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Comments of the Clean Air Task Force

Additional submitted attachment is included below.

BEFORE THE CALIFORNIA ENERGY COMMISSION AND THE CALIFORNIA AIR RESOURCES BOARD

DOCKET NO. 19-SB-100

COMMENTS OF THE CLEAN AIR TASK FORCE FOLLOWING THE NOVEMBER 18, 2019 TECHNICAL WORKSHOP

DECEMBER 2, 2019

Thank you for the opportunity to comment on matters addressed in the above-referenced workshop. These comments build upon comments CATF previously submitted in this matter on September 19, 2019.

I. Any analysis of pathways to meet the SB 100 mandate should be based on actual generation needed to meet the zero carbon emission requirement and not ignore unabated CO2 emissions associated with gross generation in excess of delivered retail sales

The clear intent of SB 100 is to achieve a carbon-free electric system serving California load by 2045. Yet materials presented by staff[1] at the above workshop, referring to the RESOLVE model, suggested that SB 100 could be interpreted to allow for uncontrolled fossil generation to supply California's needs:

> "SB 100 requires GHG-free generation to equal electricity retail sales in 2045 and, as modeled in RESOLVE, gas generation is not prohibited for the following reasons:
> – Exported GHG-free power counts towards the SB100 requirement, leaving room for some internal load to be met with GHG-emitting resources
> – Transmission and distribution losses (~8% of demand) are not counted as retail sales, and may be met with GHG-emitting resources"

CATF believes that such an interpretation is flatly contrary to both the letter and spirit of SB 100.

The core requirement of SB 100 reads as follows:

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[1] Jason Ortego, CPUC, "CPUC Integrated Resource Planning: SB 100 Framing Study Scenarios," (Nov. 18, 2019) https://www.energy.ca.gov/event/workshop/2019-11/sb-100-technical-workshop.

> **454.53.** (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.[2] 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 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.

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[2] *See, e.g.,* IPCC "Fifth Assessment Report," (Oct. 2014) https://www.ipcc.ch/assessment-report/ar5/.

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.

II. The agencies should consider multiple options for flexible, load-following generation, and a reasonable range of costs for such resources

As previously stated in CATF's comment in this docket, most analyses suggest that some form of dispatchable, firm zero carbon generation is essential to keep the costs of a zero carbon electricity system affordable.

Between now and 2046, technology will evolve to be both cleaner and cheaper. Electricity production that relies on nuclear power and combustion of fuels are no exception. The report developed by The California Energy Commission (CEC), the California Public Utilities Commission (CPUC), and the California Air Resources Board (CARB) should consider at least these four options:

Natural Gas Combined Cycle (NGCC) plants with Post-Combustion Capture

Low gas prices in North America, dispatchability, and the capability to eliminate CO_2 from gas-fired power plants make NGCC-CCS plants an attractive option for California's electric grid. Post-combustion capture technology for NGCC plants is commercially available today from numerous vendors.

Oxygen-Fired Gas Power Plants

New oxygen-fired technologies are emerging that will be able to provide carbon-free electricity from natural gas without post-combustion capture equipment. These technologies create new option for utilizing low-cost natural gas without CO_2 emissions.

Hydrogen

Hydrogen produced from zero carbon energy sources such as renewable energy, nuclear energy, from the reforming of natural gas combined with carbon capture, and various thermo-chemical hybrid processes, can serve as a zero carbon fuel for firm thermal generation.

Nuclear

Nuclear energy, while currently forbidden by statute from being sited in California, remains an important potential cost-effective firm resource, and should be analyzed on reasonable cost projections, in the agencies' studies.

This section provides more description of the options described above.

Post Combustion Capture on NGCC

These comments focus on one type of post-combustion capture: amine scrubbing. This technology removes CO_2 from flue gas by contacting it in a tower called an absorber. The absorber removes the CO_2 in the flue gas by binding it with amines in an aqueous solution. The cleaned flue gas leaves the absorber and is vented through the plant's stack. The CO_2-rich amine solution is pumped from the absorber to a stripper. Steam in the stripper breaks the CO_2-amine bond, allowing the CO_2 to leave the stripper so that subsequent processing steps can dewater and compress it for transport and injection deep underground. The amine solution, now free of the CO_2, is recycled from the stripper back to the absorber.

Amine scrubbing technology has been commercially available for decades in industrial applications. Several vendors including Linde/BASF, Mitsubishi Heavy Industries (MHI), Cansolv (Shell), and Fluor offer the technology for NGCC plants.

The first NGCC plant to utilize post-combustion amine scrubbing was in Bellingham, Massachusetts. Between 1991 and 2005, the plant captured 330 tonnes per day of CO_2 from a 40 MW slip stream. The CO_2 was sold to a beverage company. The plant closed in 2005 due to rising natural gas prices. In some respects, post-combustion capture from NGCC plants is easier than from coal plants because unlike coal emissions, flue gas from gas plants does not contain sulfur and particulates that can degrade the amine solution. Natural gas emissions from NGCC plants do pose other challenges for capture such as lower CO_2 concentrations and higher oxygen content. During its operation, the Bellingham plant demonstrated that post-combustion capture worked economically on plants with dilute CO_2 flue gas (3 percent CO_2) and relatively high oxygen content (14 percent).[3]

Several factors are driving developer interest in NGCC-CCS applications. Utilities across the nation are pledging to completely decarbonize their electric production by 2050. In 2018, Congress revised 45Q tax incentives to provide up to $50 per tonne of CO_2 permanently stored underground.

