

<b>DOCKETED</b>	
<b>Docket Number:</b>	23-SB-100
<b>Project Title:</b>	SB 100 Joint Agency Report
<b>TN #:</b>	269292
<b>Document Title:</b>	Sierra Club, CBE, CEJA, and Earthjustice Comments on SB 100 Draft Results Workshop
<b>Description:</b>	N/A
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<b>Organization:</b>	Sierra Club, Earthjustice, Communities for a Better Environment, and California Environmental Justice Alliance
<b>Submitter Role:</b>	Intervenor
<b>Submission Date:</b>	3/20/2026 4:52:20 PM
<b>Docketed Date:</b>	3/20/2026



March 20, 2026

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California Air Resources Board  
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*Submitted online via comment submittal portal*

**RE: Sierra Club, Communities for a Better Environment, California Environmental Justice Alliance, and Earthjustice Comments on SB 100 Draft Results Workshop**

Dear Commissioners and Board Members,

On behalf of Sierra Club, Earthjustice, Communities for a Better Environment (“CBE”), and California Environmental Justice Alliance (“CEJA”) and our more than half a million members and supporters statewide, thank you for the opportunity to comment on the Senate Bill (“SB”) 100 Draft Results Workshop authored by the California Energy Commission (“CEC”), the California Public Utilities Commission, and the California Air Resources Board (collectively “the Joint Agencies”). We continue to support California’s policy to achieve a 100% renewable

and zero-carbon electricity sector by 2045<sup>1</sup> or earlier and to support resource planning that will lead to substantial reductions in the need for nonpreferred resources in local capacity areas by 2035.<sup>2</sup>

The SB 100 Draft Results Workshop reflects California’s continuing leadership in catalyzing the transition to clean energy, but additional revisions must be made in the final report to ensure full consistency with the letter and intent of this key law, full consistency with other California environmental and public health laws, and to avoid prolonging the public health and climate harms of fossil-fueled power.

We recommend that the Joint Agencies take the following steps to improve the final modeling results for the SB 100 report:

- Publish a draft version of the SB 100 Report and allow stakeholders to provide comment before it is finalized to maintain the integrity of the public process;
- Update the Combustion Resource Retirement Scenario to include avoided gas infrastructure and reliability costs to better reflect reality and analyze offshore wind potential to evaluate scenario tradeoffs;
- Exclude CCS resources from the definition of zero-carbon resources;
- Revise the High Hydrogen-Demand Sensitivity to incorporate realistic assumptions on load shape and flexibility;
- Update the geothermal cost data to reflect the best available data;
- Correct the flawed assumption that federal hydrogen subsidies continue to 2045; and
- Exclude storage and line losses from the interpretation of “retail sales.”

**I. THE JOINT AGENCIES MUST PUBLISH A DRAFT REPORT FOR PUBLIC COMMENT TO MAINTAIN THE INTEGRITY OF THIS PUBLIC PROCESS.**

We appreciate that the Joint Agencies extended the comment period on the Joint Workshop in response to Sierra Club’s request and released modeling data in response to the Joint Organization Request of Sierra Club, CEJA, Communities for a Better Environment, Defenders of Wildlife, and others.<sup>3</sup>

The same Joint Organizations Request letter also detailed the need for the Joint Agencies to release and allow written comment on the Draft Report, and we reiterate that request here. State

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<sup>1</sup> Cal. Pub. Util. Code § 454.53.

<sup>2</sup> Cal. Pub. Util. Code § 454.57(e)(4)(A).

<sup>3</sup> Docket 23-SB-100, *Joint Organization Requests for 2025 SB 100 Report Process and Two Week Extension for Draft Results Workshop Comment Deadline* (Mar. 3, 2026), available at <https://efiling.energy.ca.gov/GetDocument.aspx?tn=268917&DocumentContentId=106109>.

law requires that the SB 100 report be part of a public process,<sup>4</sup> and this 2025 cycle has fallen far short of that standard. At the February 19th workshop, CEC staff announced that this comment opportunity was the one and only comment opportunity before the 2025 SB 100 Report goes to the Joint Agencies for final approval. A single workshop with late released data and no opportunity to review a draft report is not a lawful public process. This issue can and must be rectified. We urge the Joint Agencies to release the modeling data immediately and provide the public meaningful opportunity to review and comment on a draft report before it is finalized.

**II. THE COMBUSTION RESOURCE RETIREMENT SCENARIO COMPLIES WITH STATE ENVIRONMENTAL AND PUBLIC HEALTH POLICIES AND DEMONSTRATES CRITICAL EXTERNAL BENEFITS TO AVOIDING COMBUSTION, BUT ITS COSTS ARE OVERSTATED.**

**A. The Combustion Resource Retirement Scenario Is The Only Modeled Scenario That Is Consistent with California’s Clean Air Act Obligations and Public Health Policies.**

California’s air regulators have acknowledged that meeting health-based air quality standards will require a widespread transition to zero-emission equipment for both stationary sources of all sizes in California’s most polluted air basins. Specifically, the South Coast Air Quality Management District concluded that “there is no viable pathway to achieve the needed reductions without widespread adoption of zero emissions (“ZE”) technologies across all mobile sectors and stationary sources, large and small.”<sup>5</sup>

The steady reliance on gas-fired generation in the comparison scenario suggests that most or all the NOx-emitting generation facilities in California’s non-attainment areas would continue to operate through 2045, which is inconsistent with attaining these health-based standards. Any modeling exercise should include constraints that reflect California’s air quality and environmental justice policies. The SB 100 report should make it clear that scenarios that are inconsistent with achieving air quality standards are unacceptable – just as the workshop presenters made clear that it would be unacceptable to implement a scenario that achieves SB 100 without meeting the greenhouse gas emissions limits in the Scoping Plan.

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<sup>4</sup> Cal. Pub. Util. Code § 913.11 (recodifying SB 100 joint report requirements section previously in § 454.53).

