plants have received Front-End Engineering & Design (FEED) project grants from the U.S. Department of Energy in 2019, and one of them is right here in California.[4] With their DOE grant, California Resources Corporation (CRC), are currently performing their FEED study to add CCS on their 550 MW Elk Hills NGCC power plant. They are working with commercially available CCS technology provided by Fluor called EFG+.[5] There are other projects that the DOE provided grants to that are also designing their capture projects on NGCC plants. NGCC CCS technology is technically ready for deployment and hence must be considered as meeting the above criteria.

The Modeling Framework & Scenarios Overview document mentions that one of the reasons natural gas with CCS is not a candidate resource in the core scenarios is because it may not result in absolute zero emissions. We believe that NGCC CCS with 100% can be possible and must be included as one of the candidate resources. Even though NGCC with CCS projects under development are likely not looking at 100% capture, there is no technical limit to doing 100% capture using currently available technology if the economics allow for it.[6] According to recent literature review "the 90% capture rate cap as an artificial limit. It is an historical benchmark, originally based on the economics of capture. The review indicated there were no technical barriers to increasing capture rates beyond 90% in the three classic capture routes (post-, pre- and oxyfuel combustion) and with the broad suite of CO2 capture technologies currently available or under development." This means that if 90% capture technology is commercially available then 100% capture on NGCC is also commercially available and 100% NGCC with CCS can be included as a candidate resource in the core scenarios as well.

We request additional Core scenario model runs include NGCC-CCS and that the upcoming draft report includes these results. Across scenarios, the model finds that there is a need for around 35GW of firm capacity in 2045 of which around 25GW is retained unabated gas capacity that will continue to spew CO2 into the atmosphere. We believe that including CCS on gas in the SB100 core scenario may help reduce level of CO2 emissions still remaining in the power sector in 2045 coming this 25 GW of unabated gas capacity that is retained in the grid.

7. Cost assumptions for 'Study: zero carbon firm' scenario

The SB100 Modeling Framework and Scenarios Overview document mentions that generic zero carbon dispatchable resource could represent CCS on NGCC plants or generation using drop-in renewable fuels. We would like to request that in the upcoming Draft Report the Agencies include supporting information for how the cost assumptions we selected. It would be important to know whether 100% carbon capture (as opposed to 90% carbon capture) was assumed on gas power plants to develop this assumption.

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[4] FOA 2058: Front-End Engineering Design (FEED) Studies for Carbon Capture Systems on Coal and Natural Gas Power Plants https://www.energy.gov/fe/foa-2058-front-end-engineering-design-feed-studies-carbon-capture-systems-coal-and-natural-gas
[5] Fluor Awarded Front-End Engineering and Design Contract for California Resources Corporation Carbon Capture Project, July 21, 2020: https://newsroom.fluor.com/news-releases/news-details/2020/Fluor-Awarded-Front-End-Engineering-and-Design-Contract-for-California-Resources-Corporation-Carbon-Capture-Project/default.aspx
[6] IEA-GHG 2019-02 Towards Zero Emissions: https://ieaghg.org/publications/technical-reports/reports-list/9-technical-reports/951-2019-02-towards-zero-emissions

8. Cheaper zero-carbon Hydrogen can be available and included in all scenarios

Hydrogen as a replacement fuel has been excluded from being considered a candidate technology in the core scenario due to inadequate cost data. However, for future scenario runs, we would like to submit cost data that we believe represents a technically feasible hydrogen production option using natural gas and CCS, sometimes called "blue" hydrogen.

An analysis produced for CATF by Hensley Energy Consulting of Laguna Beach, California is **attached** at the end of this letter for reference. Hensley investigated the potential for commercial production of hydrogen from natural gas by auto-thermal reforming (ATR) with 97% carbon capture and determined that the hydrogen cost could be in the range of $11.50 per million Btu gross heating value (MMBtu), depending on project and commodity cost assumptions. This is significantly lower than the near-term hydrogen cost of $28.41 to $47.61 per MMBtu apparently assumed by CEC (albeit after delivery)[7], and at 97% capture the residual CO2 emissions from the ATR hydrogen production process would be significantly lower than often assumed in other studies.