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[3] Fluor, "Projects: Northeast Associates Bellingham FPL Facility - CO2 Recovery EPC," https://www.fluor.com/projects/co2-recovery-epc (last visited Dec. 2, 2019); ZeroCO2, "Bellingham," http://www.zeroco2.no/projects/bellingham (last visited Dec. 2, 2019).

In September 2019, U.S. Department of Energy awarded $55.4 million in grants[4] to prepare detailed engineering designs for nine post-combustion power plant projects, including four NGCC applications. These NGCC projects include California Resource Corporation's 550 MW Elk Hills plant in Kern County, an advanced amine (piperazine) design for the Mustang NGCC plant in West Texas, Linde/BASF technology on a Southern Company NGCC plant located either in Mississippi or Alabama, and a Bechtel led-effort to develop an "open source" design for a Texas NGCC plant owned by Panda Energy.[5]

The cost of post-combustion capture depends on the specific NGCC plant. Factors that impact costs include the capacity factor of the plant (the less the plant runs the more expensive the electricity), the cost of natural gas, whether the carbon capture unit is placed on a new or existing plant, the type of storage used (enhanced oil recovery or saline), distance to the storage site, the quantity of CO_2 captured, and the availability of incentives to offset costs. The National Energy Technology Laboratory (NETL) estimates that the 2018 cost of a new NGCC running at 85% capacity factor, with 90% carbon capture utilizing saline storage with moderate transportation costs is $74.40 per MWh. The Clean Air Task Force estimates that 45Q tax credits reduces the electricity cost of capture to around $55 per MWh. For the NGCC plant without capture, NETL estimates that the cost of electricity is $43.30 per MWh.[6] As described later in this document, the costs of CCS on NGCC plants are likely to decrease significantly over time due to innovation.

One of the advantages of NGCC-CCS plants is the ability to back-up renewables with low-carbon or carbon-free emissions. One design study for an NGCC-CCS plant in Scotland estimated the plant could ramp at 88MW/minute in the range of 60% -100% capacity factor.[7] NGCC-CCS developers in the United States are also exploring the option of providing steam and/or electricity to the post-combustion capture unit with a separate natural-gas fired auxiliary boiler or cogen plant. This design option, used at Petra Nova's Parish coal plant CCS project, has the potential to allow greater flexibility in NGCC plant operation, including ramping.

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[4] DOE, "U.S. Department of Energy Announces $110M for Carbon Capture, Utilization, and Storage," (Sept. 13, 2019), https://www.energy.gov/articles/us-department-energy-announces-110m-carbon-capture-utilization-and-storage.

[5] DOE, "FOA 2058: Front- End Engineering Design (FEED) Studies for Carbon Capture Systems on Coal and Natural Gas Power Plants," (Sept. 23, 2019), https://www.energy.gov/fe/foa-2058-front-end-engineering-design-feed-studies-carbon-capture-systems-coal-and-natural-gas.

[6] DOE, NETL, "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity," at 11 (Sept. 24, 2019) https://netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVol1BitumCoalAndNGtoElectBBRRev4-1_092419.pdf.

[7] Summit Power Caledonia UK Ltd, "Caledonia Clean Energy Project: Feasibility Study Phase 2, Final Report, Summary Version," at 17 (May 2018) https://summitpower.com/wp-content/uploads/2018/06/CCEP-Feasibilility-Final-Report-MAY-2018-SUMMARY-VERSION.pdf.

While capture rates for NGCC-CCS plants are typically described as 90% capture,[8] higher levels of capture can be achieved. For example, the engineering design studies DOE funded for coal plants in September of this year include designs for 95% capture.[9] There is no technical reason why capture rates for NGCC-CCS plants can't approach 100%. As described later in these comments, CATF recommends that California policy allow zero-carbon CCS projects in the state to pursue operational plans that start at lower levels of capture and gradually increase to the required 100% decarbonization by 2045 . CATF also recommends that for NGCC-CCS plants to be considered eligible zero-carbon resources, California regulators will have to require a life cycle GHG accounting of the natural gas and require stringent limits on GHG emissions from the oil and natural gas sector through regulation or procurement specification. .