<sup>5</sup> South Coast AQMD, Final 2022 Air Quality Management Plan, Executive Summary (adopted December 2022), p. ES-5, *available at* <https://www.aqmd.gov/docs/default-source/clean-air-plans/air-quality-management-plans/2022-air-quality-management-plan/final-2022-aqmp/03-es.pdf>.

## **B. The Combustion Resource Retirement Scenario Demonstrates Massive Economic, Environmental, and Public Health Benefits.**

The Combustion Resource Retirement Scenario, critically, demonstrates that avoiding combustion to meet SB 100 requirements provides massive economic, environmental, and public health benefits.

The Combustion Resource Retirement Scenario consistently shows the largest public health and air quality benefits of all the model scenarios by a significant margin. Compared to the baseline, the Combustion Resource Retirement Scenario achieves complete elimination of both nitrogen oxide (“NOx”) and fine particulate matter (“PM2.5”) emissions from the electric sector by 2045.<sup>6</sup> For contrast, the other scenarios only reduce these emissions by 14 to 15%.<sup>7</sup> Accordingly, this scenario avoids far more adverse health events than any other scenario, resulting in:

- 85 to 140 avoided deaths
- 55,680 avoided asthma symptom events
- 2,150 avoided hay fever/rhinitis cases
- 100 fewer emergency room visits
- 39,710 fewer PM minor restricted activity days
- 6,690 PM work loss days
- 19,510 fewer ozone related school lost days
- 40 fewer non-fatal heart attacks<sup>8</sup>

The draft results estimate that the total health benefits of the Combustion Resource Retirement Scenario have a monetary value between \$1.35 and \$2.15 billion (2023 dollars), constituting 1.3 to 3 times the benefits of the next best performing scenarios (\$420 million to \$1.61 billion) and 4 to 7 times greater than the SB 100 Only scenario (\$190 million to \$300 million).<sup>9</sup> The Combustion Resource Retirement Scenario also yielded more avoided climate damages, achieving \$18 billion in climate damages compared to \$15-\$16 billion for the other compliance scenarios and just \$3 billion for the SB 100 only scenario.<sup>10</sup>

This financial accounting of benefits in the Combustion Resource Retirement Scenario help provide perspective for the significant value of this scenario over the others. Additional avoided

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<sup>6</sup> Docket 23-SB-100, *Presentations - Workshop on 2025 SB 100 Joint Agency Report Draft Results*, Slide 68 (Feb. 19, 2026), available at <https://efiling.energy.ca.gov/GetDocument.aspx?tn=268689&DocumentContentId=105843> (hereinafter “Draft Results”).

<sup>7</sup> *Id.* at Slide 68

<sup>8</sup> *Id.* at Slide 69.

<sup>9</sup> *Id.* at Slide 70.

<sup>10</sup> *Id.* at Slide 72 (assuming a 2% social discount rate).

costs and benefits are required to fully capture the comparative benefits of this scenario, as we continue in the following subsections.

**C. The Draft Results Overstate the Cost of the Combustion Resource Retirement Scenario by Not Modeling Avoided Gas Infrastructure, Resource Adequacy Costs, and Other Increasing Costs Associated with Fossil Gas Plants.**

There may be further financial benefits that the draft results did not include but should be considered in the final SB 100 modeling and report.

Avoided gas infrastructure costs, for example, do not appear to be included in the Draft Results' Scenarios Modeled Costs estimate.<sup>11</sup> However, the costs associated with operations, maintenance, and fuel costs of California's aging, fossil-fired generation resources and related storage and distribution infrastructure is massive. California ratepayers and taxpayers currently pay the cost of maintaining and operating the infrastructure that supports gas plants, some of which will no longer be necessary under the Combustion Resource Retirement Scenario. Just one of the major California utilities, the Southern California Gas Company ("SoCalGas"), requested an *annual* forecast of \$47.8 million for its gas storage operations and construction costs,<sup>12</sup> which covers its existing gas storage facilities. If those facilities remain open to 2045, a conservative estimate of those facilities' operation and construction costs for just one California utility will be near \$1 billion in 2026 dollars.<sup>13</sup> One of those facilities is the Aliso Canyon facility, which operates at only partial capacity and caused massive climate and public health damage through its 2015 rupture. In a recent Public Utilities Commission filing, SoCalGas argues that this facility is necessary to support grid reliability.<sup>14</sup> Under a Combustion Resource Retirement Scenario, facilities like Aliso Canyon would be unnecessary, allowing regulators to retire these facilities and save ratepayers millions of dollars every year and billions of dollars over the course of the SB 100 planning period.

As noted by the Regenerate California Campaign in Kickoff comments, the cost of retaining California's polluting gas plants continues to increase. The Public Utilities Commission's most recent Resource Adequacy ("RA") Report said that RA contract prices continued to increase

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<sup>11</sup> *Id.* at Slide 45.

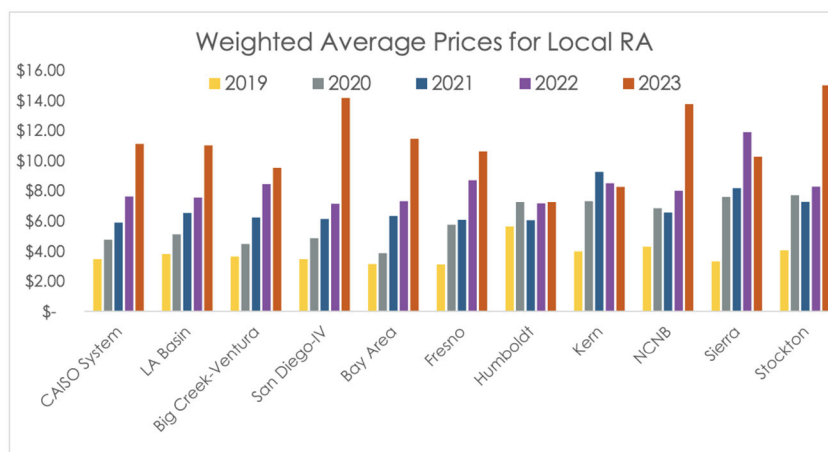
<sup>12</sup> A.22-05-015, Opening Brief of Southern California Gas Company (U904G) and San Diego Gas and Electric Company (U 902 M) in the Test Year 2024 General Rate Case, p. xix (Aug. 14, 2023), *available at* [https://www.socalgas.com/sites/default/files/SCG\\_SDGE\\_GRC\\_Opening\\_Brief.pdf](https://www.socalgas.com/sites/default/files/SCG_SDGE_GRC_Opening_Brief.pdf).