This technology pathway has clear potential to reduce the cost of decarbonizing California's electricity system as well as transportation and industry and should be included in future modeling scenarios.

9. Power Generation with Hydrogen

There is unabated natural gas generation across the scenarios presented, producing between 9 to 24 million tons of CO2. While this may be permissible under some interpretations of the SB 100 mandate, it is important to test the impact and role of low-cost low-carbon hydrogen used as a fuel in further eliminating the CO2 emissions associated with natural gas-fired power generation. CEC has taken one step in this direction by including hydrogen fuel cells for electricity generation in the joint agency analysis but has excluded gas turbines fueled with hydrogen and blends of hydrogen and natural gas. CATF recommends that CEC include gas turbines utilizing hydrogen fuel and blends of natural gas and hydrogen fuel in future analysis, reflecting the following:

- The existing fleet of gas turbines has some capacity to burn hydrogen, although it varies by turbine model. For large utility gas turbines with dry low-NOx combustion technology, typical hydrogen limits are between 5% by volume and 20-30% by volume.[8]
- Significant research and development is underway to increase the hydrogen capability of dry low-NOx combustion systems for gas turbines.[9] The major gas turbine vendors have committed to have new 100% hydrogen-capable gas turbines on the market in Europe by 2030.[10]
- At least one large utility gas turbine project under development to serve California will have a 30% by volume hydrogen capability from day one (2025), and plans to be retrofitted for 100% hydrogen capability by 2045.
- Retrofit of today's state of the art gas turbines to 100% hydrogen-firing are not expected to be excessively costly. The primary changes at the power plant site are expected to be replacement of the core combustion module and modification of instrumentation and fuel delivery systems.[11] Industry analysis indicates that these changes are not expected to have a significant impact on efficiency or capacity.[12] To CATF's knowledge the major turbine vendors have not released cost estimates for these

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[7] SB 100 Joint Agency Report: Charting a path to a 100% Clean Energy Future, Input & Assumptions - CEC SB 100 Joint Agency Report, at 84.
[8] https://www.epri.com/research/products/000000003002017544 at 5
[9] https://www.epri.com/research/products/000000003002017544 at 4
[10] http://s7d2.scene7.com/is/content/Caterpillar/CM20200310-119bf-70120
[11] https://etn.global/wp-content/uploads/2020/01/ETN-Hydrogen-Gas-Turbines-report.pdf at 11
[12] https://etn.global/wp-content/uploads/2020/01/ETN-Hydrogen-Gas-Turbines-report.pdf at 11 and 17

modifications, but an upper bound of 20% of initial combined cycle plant CAPEX has been estimated by some analysts.[13] This value is likely excessive but gives a sense of the magnitude of capital costs that might be incurred.

Based on the above, levelized cost of electricity for a depreciated combined cycle gas turbine power plant retrofit for 100% hydrogen fuel could range from around $75 per MWh to $200 per MWh for delivered hydrogen fuel costs ranging from $10 per MMBtu to $30 per MMBtu.[14]

Conclusion and recommendations

We believe that CCS is an essential tool in the portfolio of climate technologies that California can access to meet the SB100 goals of net-zero power generation by 2045. In the current wildfire season, which has been exacerbated by climate change, we have witnessed the role of firm capacity such as unabated gas meet reliability needs.[15] This makes it all the more critical for California to encourage any firm generation resource to be a zero-carbon technology. We believe there are technology ready and cost-competitive options such as CCS on natural gas and low-cost hydrogen that can serve as a drop-in fuel in existing combined cycle gas turbines.