Besides amine scrubbing systems, other approaches exist for post-combustion capture which are in varying stages of development and commercialization. They include membranes that rely on pressure changes to remove CO_2, solid sorbents that remove CO_2 by adsorbing it to the surface of a structure, and cryogenic separation methods that rely on special CO_2 phase change properties that occur at low temperatures. Among the design awards by DOE this September was funding for engineering studies for Membrane Technology and Research Inc., a California-based company that will evaluate their membrane technology for Basin Electric's Dry Fork coal plant.[10] Svante (formerly known as Inventys) uses a solid sorbent in a rotating adsorption machine (RAM) that significantly reduces capital costs of post-combustion capture. The company has a 30 tonne per day pilot plant at the Husky Energy's oil field in Lloydminster Saskatchewan.[11] Sustainable Energy Solutions (SES) innovation is in early development stages of cryogenic carbon capture. The company believes that their technology has the potential to cost half as much as conventional systems and capture 95%-99% of CO2 emissions from fossil fuels.[12]

Oxygen-Fired Systems

Conventional power plants combust fuels in the presence of air. Air dilutes the flue gas with nitrogen, making CO_2 capture more expensive. By separating the nitrogen from the air prior to

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[8] DOE, NETL, "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity," at 11 (Sept. 24, 2019) https://netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVol1BitumCoalAndNGtoElectBBRRev4-1_092419.pdf.

[9] DOE, "FOA 2058: Front- End Engineering Design (FEED) Studies for Carbon Capture Systems on Coal and Natural Gas Power Plants," (Sept. 23, 2019), https://www.energy.gov/fe/foa-2058-front-end-engineering-design-feed-studies-carbon-capture-systems-coal-and-natural-gas.

[10] *Id.*

[11] Svante, "Keeping CO2 Out of the Air: Market Read, Commercial-Scale Net-Zero Emissions," https://svanteinc.com/solutions/ (last visited Dec. 2, 2019).

[12] SES Innovation, "Sustainable Energy Solution," https://sesinnovation.com.

combustion, oxygen-fired power plants simplify CO_2 capture step. One oxygen-fired example is Net Power.

Net Power is demonstrating a high-pressure, oxygen-fired 50 MW_{th} natural gas power plant in Texas that the company states will be emissions-free. Highly pressurized natural gas, oxygen and recycled CO_2 (used to control combustion temperature) enter a combustor. The hot, high-pressure gas leaving the combustor expands through a turbine to generate electricity. The gas leaving the turbine contains CO_2 and water. Water is removed, and the CO_2 is recompressed. Some of the CO_2 is exported for geologic storage and the remainder is heated and recycled back to the combustor. The system takes advantage of the unique physical characteristics of supercritical carbon dioxide that are achieved in the Net Power temperature and pressure operating conditions. These conditions enable the gas turbine to be less than one tenth the size of a similar-capacity steam turbine.[13]

Net Power discussed the costs of its system at GHGT-14 held Australia in 2018. As benchmarks, Net Power estimated today's NGCC plant using amine scrubbing post-combustion capture and selling CO_2 for EOR in combination with $45Q tax credits can produce electricity at $64 per MWh. Without capture, Net Power estimated the costs of electricity from an NGCC plant to be between $44/MWh and $49/MWh depending on the class of turbine. Against these two capture and no-capture benchmarks, Net Power estimated that with 45Q tax incentives and learning-by-doing, the 30th Net Power plant will produce electricity at a cost of $19/MWh. Without 45Q, the cost of electricity of Net Power would be comparable to an uncontrolled NGCC plant.[14]

Hydrogen as a firm zero carbon fuel

Hydrogen, and anhydrous ammonia (as a hydrogen carrier), have the potential to help solve one of the most difficult decarbonization challenges in California – "zero-emission load balancing" (ZELB) on the electric grid – as well as playing a potentially significant role in decarbonizing other aspects of California's economy including ports, shipping, and heavy trucking, and other transportation. Unfortunately, the pathways, technical feasibility, and economics of storing, delivering, and using hydrogen for ZELB in existing and new combined cycle gas turbine (CCGT) power plants in California is likely to be a complicated region- or case-specific analysis informed by incomplete information, at least for the time being. Ongoing research by many parties suggests that a gradual transition from natural gas to hydrogen in CCGT may be possible, however.

The following five points are particularly relevant:

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13 Net Power, "NET Power and Oxy Low Carbon Ventures Announce Investment Agreement to Advance Innovative Low-Carbon Technology," (Nov. 8, 2018), https://www.prnewswire.com/news-releases/net-power-and-oxy-low-carbon-ventures-announce-investment-agreement-to-advance-innovative-low-carbon-technology-300746197.html.

14 Bill Brown, "Demonstration and Commercialization of Net Power and Beyond," GHGT-14 (Oct. 2018) (photos of slide available on file with CATF).

First, blending hydrogen into existing natural gas distribution systems might provide a relatively near-term way to deliver hydrogen to CCGT (as well as other end-users). The literature indicates that hydrogen blending up to 15-20% may be feasible in some areas with limited infrastructure modifications.