<sup>13</sup> Multiplying \$47.8 million by the 19 years between now and 2045 equals \$908.2 million in 2026 dollars.

<sup>14</sup> A.26-01-009, Application of Southern California Gas Company (U904G) in Compliance with Ordering Paragraph 6 of Decision 24-12-076, p. 1 (Jan. 15, 2026), *available at* <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M595/K083/595083702.PDF>.

significantly between 2022 and 2023, with the weighted average System RA price in September 2023 reaching \$24.07/kW-month, a 93% increase from 2022.<sup>15</sup> The 85th percentile of September 2023 contracts in Northern California reached \$48.50/kW-month.<sup>16</sup> Gas plants currently obtain the majority of RA contracts and benefit from considerable market power, particularly in obtaining local RA contracts. The local RA price trends across recent years shows the effects of concentrating market power in these resources.

**Figure 1: Weighted Average Price of Local RA (\$/kW-month), 2019-2023<sup>17</sup>**



In addition to high RA costs, there are many costs of retaining gas that make them economically risky, including high maintenance costs (especially for cycling units), the costs to maintain aging fossil fuel pipelines and infrastructure, and the high market costs due to market power. The 2021 Joint Agency SB 100 Report acknowledged that a comparison to the Commission’s average RA prices show that they are likely underestimating gas retention costs, and “[h]igher than modeled gas fleet maintenance costs may decrease economic gas retention or increase total scenario cost or both.”<sup>18</sup>

The final SB 100 modeling results should incorporate avoided fossil fuel investments, including avoided gas infrastructure, resource adequacy costs, and other increasing costs associated with

<sup>15</sup> Cal. Pub. Util. Comm’n Energy Div., *2023 Resource Adequacy Report*, p. 4 (Aug. 2025), available at <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2023-resource-adequacy-reportv2.pdf> (hereinafter “2023 Resource Adequacy Report”).

<sup>16</sup> *Id.* at 25.

<sup>17</sup> *Id.* at 31.

<sup>18</sup> Docket 19-SB-100, *2021 SB 100 Joint Agency Report*, p. 79 (Mar. 2021), available at <https://efiling.energy.ca.gov/EFiling/GetFile.aspx?tn=237167&DocumentContentId=70349> (hereinafter “2021 SB 100 Report”).

fossil gas plants, into the Combustion Resource Retirement Scenario to ensure the most accurate cost estimate possible.

**D. The Draft Results Overstate the Cost of the Combustion Resource Retirement Scenario and All Scenarios by Failing to Consider Distributed Energy Resources.**

The Draft Results failed to consider distributed energy resources (“DER”) and virtual power plants (“VPP”) as expansion resources, meaning that the modeling results may be missing opportunities for lower cost resources. The list of expansion candidates in the SB 100 Inputs and Assumptions slides do not include DERs, including but not limited to distributed renewables and storage or aggregated DER resources functioning as VPPs.<sup>19</sup>

Failing to consider DERs — such as rooftop solar, battery storage, demand response programs, and electric vehicle charging — and the virtual power plants that aggregate them might be resulting in overstated costs for all of the scenarios, particularly the Combustion Resource Retirement Scenario. DERs and VPPs offer compelling advantages as capacity expansion candidates for the modern grid. Unlike traditional centralized generation, DERs are modular and can be deployed incrementally, reducing the financial risk of large utility investments. Furthermore, these resources can be deployed closer to load centers, meaning they can reduce transmission and distribution congestion, defer or avoid costly infrastructure upgrades, and reduce reliance on gas plants that would otherwise be contracted for local reliability. If SB 100 modeling fails to consider these resources, then the results will require the selection of other, more expensive alternatives.

Furthermore, VPPs can offer grid benefits by better coordinating resources already on the grid. VPPs can generate grid benefits from DERs that are already installed and deployed to the grid by coordinating the dispatch to benefit the grid. Individual customers deploy DERs for their own purposes, but VPPs can pay customers to provide grid benefits during certain grid conditions rather than just individual customer needs. Unless and until SB 100 modeling considers VPPs and DERs, the capacity expansion results will exclude this possibility and potentially overstate scenario costs.

These effects are particularly pronounced for the Combustion Resource Retirement Scenario because the proposed capacity increases are much larger than the other scenarios.<sup>20</sup> Without addressing this issue, the costs of each scenario are likely overstated and unrealistic.

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<sup>19</sup> Docket 23-SB-100, *SB 100 Inputs and Assumptions*, Slide 15 (Feb. 19, 2026), available at <https://efiling.energy.ca.gov/GetDocument.aspx?tn=268979&DocumentContentId=106173> (hereinafter “SB 100 Inputs and Assumptions”).