We recommend that these technologies be included in modeling exercises to determine the various trade-offs and benefits of having a broader portfolio of technologies enabling California to meet SB 100 goals. We would also recommend testing new modeling runs in which these technologies are included and including those results in the upcoming draft report.

Respectfully submitted,
Deepika Nagabhushan
Michael Fowler
Armond Cohen

[See attachment in the next page]

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[13] http://www.element-energy.co.uk/wordpress/wp-content/uploads/2019/11/Element-Energy-Hy-Impact-Series-Study-3-Hydrogen-for-Power-Generation.pdf at 25.

[14] Values included for illustration only, based on EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2020 for new multi-shaft combined cycles, 10-20% of CAPEX applied as hydrogen firing retrofit cost, an annual capacity factor of 30%, and 8% capital recovery factor. More than 80% of estimated LCOE is due to hydrogen fuel cost.

[15] https://www.latimes.com/environment/story/2020-09-01/california-gas-plants-stay-open-time-runs-low-for-climate-action

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MEMORANDUM

TO: Clean Air Task Force

FROM: Hensley Energy Consulting

DATE: September 14, 2020

RE: Estimate of Likely Performance and Cost for Hydrogen Production by Auto-Thermal Reforming of Natural Gas with Very Low CO2 Emissions Based on Literature Review of Recent Project Proposals

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INTRODUCTION:

At the request of CATF, Hensley reviewed selected published studies production of merchant hydrogen for use in industrial, power, transportation, and domestic markets. Throughout the industrialized world natural gas is used now to manufacture hydrogen primarily for use in the petroleum refining and petrochemical industry to produce transport fuels, ammonia, methanol, and other petrochemicals. These technologies can be easily adapted and applied to "fit for purpose" merchant hydrogen production.

Until recently, these NG based hydrogen plants reject the carbon fed to the atmosphere as carbon dioxide (CO2). With growing demands to reduce global warming, there is significant effort by industry and government to produce hydrogen fuels without releasing CO2 to the atmosphere. If such plants are to be constructed to support a new "hydrogen economy", then the captured CO2 must be sequestered or converted to beneficial uses that do not release CO2 to the atmosphere. This memo does not address the sequestration and beneficial uses of captured CO2.

The core technology is steam reforming where methane is reacted with steam to produce carbon monoxide (CO) and hydrogen (H2). The reaction is accelerated using solid catalyst. This process is "endothermic" and substantial heat is required to carry out the chemical transformation of methane (CH4) to H2. Hydrogen atoms in the water (as steam) used for reforming also provides a significant amount of the H2 that is produced as product. Today's reformers supply heat by combusting NG. The steam required for reforming is supplied internally from waste heat recovery.

SMR PROCESS

The steam methane reforming process (SMR) used a fixed bed reactor inside a "furnace" heated by burning NG and byproduct "tail gas". The catalyst forces the reaction to chemical equilibrium. At these conditions, some methane is unavoidably left unreacted in a stream of hot "syngas" (CO and H2). More steam is used to catalytically "shift" the CO to CO_2 and additional H_2 and CO_2 in an exothermic reaction. H_2 is separated from the CO_2 which is typically released to the atmosphere.

Existing plants are optimized for economics, not carbon capture. High Temperature shift is used to convert CO to CO_2 and H_2O to H_2. Only a partial shift is needed to produce H_2, which is separated at high purity from other gases in a pressure swing adsorption (PSA) unit, and large stream of tail gas for heating the reformer. Upstream of the PSA, most of the shifted CO_2 is removed using solvent absorption and released to the atmosphere. Residual CH_4, CO_2, CO and H_2 not captured ends up in the tail gas. This waste gas is burned in the furnace producing more flue gas containing CO_2. This approach has been widely practiced for decades since least cost H_2 was the goal, not lowest carbon emissions.