- According to NREL: "If implemented with relatively low concentrations, less than 5%–15% hydrogen by volume … appears to be viable without significantly increasing risks associated with utilization of the gas blend in end-use devices (such as household appliances), overall public safety, or the durability and integrity of the existing natural gas pipeline network."
- According to research summarized by PG&E: "Up to 30% by volume hydrogen could be added to the natural gas within the current gas infrastructure without adversely affecting the risk to the public significantly and without any additional mitigation measures."[15] (Although PG&E cites several examples with lower limiting values of hydrogen concentration).

Obviously, before undertaking any physical work these issues would need to be studied in detail for the subject natural gas system, with an emphasis on safety.

Second, major equipment vendors have indicated that up to 50% hydrogen blending by volume in the fuel to some of their existing large gas turbines might be tolerable in some cases without changing combustors and with only limited changes to other turbine systems.

- GE has stated: "Results of preliminary testing indicated that this [DLN 2.6e combustion system, which is available on the 9HA gas turbine] combustion system has entitlement to operate on fuels containing up to 50% (by volume) hydrogen, " while "The DLE combustor, which is found on GE's Aeroderivative gas turbines, is limited to 5% (by volume) hydrogen." "The DLN1 combustion system, which is available on GE's 6B, 7E, and 9E gas turbines, is capable of operating with up to 33% (by volume) hydrogen when blended with natural gas. GE's DLN 2.6+ combustors are capable of operating on hydrogen levels as high as ~15%."[16]
- Siemens has indicated that their existing large gas turbines with DLE combustor technology generally are capable of firing natural gas with hydrogen concentration up to 30% by volume.[17]

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[15] PG&E, "Hydrogen Technical Analysis," (July 3, 2018), https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/interconnection-renewables/interconnections-renewables/Hydrogen_TechnicalAnalysis.pdf.

[16] GE Power, "Power to Gas: Hydrogen for Power Generation," (Feb. 2019), https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel-flexibility/GEA33861%20Power%20to%20Gas%20-%20Hydrogen%20for%20Power%20Generation.pdf.

[17] Siemens, "Power-to-X: The crucial business on the way to a carbon-free world," https://new.siemens.com/global/en/products/energy/technical-papers/download-power-to-x.html.

- Mitsubishi Heavy Industries has stated: "In the case of a 20% hydrogen fuel mix, the existing gas turbine can be used"[18] and has successfully tested a modification to their conventional DLN combustor that would increase the limit to 30% hydrogen.[19]

The major gas turbine manufacturers have also indicated that higher levels of hydrogen (higher than 90% in some cases) have been used on gas turbines with more tolerant combustors (generally in smaller industrial power generation equipment with lower efficiency and/or higher-NOx allowances than large utility systems).

Third, the use of fuel with very high hydrogen fractions (up to 100% of heat input) while maintaining acceptable efficiency and NOx emissions are generally expected to require use of turbine burner systems more advanced than those typically installed on large gas turbines today. The major vendors have committed that these burner systems should be commercially available by 2030 or before, at least in Europe, and should be retrofittable to existing turbines in many cases.[20]

- According to MHI, a dry multi-cluster combustor capable of firing 100% hydrogen is under development with a target completion date of 2024,[21] although Turbomachinery International indicates that for MHI "the attainment of a combustor running in a gas turbine at 100% hydrogen is not targeted for commercial operation until 2030".[22] Furthermore, MHI indicates that some form of full-hydrogen combustor will be retrofittable across its gas turbine fleet, stating that "hydrogen-burning combustor technology can be retrofitted on all MHPS turbines currently operating today, when coupled with hydrogen fuel deliverable modifications" and "Minimal modifications to current MHPS turbines functioning today will make them a future-proof investment".[23]
- Statements from GE with commitments to a full hydrogen-firing availability timeline beyond the European 2030 statement do not seem to be available, but an analysis by Hydrogen Energy International in 2009 determined at that time that "commercial guarantees for F class turbines operating on high hydrogen fuels would be likely" and elected to pursue further

18 Mitsubishi Hitachi Power Systems, "Hydrogen Power Generation Handbook," https://www.mhps.com/catalogue/pdf/mhps_hydrogen_en.pdf.

19 Mitsubishi Hitachi Power Systems, "H2 Gas Turbine for Hydrogen Society," (Apr. 24, 2019) https://www.eu-japan.eu/sites/default/files/imce/eu_jp_energy_business_seminar_mhps_r1.pdf.

20 EUTurbines, "About Us," https://powertheeu.eu/about-us/ (last visited Dec. 2, 2019).

21 Mitsubishi Hitachi Power Systems, "H2 Gas Turbine for Hydrogen Society," (Apr. 24, 2019) https://www.eu-japan.eu/sites/default/files/imce/eu_jp_energy_business_seminar_mhps_r1.pdf.

22 Drew Robb, "Fuel Switching," Turbomachinery International, (Sept. 5, 2018) https://www.turbomachinerymag.com/fuel-switching/.