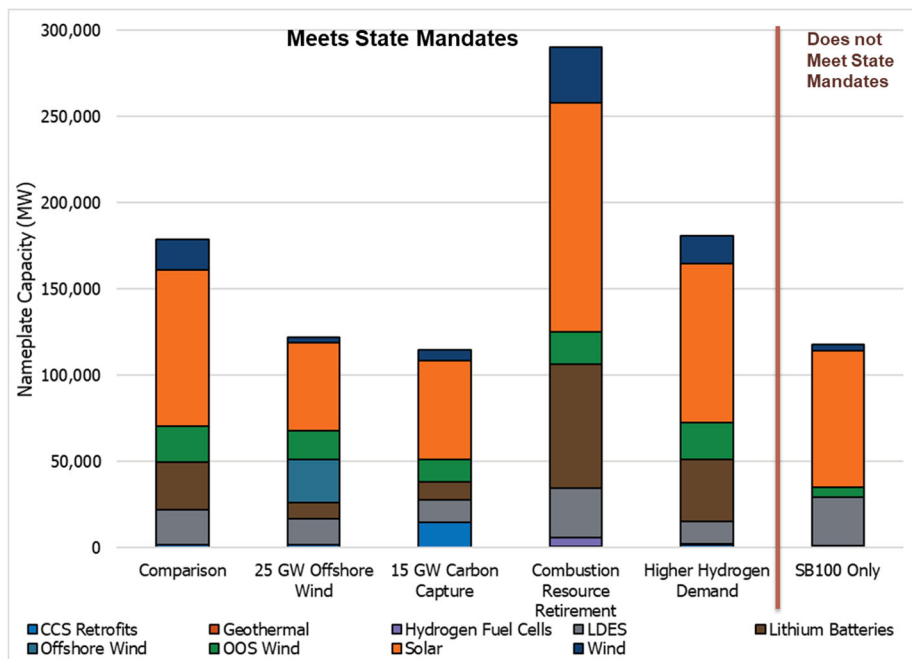
<sup>20</sup> Draft Results at Slide 36.

Accordingly, we urge the Commission to update the expansion candidate list to include DERs and VPPs.

**E. The Exclusion of Offshore Wind Capacity in the Combustion Resource Retirement Scenario Likely Artificially Inflates Costs; a Combustion Resource Retirement + Limited OSW Sensitivity Should Be Analyzed.**

The Joint Agencies should investigate and publish results of a Combustion Resource Retirement + Offshore Wind sensitivity to determine how OSW resources would impact overall system capacity and costs. Modeling data released to stakeholders in March shows that the projected 2045 Combustion Resource Retirement Scenario and every other scenario besides the 25 GW Offshore Wind scenario includes no offshore wind capacity. However, the Reference Scenario projected including 4,531 MW of offshore wind capacity by 2045. Whether OSW resources were artificially excluded or simply not selected in the scenarios, the projected capacity needs for the Combustion Resource Retirement Scenario are so large that the Joint Agencies should analyze a sensitivity that forces at least the amount of OSW capacity present in the Reference Scenario (4,531 MW) for the Combustion Resource Retirement Scenario.

**Larger Buildout of Renewables Required for Combustion Retirement<sup>21</sup>**



The Combustion Resource Retirement Scenario projected vast quantities of nameplate capacity, including 135 GW of additional renewable capacity above the Comparison Scenario.<sup>22</sup> That

<sup>21</sup> *Id.* at Slide 36

<sup>22</sup> *Id.* at Slide 36.

additional capacity further includes 5 GW of hydrogen fuel cells to provide winter power.<sup>23</sup> These capacity needs are more than double the projected capacity needs produced in the 25 GW OSW scenario.<sup>24</sup> Given the land use and environmental impacts at stake from significant resource development, the Joint Agencies should evaluate how many of those impacts might be mitigated through a modest level of forced OSW capacity.

Specifically, we recommend that the Joint Agencies analyze a sensitivity that forces at least the amount of OSW capacity present in the Reference Scenario (4,531 MW) for the Combustion Resource Retirement Scenario in order to better evaluate the capacity and cost tradeoffs of incorporating a minimal amount of OSW resources into the Combustion Resource Retirement Scenario.

### **III. FOSSIL FUELED GAS PLANTS WITH CCS, WHICH DIRECTLY VENT CO<sub>2</sub> INTO THE ATMOSPHERE, ARE NOT “ZERO CARBON RESOURCES”; THE JOINT AGENCIES’ DETERMINATION TO THE CONTRARY VIOLATES SB 100, LACKS EVIDENTIARY SUPPORT, SCRAMBLES MARKET SIGNALS, PROLONGS POLLUTION HARMS, AND INCREASES THE RISK OF COSTLY STRANDED ASSETS.**

In the 2021 SB 100 Report, the Joint Agencies rightly excluded gas generation with CCS from the modeling because there was “[l]ack of cost and performance data for 100 percent carbon capture.”<sup>25</sup> They reasoned that “[p]artially decarbonized resources (that is, with less than 100 percent of onsite carbon emissions captured and stored) did not meet the joint agencies’ criteria for zero-emission technologies”<sup>26</sup> In other words, the Joint Agencies reached the sound conclusion in 2021 that if a resource directly emits CO<sub>2</sub> into the atmosphere, it is not “zero-carbon.”

Now, in the Draft Results, without citing any new cost and performance data of 100 percent carbon capture, the Joint Agencies appear to have backpeddled on their prior reasoning and contorted the SB 100 mandate, stating that CCS can be “SB 100 compliant” and thus a “zero-carbon resource” some of the time, based on the percentage of carbon that the CCS project claims to capture. This reasoning lacks a basis in law and fact. SB 100 does not contemplate such an approach. Further, it rests on the misguided assumption that industry’s claimed capture rates are reliable (which they are not), omits upstream methane leakage and downstream storage and safety risks, fails to substantiate energy penalty assumptions, and will prolong reliance on costly

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<sup>23</sup> *Id.* at Slide 36.

<sup>24</sup> *Id.* at Slide 36.

<sup>25</sup> 2021 SB 100 Report at 9.

<sup>26</sup> *Id.* at 57.

and polluting fossil-fueled generation. We urge the Joint Agencies to uphold the sound reasoning that it applied in 2021 and to exclude CCS as a candidate resource.

**A. The Joint Agencies’ Contorted Treatment of CCS Is Inconsistent with the Plain Meaning of “Zero Carbon Resource” in SB 100.**

As an initial matter, the plain text of SB 100 requires “zero carbon resources” and “renewable energy resources” to supply 100 percent of all retail sales by 2045.<sup>27</sup> It does not allow resources that are not zero-carbon to count toward this goal. A resource cannot be “zero-carbon” even if it claims to capture a percentage of its emissions because it is still emitting carbon directly into the atmosphere. If the Legislature intended to create the percentage-based system that the Joint Agencies improperly propose in the Draft Results, it would have said so in the statute. It did not. Notably, in 2022, when the Legislature amended SB 100 via SB 1020, it maintained the statute’s existing structure, reaffirming that only renewable and zero carbon resources count toward the State’s clean energy goals. The Joint Agencies’ suggestion that CCS is “SB 100 compliant” defies this clear Legislative direction.