As concerns over global warming have grown, there have been many efforts to "redesign" the SMR process and optimize for minimum release of CO_2. Many "paper" studies have been published focusing on proven technology. Many companies and government research labs are working on new technology to reduce the combustion of carbon in the system, CO_2 separation technologies, membrane reformers, reactors designed for H_2 rich fuels, electrically heated reformers, and many other ideas. All of these require more laboratory and pilot plant testing before being applied on a commercial scale.

There are two notable projects that retrofitted refinery SMR plants for carbon capture. The Shell Canada "Quest" project and the Air Products SMR Retrofit project at Port Arthur, TX. Each of these projects have extensive reports available to the public.

The "Shell Quest" project in Canada was constructed to retrofit 3 existing SMR plants with carbon capture equipment. Funded by the Canadian and provincial governments, detailed data on the project has been made public. These retrofits were designed to produce CO_2 for sequestration. The project has been operating successfully. The retrofits are designed to process NG and refinery byproduct H_2 mixed gas. An overall capture rate of 60-80% has been achieved because the design criteria did not focus on high carbon capture rates. The project demonstrates that retrofits and reliable operation of carbon capture for SMRs , are all feasible.

The Air Products Port Arthur retrofit of an existing refinery SMR plant has been successful. It focused on demonstrating the Vacuum Pressure Swing Absorption technology. This plant captures about 90% of the CO_2 in the syngas stream but does not capture CO_2 in the reformer flue gas. The overall capture rate is estimated to be approximately 50%. The project also demonstrates the sequestration of CO_2 in oil reservoirs where additional oil can be produced and the CO_2 remains sequestered.

Based on commercially proven technology, our review of the literature and independent analysis indicates that SMR based hydrogen plants can be designed today to capture up to about 50% of the carbon fed to the plant by treating the high pressure syngas stream using proven amine scrubbing technology. If the H_2 rich syngas stream is used for reformer fuel, up to about 60% carbon capture can be achieved and possibly more with some modifications to the furnace design. 90% or more CO_2 can be captured if the reformer flue gas is treated with post combustion amine scrubbing technology, although independent analyses indicate that "post-combustion capture" pathway may be less economical overall .

Some of the many published studies on this topic are listed in the reference list attached to this memo.

ATR PROCESS

Autothermal Reforming (ATR) was developed by the industrial gas industry to improve on the performance and economics of SMR technology. Initially, the focus was on larger scale reactors applied to the manufacture of ammonia and methanol. Several “mega” ammonia and methanol plants have been constructed outside the US where low cost NG is available.

Instead of using an externally fired furnace, the ATR reactor generates heat internally by injecting air or oxygen into the reactor containing catalyst. For ammonia production, air is used to provide the required heat and nitrogen to synthesize ammonia. For methanol, pure oxygen is injected to the reformer reactor to produce syngas in the right mix to synthesize methanol. ATR also operates at higher temperatures. This drives the chemical equilibrium to higher CH_4 conversion, higher yields of product chemicals and reduces the residual CH_4 in the tail gas. This means less CO_2 is produced in the combustion of the tail gas.

Because of the high temperature operations, recovering heat is important to achieving high overall thermal efficiency. That high-level heat is recovered from the hot reformer syngas in the form of steam that is needed to drive the reforming reactions and feed the CO shifting reactions.

Traditional ATR plants, like SMR plants, have a “pre-reformer” which partially converts methane to syngas. The pre-reformer is typically a fired furnace to partially reform before feeding to the primary reformer (SMR or ATR). A fired pre-reformer generates flue gas and works against the goal of high carbon capture.

Most recently, some ATR licensors have developed an ATR process that uses the high temperature syngas product from the ATR reactor to “pre-reform” the feed stream without using a fired pre-reformer. Johnson Matthey has been a leader in the concept of “heat exchange reforming”. Wood Group and other process developers have similar concepts under development. This unfired pre-reformer is referred to as a “reformer heat exchanger” or a “gas heat reactor”. This avoids the use of a gas fired reformer, substantially increases the overall carbon capture rate, and reduces the carbon in the tail gas. The concept has been commercially proven in one ammonia plant and one methanol plant. Two other plants are under development in the US but is not yet sanctioned for construction.