23 Don Daniels, "Decarbonizng the Power Sector with Renewable Gas," (Sept. 3, 2019) https://www.powermag.com/decarbonizing-the-power-sector-with-renewable-gas/.

studies based on the GE 7FB turbine, suggesting that appropriate technology for large GE turbines is not far off.[24]

- According to Siemens: "By 2030, Siemens gas turbines will be able – or can be retrofitted – to run fully on H_2."[25]

Fourth, the supply of large volumes of hydrogen to California CCGT by 2046 is likely to require construction of new hydrogen infrastructure. For long-distance transportation of hydrogen as hydrogen, pipelines are likely to be the most availing pathway. According to the Roads2Hy analysis in Europe: "Distribution of Hydrogen as a compressed gas remains favoured up to 200-300km while demands are low; higher distances or demands favour liquefaction, with its more Hydrogen-dense transportation justifying the extra fiscal and energy cost of liquefying the Hydrogen. Further increases in sustained demand could lead to commitment to invest in pipeline infrastructure, particularly to major centres of usage."[26] Large-volume sub-surface storage of hydrogen to provide surge capacity may be feasible as well, although this is likely to be highly dependent on available geological resources. In Beaumont, Texas Air Liquide operates a hydrogen storage cavern 1500 meters deep and 70 meters in diameter, holding a month of steam methane reformer production.[27] Additional hydrogen storage opportunities are being explored in Utah.[28]

Fifth, an alternative approach to transporting and storing hydrogen as hydrogen is transporting and storing hydrogen as ammonia, followed by conversion back to hydrogen prior to use. Due to pipeline challenges, using ammonia as a hydrogen medium is under serious consideration in Japan, and may be a useful strategy in other regions including California, the East Coast of the United States, and elsewhere. The approach in Japan envisions converting ammonia back to hydrogen just upstream from the CCGT, using heat recovered from turbine exhaust to drive the ammonia cracking reactions:

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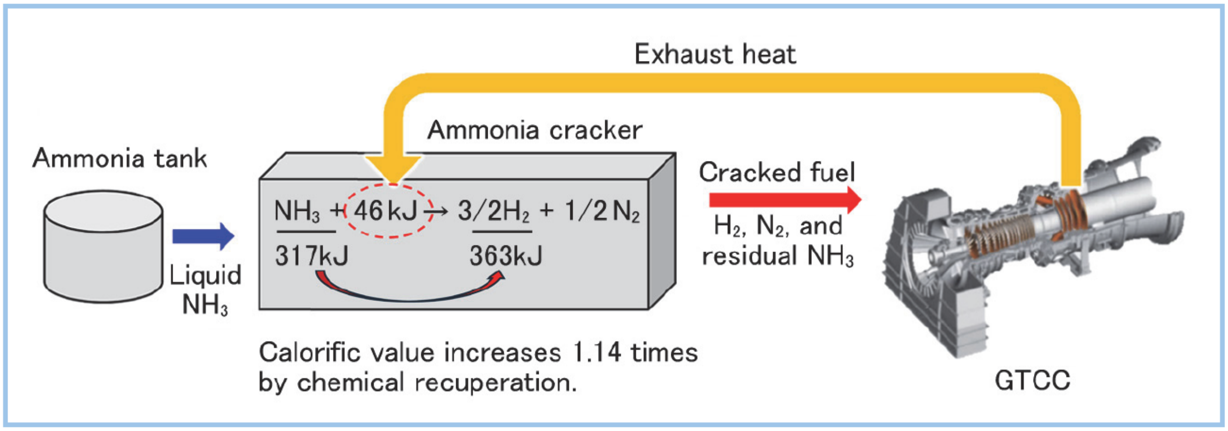
24 HEI, "HECA Feasibility Study, Report #2 – Power Block Gas Turbine Selection," (May 29, 2009).

25 Siemens, "Committed to H2," https://new.siemens.com/global/en/company/stories/energy/hydrogen-capable-gas-turbine.html (last visited Dex. 2, 2019).

26 Aude Cuni, *et al.*, Roads2Hy, "Linking Distributed European Hydrogen Production Sources," (June 19, 2008), https://www.researchgate.net/publication/268426090_Linking_Distributed_European_Hydrogen_Production_Sources_PART_I_Distribution_Issues/

27 Air Liquide, "USA: Air Liquide operates the world's largest hydrogen storage facility," (Jan. 3, 2017), https://www.airliquide.com/media/usa-air-liquide-operates-world-largest-hydrogen-storage-facility.

28 Sonal Patel, "MHPS, Magnum Will Build 1-GW Renewable Energy Storage Facility in Utah," Power (May 30, 2019) https://www.powermag.com/mhps-magnum-to-build-1-gw-renewable-energy-storage-facility-in-utah/.



Developers of this technology in Japan state that "this system can be characteristically applied to high-efficiency and large-capacity GTCC systems with a relatively small number of modifications" and "since the heat necessary for the ammonia decomposition reaction is used for increasing the heat value of hydrogen produced (chemical recuperation), there is no theoretical efficiency drop". Depending on the size of the ammonia tanks used, the total energy storage potential of such a system could be large. The two largest refrigerated ammonia tanks in the world are in Qatar, containing 50,000 metric tons of ammonia each.[29] This represents enough fuel for approximately 2 weeks in a 1000 MWe high-efficiency CCGT.[30]

CATF understands that developing appropriate technical and cost information for these pathways may be time consuming for California energy planners. However, the benefits of this decarbonization planning could be significant, especially when synergies with other sectors such as transportation are considered.