**B. The Joint Agencies Do Not Provide Evidence to Support the Assumed Capture Rates (Which Have Never Been Demonstrated in the Real World) and Provide No Mechanism to Track Performance, Account for Future Underperformance, and Ensure SB 100 Compliance.**

Not only is the Joint Agencies’ approach to CCS inconsistent with SB 100, it also fails to support the modeled capture rates and incorrectly presumes that CCS capture rates are reliably estimated and reported. Specifically, the modeling assumes 97% capture at fossil-fuel gas plants, 95% capture at retrofitted fossil-fueled plants and 90% at biomass plants but provides no evidence to support these percentages.<sup>28</sup>

Evidence from across the world, including California, shows that these capture rates are unlikely to be achieved and that CCS developers consistently overestimate the capture rates of their projects. In Australia, for example, the Gordon CCS project represented that it would capture 80 percent of the project emissions, but data show that the capture for 2023 was a mere 30 percent

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<sup>27</sup> Cal. Pub. Util. Code § 454.53(a) (“It is the policy of the state that eligible renewable energy resources and zero-carbon resources supply 90 percent of all retail sales of electricity to California end-use customers by December 31, 2035, 95 percent of all retail sales of electricity to California end-use customers by December 31, 2040, 100 percent of all retail sales of electricity to California end-use customers by December 31, 2045, and 100 percent of electricity procured to serve all state agencies by December 31, 2035.”) (emphasis added).

<sup>28</sup> SB 100 Inputs and Assumptions at Slide 15.

and that performance is diminishing over time.<sup>29</sup> In Texas, the Petra Nova CCS project, one of the largest CCS plants in the world, reported a 33 percent capture rate before it was shuttered,<sup>30</sup> while the Shell Quest CCS project in Canada has only captured 48 percent.<sup>31</sup> In Illinois, a CCS project at a fertilizer plant has captured only 10-12 percent of the facility emissions.<sup>32</sup>

In California, it is not clear what the expected capture rates of California CCS projects are, given the lack of credible evidence. For example, while the lead agency for the Carbon Terravault CCS project in Kern County estimated a capture rate of between “80 to 90 percent,”<sup>33</sup> California Resource Corporation has touted to the California Public Utilities Commission (“CPUC”) an expected capture rate of 95 percent for that same project.<sup>34</sup> The Joint Agencies should not take a face value developer estimates in the modeling, as they appear to have done here.

Furthermore, this lack of reliable data on one CCS project’s expected performance and cost is alarming and does not bode well for SB 100 planning: What percentage will the Joint Agencies use for each CCS project? What method will the Joint Agencies use to track whether the assumed capture rates are actually achieved? How will SB 100 planning adjust if and when the originally assumed percentages are found to be inaccurate? These core questions are not

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<sup>29</sup> Amandine Denis-Ryan et al., *Gorgon CCS Underperformance Hits New Low in 2023-24*, Industry for Energy Economics and Financial Analysis (“IEFFA”) (Nov. 28, 2024), available at <https://ieefa.org/resources/gorgon-ccs-underperformance-hits-new-low-2023-24/>. As noted by IEFFA, “[p]articularly concerning is the fact that Gorgon’s performance has decreased over time, with a marked drop in the percentage of CO2 captured in the past three years.”

<sup>30</sup> Emma Young, *WA’s Gorgon Project Fails to Deliver on Pollution Deal, Adding Millions of Tonnes of Carbon a Year*, The Sydney Morning Herald (Feb. 16, 2021), available at <https://www.smh.com.au/national/millions-of-tonnes-of-carbon-added-to-pollution-as-gorgon-project-fails-capture-deal-20210215-p572na.html>.

<sup>31</sup> Sam Meredith, *Shell’s Massive Carbon Capture Facility in Canada Emits Far More than it Captures, Study Says*, CNBC (Jan. 24, 2022), <https://www.cnbc.com/2022/01/24/shell-ccs-facility-in-canada-emits-more-than-it-captures-study-says.html>.

<sup>32</sup> Brendan Gibbons, *In Illinois, a Massive Taxpayer-Funded Carbon Capture Project Fails to Capture about 90 Percent of Plant’s Emissions*, Oil and Gas Watch (Apr. 25, 2024), available at <https://news.oilandgaswatch.org/post/in-illinois-a-massive-taxpayer-funded-carbon-capture-project-fails-to-capture-about-90-percent-of-plants-emissions>.

<sup>33</sup> Kern County Planning and Natural Resources Department, *Staff Report*, p. 45 (Oct. 21, 2024), [https://psbweb.kerncounty.com/UtilityPages/Planning/StaffReports/BOSHearings/StaffReport/2024/102124\\_Carbon\\_Terravault\\_1\\_California\\_Resources\\_Corporation.pdf](https://psbweb.kerncounty.com/UtilityPages/Planning/StaffReports/BOSHearings/StaffReport/2024/102124_Carbon_Terravault_1_California_Resources_Corporation.pdf)

<sup>34</sup> R.20-05-003, CPUC Energy Division, *Integrated Resources Planning 2nd Workshop: Reliable and Clean Power Procurement Program Staff Proposal*, Slide 77 (June 24, 2025), available at [https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/rcppp/rcppp-slides-day-2\\_ver2.pdf](https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/rcppp/rcppp-slides-day-2_ver2.pdf). R.25-06-019, Proposed Decision, p. 48 (Jan. 14, 2026), available at <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M595/K083/595083681.PDF>. The PD summarizes comments from CRC as indicating that CCS retrofits on gas plants are “easy, quick, affordable, mature, and scalable to meet GHG goals.” For the reasons detailed herein and in other comments, this self-interested summary is inaccurate and cannot be the basis for the Commission’s decision.

addressed in the Draft Results. Without a tracking mechanism, there will be no way to know whether SB 100 targets have been met because the amount of actual capture will not be known. Thus, in relying on the unreliable metric of carbon capture rates to allow CCS to be a “zero carbon resource” part of the time the Joint Agencies put California at risk missing its SB 100 goals.