One disadvantage of ATR is the higher power requirements to produce oxygen in an air separation plant. If this power comes from a carbon intensive source, then the higher carbon capture rate of an ATR H_2 plant is partially offset by the CO_2 associated with the higher power requirement. If that power is from a low-carbon power source then this is not an issue.

At this time, a high carbon capture ATR merchant hydrogen plant has not been constructed. The most advanced ATR H_2 plant under development appears to be the HyNet project in the UK. Progressive Energy is developing this project and a UK government funded “pre-FEED” feasibility study has been completed. Progressive Energy has received funding for the detailed FEED which is underway. Some details of the pre-FEED study have been published. The reference list to this memo lists the HyNet project and many other published studies on ATR and comparative studies to SMR.

PRELIMINARY ECONOMICS OF ATR MERCHANT HYDROGEN PRODUCTION

Currently, the HyNet project appears to be the best example of a high carbon capture merchant hydrogen plant using proven commercial technology. The detailed process stream data has not been published. One area of uncertainty is the steam generator combusting H2 rich tail gas. The published reports provide sufficient information to construct overall performance data and preliminary economics. Tables 1 and 2 contain our best efforts analysis of that data.

Table 1 summarizes the performance of the first phase HyNet "LCH" plant using the ATR technology with Reformer Heat Exchanger, based on published data and our analysis. The overall CO2 capture rate for the HyNet project is 97%. Units are provided in English units. At 89.3 million standard cubic feet per day (MMSCFD) H2, this plant is about half the size of the largest single train conventional SMR plant without carbon capture. A single train ATR H2 much larger than the HyNet first of a kind plant could be designed in the future. The reports state that this is their long-term goal.

The steam and power balances were estimated using data from other projects. It is not clear if the steam from the tail gas steam generator is used for power generation or process use. However, the net imported power matches the reported data. Therefore, the data in Table 1 closely match the reported pre-FEED design data.

HyNet reports a summary of the capital cost of the plant at a specific site near an existing refinery. The breakdown of capex includes a large component labeled "air and gas systems". Based on the plant utility data, it appears that the ASU is included in this line item. We converted the capex estimate to US dollars using current exchange rate. No effort was made to convert the estimate to a US Gulf Coast site. In general, open shop construction in the Gulf Coast would be expected to cost less than in the UK. We added to the reported capex (assume to be total installed costs) additional costs for owner's expenses and a contingency of 10%.

Table 2 summarizes a simple "overnight" cost of producing H2 using the performance data from Table 1. This calculation is intended to be illustrative but actual economic conditions for projects on the ground could differ, perhaps substantially. The report projects a plant operating factor of about 95%. For our estimate, we assume a more conservative 90% annual operating factor. Fixed and variable O&M costs were estimated using typical process industry factors. We used a "levelized" weighted average cost of capital of 8%. This rate is reasonable considering the very low long-term cost of debt in today's credit markets.

If we assume this plant is in the US Gulf Coast, today's cost of purchased power may be $25/mwh and cost of natural gas is about $2/MMBTU. The cost to sequester CO2 in that region may be around $10/ton as reported by 2017 DOE study. With those assumptions we estimated "today's over night cost" of H2 would be about $11.49/MMBTU (HHV) or $1.56/kg.