Zero-carbon hydrogen can be produced (1) through the application of full carbon capture and sequestration to steam reformation processes along with technologies and practices that achieve near-zero emissions of methane and other greenhouse gases from natural gas production and transport,[31] and (2) through processes that use zero-carbon electricity to power the electrolytic decomposition of water.

The cost of making hydrogen from processes that combine steam methane reforming (SMR) with full carbon capture and sequestration—often referred to as "blue hydrogen"—is fairly well characterized. According to the IEA, the current of producing hydrogen via steam methane reforming with CCS in the United States in 2018 is approximately \$1.50/kg H_2.[32]

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[29] Oil and Gas Advancement, "QAFCO Ammonia Storage Tanks," https://www.oilandgasadvancement.com/projects/qafco-ammonia-storage-tanks/ (last visited Dec. 2, 2019).

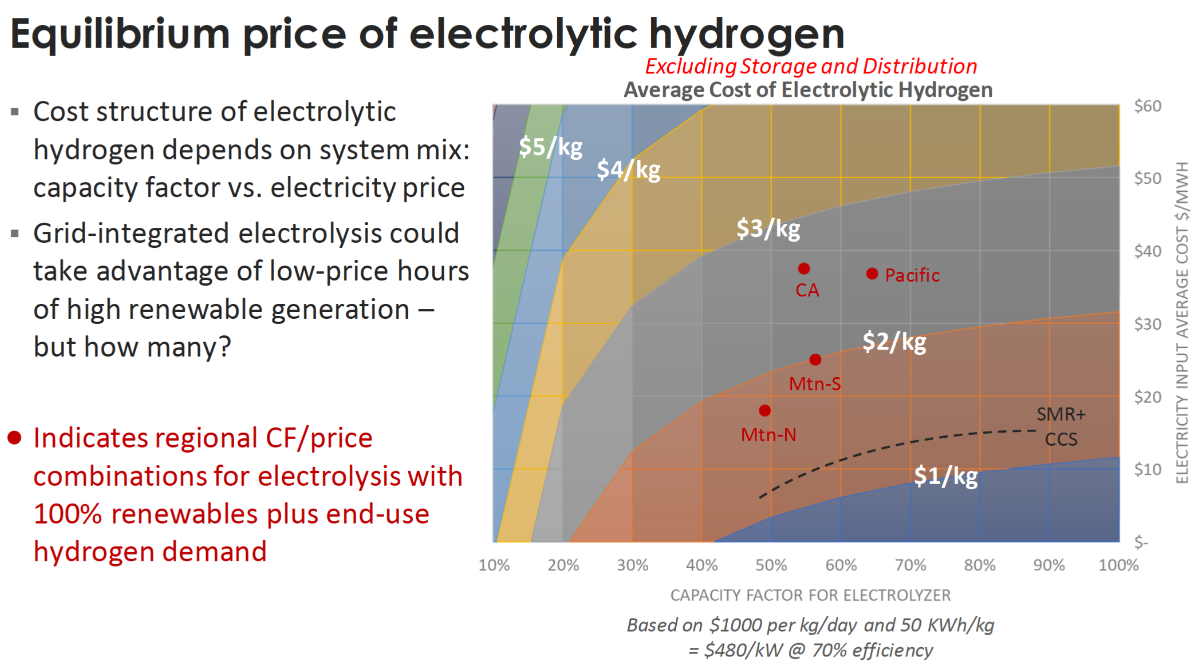
[30] Calculation by CATF assuming ammonia at 0.214 MMBtu-HHV/kg and combined cycle heat rate of 6.2 MMBtu-HHV/MWh.

[31] If natural gas is used as a feedstock for hydrogen production, California regulators should require lifecycle GHG accounting and insist on ultra-tight GHG performance through regulation or procurement specification.

[32] IEA, "The Future of Hydrogen" at 42 (2019) https://www.iea.org/hydrogen2019/.

The cost of producing hydrogen through electrolytic processes that use zero-carbon electricity—often referred to as "green hydrogen"—are more uncertain. Key factors include the evolving cost and performance of electrolyzers, the cost of zero-carbon electricity, and the overall capacity factor of the system. The latter factors can be negatively correlated: the use of inexpensive "surplus" electricity from variable renewable generators or nuclear power plants to power an electrolyzer could reduce operating costs, but doing so could simultaneously reduce the capacity factor of the electrolyzer thus increasing the cost of producing a unit of hydrogen. IEA estimates the cost of producing hydrogen via electrolysis with renewable energy in the United States might decrease to approximately \$2-3/kg H_2 over the long term.[33]

The Electric Power Research Institute (EPRI) estimated the cost of hydrogen made from electrolysis with renewable energy under different capacity factors for the electrolyzer, and charted those costs against its estimated costs for hydrogen derived from SMR with CCS:



Per EPRI's analysis, the cost of producing electrolytic hydrogen in California with a 50-60% capacity factor would be between \$2.50 and \$3.00/kg H_2.[34]

33 *Id.* at 49.