**C. The Joint Agencies Do Not Account for Upstream Methane Leakage and Improperly Assume CCS Storage Potential Throughout the Central Valley and in the Los Angeles Area Without Regard to Seismic and Other Safety Risks.**

Also left unaddressed by the Joint Agencies are the glaring issues of upstream methane leakage, which can overwhelm any carbon benefit of carbon capture from CCS<sup>35</sup> as well as new information about long-term viable carbon storage, which suggests California’s seismic risk precludes it offering reliable carbon capture.<sup>36</sup> Slide 29 of the Inputs and Assumptions depicts “CO2 Storage Potentials” and indicates that an analysis by Carbon Solutions and EPRI finds such potential exists in the Central Valley and the Los Angeles area.<sup>37</sup> However, a recent study examining a prudent planetary limit for geologic carbon storage published in *Nature* excludes all of California due to seismic risk. Figure 2 depicts these findings.

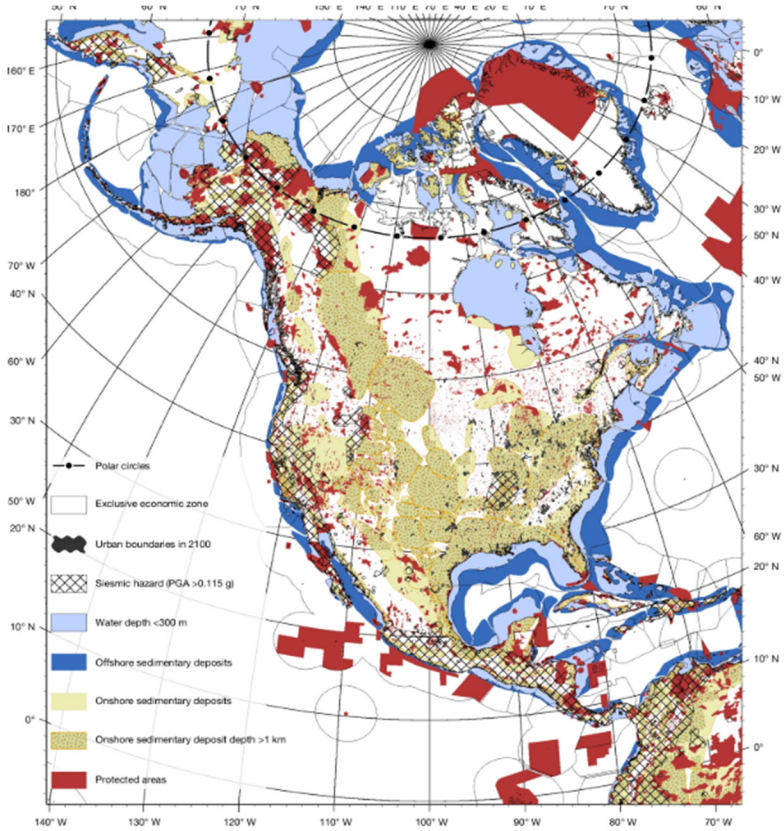
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<sup>35</sup> Thomas J.P. Hersbach et al., *Flexible Operation and Fugitive Methane Emissions Limit the Potential of Power Plant Carbon Capture and Storage*, *The Electricity Journal*, Vol. 38, p. 2 (Sept. 2025), available at <https://www.sciencedirect.com/science/article/pii/S1040619025000399?via%3Dihub>; see also Diana Burns & Emily Grubert, *Contribution of Regionalized Methane Emissions to Greenhouse Gas Intensity of Natural Gas-Fired Electricity and Carbon Capture in the United States* (June 2021), available at <https://pubs.acs.org/action/showCitFormats?doi=10.1021/acs.estlett.1c00531&ref=pdf> (finding methane emissions constrain the greenhouse gas avoidance or removal potential of natural-gas-fired carbon capture).

<sup>36</sup> Matthew J. Gidden et al., *A Prudent Planetary Limit for Geologic Carbon Storage*, *Nature*, Vol. 645 (Sept. 2025), available at <https://www.nature.com/articles/s41586-025-09423-y>.

<sup>37</sup> SB 100 Inputs and Assumptions at Slide 29.

**Figure 2: Spatially Explicit Global Carbon-Storage Potential in Sedimentary Basins.**<sup>38</sup>



The same study also finds that even low levels of CO<sub>2</sub> leakage from the storage facility itself can overwhelm any purported carbon benefit—specifically, annual leakage of CO<sub>2</sub> from storage sites greater than 0.01% can negate the climate benefits of stored CO<sub>2</sub>.<sup>39</sup> Based on the information made available to the public (the Carbon Solution/EPRI analysis has not been disclosed), it is not clear whether the Joint Agencies considered seismic risk at all let alone the findings of this published analysis.

It is also not clear whether the Joint Agencies contemplated safety risks associated with CO<sub>2</sub> leaks in pipelines and storage facilities when determining the potential carbon storage areas and the pipeline buildout costs depicted in Slide 21 of the Inputs and Assumptions.<sup>40</sup> CO<sub>2</sub> pipelines associated with CCS projects present safety risks. For example, in 2020, a pipeline transporting carbon dioxide in Mississippi leaked, hospitalizing dozens of people.<sup>41</sup> In addition, injection of

<sup>38</sup> Matthew J. Gidden et al., *A Prudent Planetary Limit for Geologic Carbon Storage*, *Nature*, Vol. 645, Figure 1 (2025), <https://www.nature.com/articles/s41586-025-09423-y>.

<sup>39</sup> *Id.*

<sup>40</sup> SB 100 Inputs and Assumptions at Slide 29.

<sup>41</sup> Dan Zegart, *The Gassing of Satartia*, *HuffPost* (Aug. 26, 2021), available at [https://www.huffpost.com/entry/gassing-satartia-mississippi-co2-pipeline\\_n\\_60ddea9fe4b0ddef8b0ddc8f](https://www.huffpost.com/entry/gassing-satartia-mississippi-co2-pipeline_n_60ddea9fe4b0ddef8b0ddc8f).