Analysis of Merchant Hydrogen CCS Plant **Table 1**

Performance Data

Cases	Units, Features	Reported or Calculated Data
Location		Gulf Coast USA
SMR Reformer Fuel		None ATR with PreRef HX
Bass: UK Hynet Project	Feed/Fuel	Natural Gas (UK Typical Spec)
	Steam Generator Fuel	Tail Gas Only
	Process Configuration	JM ATR/RHX/Shift/Amine/PSA
	Reformer Oxygen	O2 from ASU
	Scale	One Train
NG Feed	Mmbtu, hhv / hr	1,429.8
NG Heating Value	Btu HHV/scf	1,013.7
NG Feed	MMSCFD	33.8
NG Fuel to burners	Mmbtu, hhv / hr	none
Total NG feed + fuel:	Mmbtu, hhv / hr	1,429.8
H2 Product stream:	MMSCFD	89.63
H2 prod stream Total HHV	MMBTU/hr	1,211.4
	lbs/hr	19,680.9
	kg/hr	8,929.6
	KnM3/hr	100.0
Thermal Efficiency	H2/NG HHV	84.7%
Thermal Efficiency	H2/NG+Power	80.3%
Hydrogen Composition	mol% H2	99.999%
Pressure (w/o compress.)	psig	676
Temperature	deg. F	59
H2 prod stream Heating Value	BTU/SCF HHV	323.8
CO2 Product Stream	sT/hr	82.97
	vol % CO2	99.7%
Pressure	psig	dense phase
Temperature	deg. F	32-67
Carbon Balance		
Carbon in Feed (CO2 basis)	sT/hr	85.56
Carbon in tailgas to steam gen	sT/hr	2.59
CO2 captured	sT/hr	82.97
% CO2 captured	%	97.0%
		0.26
Utilities		
Raw Water, gpm (BFW/CT)	gpm	416
Power:		
Air Separation Unit	KW	5,500
H2 Plant	KW	6,500
Offsites, BOP	KW	4,900
CO2 compressor	KW	6,000
Total kW (net purchased)	KW	22,900

Estimated Required H2 Selling Price (at Plant Gate) **Table 2**

			-
Overnight $2020	UK location US$	$1.23 per UK pound	
Capex, $MM 2018-20 (TIC)	$MM US	$	312.30
Owner's cost thru In Service	$MM US	$	17.70
Contingency, 10%	$MM US	$	33.00
Capex, with Owner's Cost	$MM US	$	363.00
Capex per unit H2 capacity	$MM/MMSCFD	$	4.05
	$/N3/hr	$	3,630
	$/kw	**NA**	
Capacity Factor	planned/forced		90.0%
Commodity Pricing	indicative pricing		
Natural Gas	$/MMBtu HHV	$	2.000
Power	$/kwhr	$	0.250
CO2 Transport, Sequestr.	$/Ston	$	10.000
Annualized Rates			
Natural Gas	MMBtu		11,259,310
Hydrogen	MMBtu		9,539,511
Hydrogen	kg		70,401,286
CO2 captured	short tons		653,390
Purchased Power	kwhr		180,543,600
	% Capex	**$MM/yr**	
Capital Charge	8.00%	$	29.04
Fixed O&M, Labor, Materials	1.50%	$	5.44
Prop Taxes, Insurance, G A	1.50%	$	5.44
Variable Maint, Chems, Cat	0.70%	$	2.29
Purchased Natural Gas		$	20.27
Purchased Power		$	40.62
CO2 Transport, Sequestr.		$	6.53
Total Revenue Requirements		$	109.64
Required H2 Price	$/MMBtu	$	11.49
	$/MSCF	$	3.72
	$/lb	$	0.71
	$/kg	$	1.56

KEY FINDINGS:

- Large scale merchant hydrogen plants can be constructed today using proven commercial technology based on natural gas reforming and gas purification technology.
- Merchant H2 plants designed for minimum carbon intensity can be built today. SMR technology can achieve carbon emission reductions of 80 to 90% or possibly more with carbon reduction design optimization. ATR technology can achieve 95-98% reduction in carbon emission.
- ATR H2 plants have the disadvantage that oxygen is needed to achieve it low carbon intensity goals. Additional power is needed to produce the oxygen. If this power comes from fossil fuel resources, the ATR appears to retain is lower carbon intensity lead over SMR. Green power would avoid this issue.
- Current research and development is underway for both ATR and SMR and associated gas purification technologies can be expected to further reduce the carbon intensity of NG to H2 processes.
- Cost estimates derived from the published data from Progressive Energy for the UK HyNet project indicate the following for an ATR based merchant H2 Plant located in the Gulf States, USA region:
    - Plant capacity is about 89 MMSCFD
    - Carbon Capture is about 97% and Thermal Efficiency is about 85%
    - Purchased power is 22.9 Mw
    - CO2 to sequestration is about 83 short tons/hr
    - Capex with owners' costs is about $363 million.
    - With $2/mmbtu NG, $25/mwh power and $10/sT CO2 sequestration cost, the indicative cost of H2 is about $1.56 per kg or $11.49/MMBtu (HHV) at the plant gate.
- ATR single train plants can be constructed at 2 to 3 times the capacity of the HyNet project. Thus, economies of scale, design optimization, technology improvements are expected to bring down the cost of very low carbon hydrogen.
- The NG reforming and gas purification industry is highly competitive worldwide and actively competing today to bring merchant hydrogen production into widespread use today. Some of the technology suppliers include Linde, Air Products, Air Liquide (Lurgi), Haldor Topsoe, Johnson Matthey, Thyssen Krupp Uhde, UOP, Axens, Fluor, KBR, Foster Wheeler, Wood Group, and many more.
- NG Reforming CCS technology is ready today to bring large scale H2 economy to reality.

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Qualifications and Experience

Dr. Douglas Cortez has over 40 years' experience in the electric power, petroleum refining, petrochemical production, alternative and renewable energy industries. During his career, he has focused on the clean fuels, clean power, and environmentally superior technologies, including low carbon emission technologies. He has held leadership positions with major energy companies with focus on the fields of technology research and development, project development, project financing, and engineering and construction.

Hensley Energy Consulting LLC

In early 2006, he formed Hensley Energy Consulting LLC, an independent technology and management consulting company specializing in providing professional services to clean energy industries, electric and gas utilities, environmental NGO's, financial and government institutions.

He has provided expert public testimony in several power plant licensing, utility rate cases, environmental permit cases and litigation cases.

Fluor Corporation

From 1984 to 2005, he was an executive with Fluor Corporation, the nation's largest publicly held engineering and construction company. At Fluor, he was Vice President, responsible for project development, project finance, and technology development.

In the power sector, he was active in developing, designing and financing a wide range of projects for regulated utility and independent power companies, including low carbon power projects, complex refinery, low carbon natural gas power projects, petrochemical plants and geothermal energy plants.

Tosco Corporation

From 1973 to 1983, he was an executive with Tosco Corporation. He was responsible for developing, financing and constructing clean and efficient cogeneration facilities at Tosco refineries and EOR fields, development of Tosco clean technologies for coal and petroleum coke utilization, development and licensing of Tosco's shale oil production, coal processing and petroleum refining related technologies.

Other Experience

From 1969 to 1973, he was employed by an independent engineering consulting company that specialized in petroleum refining and geothermal energy production. During that period, he developed and constructed geothermal power plants, and petroleum refinery projects.

Employment History

2006- Present	Managing Partner, Hensley Energy Consulting, LLC
1984 - 2005	Vice President, Fluor Enterprises
1973 - 1984	General Manager, Tosco Corporation
1970 – 1973	Project Manager, Ben Holt Company
1969 – 1970	Research Engineer, TRW Systems

Education:

ScD Chemical Engineering, Massachusetts Institute of Technology
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BS Chemical Engineering, University of California, Berkeley

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Industry Participation:

American Institute of Chemical Engineers
Gasification Technologies Council
Coal Utilization Research Council
FutureGen Industrial Alliance – Technical Advisory Committee
Range Fuels – Member, Scientific Advisory Committee

Publications and Public Testimony:

A list of publications and public testimony can be provided upon request.