34 Geoffrey J. Blanchard, "Economics of High Renewable Penetration and the Role of Hydrogen: US-REGEN Modeling Analysis," (Oct. 17, 2019) (on file with CATF).

Nuclear Energy

While currently new nuclear plants cannot be sited in California, since no federal waste solution has been opened, nuclear energy generated outside of California, such as the advanced NuScale modular reactor being developed in Idaho,[35] could qualify under SB 100.

CATF urges the agencies to examine and model a reasonable range of assumptions for advanced nuclear plants. Recent analysis suggests that the recent experience with high cost new nuclear electricity plants need not persist, especially if we can return to standardized designs, scale production, and conscious cost control efforts.[36] One such recent report[37] suggests that overnight capital costs of $4,000 or less should be readily obtainable without technology change, simply by adopting, or re-adopting, scale, standardization and cost control approaches used widely throughout the world.

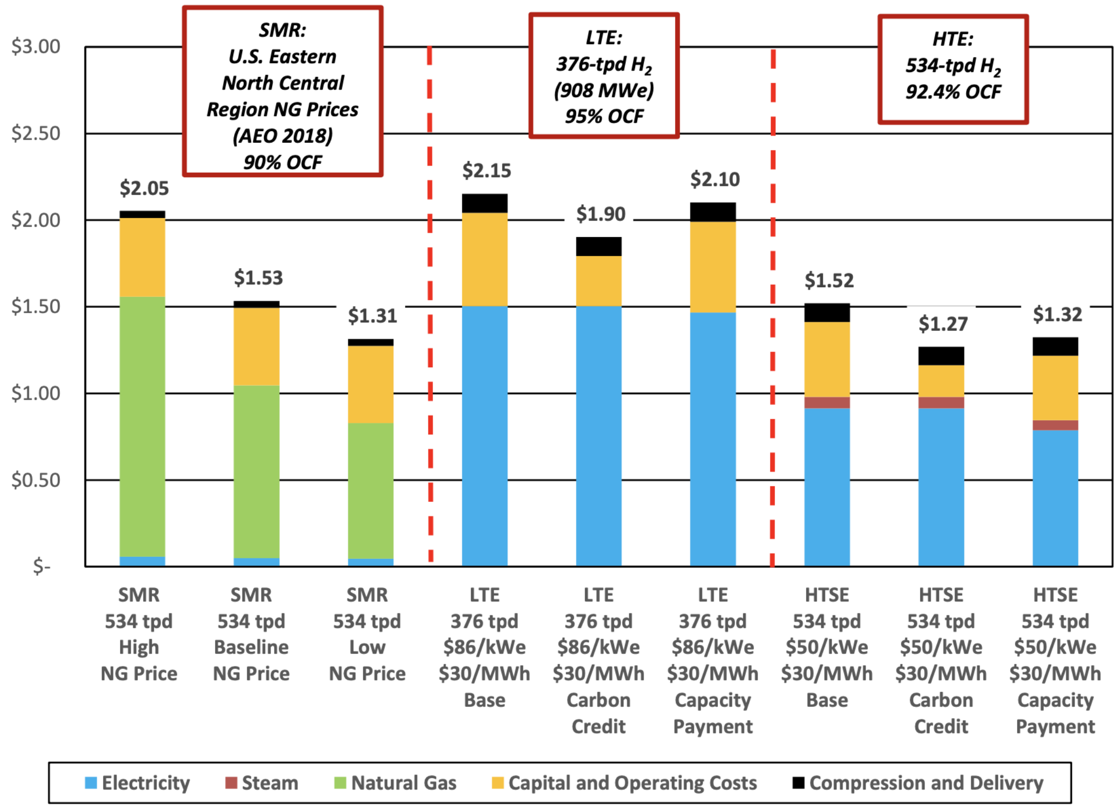
Nuclear energy, including the existing Diablo Canyon units, could also be viewed as a potential source for hydrogen to provide load balancing electricity units. A recent evaluation by the Idaho National Laboratory,[38] suggests that even existing light water technology combined with electrolysis could yield hydrogen at a price competitive with the current lowest cost source – steam methane reforming:

[35] "NuScale reactors clear regulatory review phase," Post Register (July 22, 2019) https://www.postregister.com/news/government/nuscale-reactors-clear-regulatory-review-phase/article_c8b7286b-3569-59de-a584-ed6d92bd8027.html.

[36] *See, e.g.,* Jessica R. Lovering, et al., "Historical construction costs of global nuclear power reactors." 91 Energy Policy 371-382 (2016); and Energy Technologies Institute, "The Nuclear Cost Drivers Project: Report Summary," (April 2018), https://www.eti.co.uk/library/the-eti-nuclear-cost-drivers-project-summary-report

[37] ETI Report *supra* note 36.