CCS fluids underground can threaten water sources. A CCS plant in Illinois was recently forced to shut down for nearly a year when the U.S. EPA found that it was violating its Safe Drinking Water Act permit by injecting fluids into an unauthorized zone thousands of feet below the surface.<sup>42</sup> These serious risks have not been thoroughly studied and addressed in California, and it is unclear whether they were considered at all in the Draft Results. Especially given the drinking water crisis that already exists in the Central Valley,<sup>43</sup> and the population centers that currently exist in areas currently identified as areas with “CO2 Storage Potential,”<sup>44</sup> the Joint Agencies must undertake a careful analysis of these risks, that is fully vetted by the public, before assuming CCS is a viable and prudent option in California.

#### **D. The Joint Agencies Do Not Disclose an Assigned Energy Penalty for CCS.**

While a staff response to a Draft Results Workshop question indicates that an energy penalty was assigned to CCS in the Draft Results,<sup>45</sup> the Joint Agencies’ failure to actually disclose this figure in their modeling inputs and assumptions means that the public cannot probe the validity of the penalty level assigned or assess whether it is based on the best available science. Studies show that the energy penalty associated with CCS can be substantial. According to the Intergovernmental Panel on Climate Change, “the energy penalty increases the fuel requirement for electricity generation by 13–44%”<sup>46</sup> Why did staff opt for the lower end of this

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<sup>42</sup> Carlos Anchondo, *Carbon Storage Site That Leaked Set to Restart Injections*, E&E News (Aug. 1, 2025), <https://www.eenews.net/articles/carbon-storage-well-that-leaked-set-to-restart-injections/>; U.S. Environmental Protection Agency (“EPA”), *EPA Orders Archer Daniels Midland to Ensure Environmental Compliance of Carbon Sequestration Well in Decatur, Illinois* (Aug. 13, 2025), available at <https://www.epa.gov/newsreleases/epa-orders-archer-daniels-midland-ensure-environmental-compliance-carbon-sequestration>.

<sup>43</sup> Rachel Becker, *Drinking Water of Almost a Million Californians Failed to Meet State Requirements* (June 25, 2024) <https://calmatters.org/environment/2024/06/california-drinking-water-failing-systems/> (finding almost 400 water systems serving nearly a million Californians do not meet state requirements for safe and reliable drinking water supplies.).

<sup>44</sup> SB 100 Inputs and Assumptions at Slide 29.

<sup>45</sup> CEC, *Draft Results Workshop Recording*, 01:07:32, available at <https://energy.zoom.us/rec/share/vmSYRtVn0bDIJbPIEvMVcK9ggd7gWjC2QEMxNa2944prqHxHjXL Tuo96VdzfF5jU.xoGpUOrCAJT1zBzP?startTime=1771521336000> (“Q: I have questions about some of the assumptions underlying CCS. What energy penalty was assumed for CCS use? And also, what capture rate is assumed. I’m confused about potential consideration of CCS as zero carbon if there is not 100% capture. Thank you. A: I’m not sure about a capture limit, I would have to get back to you on that. There is a heat rate penalty assumed, though, and I think it’s about 10 or 15%. So, you know, we do assume that those power plants become less efficient if they’re retrofitted with CCS... That, yeah, [the capture rate] is, 95%.”) (hereinafter “Workshop Recording”).

<sup>46</sup> Intergovernmental Panel on Climate Change, *WG III Contribution to the Sixth Assessment Report*, p. 6-38 (Apr. 4, 2022), available at [https://www.ipcc.ch/report/ar6/wg3/downloads/report/IPCC\\_AR6\\_WGIII\\_Chapter\\_06.pdf](https://www.ipcc.ch/report/ar6/wg3/downloads/report/IPCC_AR6_WGIII_Chapter_06.pdf); see also John Rogers et al., *Beyond the Smokestack: Assessing the Impacts of Approaches to Cutting Gas Plant Pollution*, p. 8 (Oct. 15, 2024), available at <https://www.ucs.org/sites/default/files/2024->

range? What performance data was considered? These questions remain unanswered in the Draft Results and in the disclosed modeling assumptions.

#### **D. The Joint Agencies' Treatment of CCS Undermines Market Signals to Zero-Emitting, Clean Resources.**

In a related vein, allowing unreliable, carbon-emitting CCS projects to count as “zero carbon” sends mixed signals to the market. As emphasized by stakeholders on the Draft Results Workshop panel, definitional clarity and clear market signals are needed for successful clean resource deployment. As noted above, the importance of such signals was underscored by Governor Brown who, upon signing SB 100 into law, indicated that it would “[send] a clear signal to markets to expand clean energy generation”<sup>47</sup> The intent was to prioritize truly zero-carbon resources so that they can deploy at scale and to require the planning necessary to ensure they provide 100% of the state’s electric power by 2045. The Joint Agencies’ definitional contortions are scrambling these messages and making resource planning more challenging.

#### **E. Reliance on CCS Will Prolong and Exacerbate Harms from Fossil-Fueled Generation.**

The Draft Results Reference Scenario assumes 1.6 GW of CCS capacity,<sup>48</sup> and the 15 GW Carbon Capture Scenario assumes CCS retrofits make up about 10% of total generation.<sup>49</sup> Adding CCS retrofits to California’ gas plants will extend their life and likely increase their emissions because they must run more often to power the CCS equipment,<sup>50</sup> and as explained in more detail below in section Section VII.B. below, these gas plants already disproportionately impose pollution harms on California’s most vulnerable residents. What is more, the increases in gas plant generation associated with powering CCS equipment result in more harmful non-CO2

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[10/Beyond the Smokestack issue-brief.pdf](#) (citing Suraj Vasudevan et al., *Energy Penalty Estimates for CO2 Capture: Comparison between Fuel Types and Capture-Combustion Modes*, Energy, Vol. 103, pp. 709-714 (May 2016), available at <https://doi.org/10.1016/j.energy.2016.02.154>).