[38] DOE, "Light Water Reactor Sustainability Program: Evaluation of Non-electric Market Options for a Light-water Reactor in the Midwest," (Aug. 2019), https://inldigitallibrary.inl.gov/sites/sti/sti/Sort_19807.pdf.



III. III. The analysis should consider technologies which may need a glidepath to zero emissions.

The agencies' report and modeling should allow combustion sources to follow glide path that reaches zero emissions by 2046. It should not constrain options to be zero when they first open.

Post-combustion capture can start and 90% or 95% capture today as first steps toward a 100% capture requirement. Allowing sources to increase capture over time reduces technical and financial risks that might prevent power plants from beginning to capture CO2 now.

Similarly, as noted above, turbines can run on blends of hydrogen as first steps toward 100% hydrogen.

IV. IV. The analysis should consider synergies with other sectors

By Executive Order, California also anticipates decarbonizing the industrial sector by 2045. CCS and hydrogen are essential for decarbonizing industry. The report and the modeling need to reflect the cost and development synergies with the power sector when CCS and hydrogen are used in the industrial sector. For refineries, cement, fertilizer and steel production, CCS is needed to capture CO2 released from the chemical reactions that turn raw materials into finished goods. These industrial applications will require CO2 pipelines and storage sites.

The 2021 report and modeling that supports its conclusions must account for the economies that arise when power and the industrial sector utilize hydrogen and CCS.

V. V. Several aspects of cost and infrastructure need to be carefully addressed in the 2021 report and modeling.

Prices seen by electric consumers need to reflect incentives such as the 26 U.S.C. 45Q tax credit for CCS. 45Q provides up to $50 per tonne of CO2 stored in saline formations and $35/tonne for EOR. To be eligible, projects must commence construction by January 1, 2024. Projects can receive these credits for 12 years.

In addition, modeled costs for future CCS and hydrogen should reflect potential declines from technology innovation. Costs reflected in current DOE-funded projects will fall significantly as second, third and fourth generation carbon capture technologies emerge. Modeling used to support the 2021 report must reflect these cost reductions and performance improvements.

Modeling is likely to assume that CO2 and H2 pipelines will exist in time. While this assumption simplifies modeling, it ignores real-world uncertainty. These uncertainties can be addressed proactively through policy that drive needed infrastructure. While infrastructure is not the focus of these comments, CATF intends to address these issues during the infrastructure workshop that CARB will be holding later in 2020.

VI. The Role of Hydrogen Combustion in Different Resource Scenarios Must Be Clarified

In a November 18, 2019 presentation for discussion purposes titled *Options for Defining Eligible Electricity Resources under SB 100*, Ryan Schauland of CARB outlined two possible interpretations of "zero carbon resources."[39]

The first "resource scenario" (Option 1) would count the following as eligible resource types: current RPS-eligible resource types; large hydroelectric; nuclear generation; and "natural gas generation with CCS where GHG emissions=0."[40] The second "resource scenario" (Option 2) would be the "*same as* Option 1 except [it] would not allow for resources that combust fuel." As

[39] Ryan Schauland, CARB, "Options for Defining Eligible Electricity Resources under SB 100," (Nov. 18, 2019) https://efiling.energy.ca.gov/GetDocument.aspx?tn=230768.
[40] *Id.* at slide 4.

such, it would exclude biomass or biomethane combustion, "natural gas-fired generation with CCS where GHGs=0," and "natural gas combusted at a (currently) RPS-eligible resource (e.g., solar-thermal facilities)."[41]

Per Schauland's presentation, Option 2 would cover both biomethane reformation and natural gas reformation (provided the latter captures and sequesters 100% of its GHG emissions). Because Option 2 is described in the presentation as being a subset of Option 1,[42] it follows that the reformation technologies noted in Option 2 would also qualify under the more expansive Option 1. Accordingly—and appropriately, from CATF's perspective—electricity generated at a hydrogen-fueled turbine would qualify as "electricity … from eligible … zero-carbon resources" per SB 100 under Option 1.[43]

It is less clear whether electricity generated by a hydrogen-fueled turbine would be similarly eligible under Option 2, though, because Option 2 "would not allow for resources that combust fuel." Combusting hydrogen in a turbine is currently the most reliable and most cost-effective method for converting significant volumes of hydrogen to electricity. Having appropriately identified zero-carbon hydrogen as an eligible resource, it seems unlikely that the agencies would want to foreclose the most effective method of converting that hydrogen into zero-carbon electricity.

CATF recommends that the agencies clarify, first, that hydrogen produced from "biomethane reformation" or "natural gas reformation with CCS where GHGs=0" would qualify as an eligible zero-carbon resource under both Option 1 and Option 2 and, second, that the electricity generated when that hydrogen is combusted in a turbine would qualify under either resource scenario as "electricity from eligible zero-carbon resources" per SB 100.

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[41] *Id.* at slide 5.

[42] *Id.* ("Same as Option 1 except would not allow for resources that combust fuel")

[43] *See id.* at slide 2.