<sup>47</sup> Governor Edmund G. Brown to Members of the California State Senate, Letter (Sept. 10, 2018), available at <https://archive.gov.ca.gov/archive/gov39/wp-content/uploads/2018/09/SB-100-Signing-Message.pdf> (emphasis added) (hereinafter “Governor Brown Letter to State Senate”).

<sup>48</sup> Draft Results at Slide 28

<sup>49</sup> *Id.* at Slides 33-35, 41.

<sup>50</sup> John Rogers et al., *Beyond the Smokestack: Assessing the Impacts of Approaches to Cutting Gas Plant Pollution*, p. 8 (Oct. 15, 2024), available at <https://www.ucs.org/sites/default/files/2024-10/Beyond the Smokestack issue-brief.pdf> (citing Suraj Vasudevan et al., *Energy Penalty Estimates for CO2 Capture: Comparison between Fuel Types and Capture-Combustion Modes*, Energy, Vol. 103, pp. 709-714 (May 2016), available at <https://doi.org/10.1016/j.energy.2016.02.154>).

air pollutants, such as NO<sub>x</sub> and particulate matter, which are not captured by CCS.<sup>51</sup> In the case of the TerraVault Project in Kern County, which includes the Elk Hills gas plant, the project’s environmental impacts report finds that the project’s increased emissions of NO<sub>x</sub> and particulate matter are “significant and unavoidable.”<sup>52</sup>

In addition to increased gas plant emissions, amine-based solvents used by CCS equipment are potential carcinogens that pose environmental and public health risks, including smog formation and drinking water contamination.<sup>53</sup> Indeed, harmful amine and carcinogenic nitrosamine emissions have been detected at CCS projects.<sup>54</sup> Further, after the solvent is used, the degraded amine product becomes hazardous waste.<sup>55</sup>

Based on the publicly available data, the Joint Agencies do not appear to acknowledge or quantify these health risks, much less the financial impacts they cause.

#### **F. CCS Is Not Affordable.**

Finally, CCS deployment is at odds with the affordability focus that CPUC President John Reynolds emphasized at the Draft Results Workshop because it would foist the cost of stranded fossil assets on California ratepayers. According to a Stanford University study, the levelized cost of a CCS project depends on the gas plant’s capacity factor, with lower capacity factors

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<sup>51</sup> See Mark Z. Jacobson, *The Health and Climate Impacts of Carbon Capture and Direct Air Capture*, Energy and Environmental Science, Vol. 12, pp. 5, 7 (2019), available at <https://web.stanford.edu/group/efmh/jacobson/Articles/Other/19-CCS-DAC.pdf> (concluding that CCS are “not close to zero-carbon technologies” and that CCS does not capture “CO, NO<sub>x</sub>, SO<sub>2</sub>, organic gases, mercury, toxins, black and brown carbon, fly ash, and other aerosol components.”).

<sup>52</sup> Kern County Planning and Natural Resources Department, *Recirculated Draft Environmental Impact Report*, p. 1-12 (June 2024), available at [https://psbweb.kerncounty.com/planning/pdfs/eirs/ctv1/CTV1\\_RDEIR\\_Vol1.pdf](https://psbweb.kerncounty.com/planning/pdfs/eirs/ctv1/CTV1_RDEIR_Vol1.pdf) (“The project’s total emissions would exceed the San Joaquin Valley Air Pollution Control District thresholds for nitrogen oxides (NO<sub>x</sub>), particulate matter with a diameter of 10 micrometers or less (PM<sub>10</sub>), and particulate matter with a diameter of 2.5 micrometers or less (PM<sub>2.5</sub>), for which the project region is nonattainment under an applicable federal or State ambient air quality standard. With the implementation of Mitigation Measure (MM) 4.3-1 and MM 4.3-8, the impact would remain significant and unavoidable.”).

<sup>53</sup> Yukyan Lam et al., *Environmental Justice Concerns with Carbon Capture and Hydrogen Co-Firing in the Power Sector*, p. 16 (June 2024), available at <https://njeja.org/wp-content/uploads/2024/07/CCS-EJ-White-Paper.pdf>.

<sup>54</sup> Kevin Maik Jablonka et al., *Machine Learning for Industrial Processes: Forecasting Amine Emissions from a Carbon Capture Plant*, Science Advances, Vol. 9 (Jan. 4, 2023), available at <https://www.science.org/doi/10.1126/sciadv.adc9576>; Alicia J. Reynolds et al., *Towards Commercial Scale Postcombustion Capture of CO<sub>2</sub> with Monoethanolamine Solvent: Key Considerations for Solvent Management and Environmental Impacts*, Vol. 47 (Feb. 12, 2012), available at <https://pubs.acs.org/doi/10.1021/es204051s>.

<sup>55</sup> Lam, *supra* note 53 at 16.

increasing costs.<sup>56</sup> This cost issue is exacerbated if the deployment of clean energy generation and storage drives the capacity factor of natural gas combined cycle plants below current levels.<sup>57</sup> Experts have emphasized cost uncertainty noting that “after decades of promotion and many billions of dollars spent, we still have next to no real-world data about the costs of running, maintaining and monitoring large C.C.S. projects.”<sup>58</sup> Original industry price estimates have also been wildly inaccurate. For example, Southern Company’s Kemper plant was originally forecast to cost \$2.2 billion, but ultimately ballooned to \$6.66 billion.<sup>59</sup> Southern Company then gave up on CCS in 2017, demolished part of the plant, and shifted to a gas-powered plant without CCS.<sup>60</sup> The Illinois FutureGen project, despite receiving \$200 million in subsidies, was ultimately scrapped due to cost and technology concerns.<sup>61</sup> As noted above, Petra Nova, a coal-fired CCS project in Texas, was plagued with cost overruns, prolonged outages, and failed to meet its CO<sub>2</sub> capture goals before it was shut down.<sup>62</sup> Given this track record, a Massachusetts Institute of Technology professor deemed government subsidies for CCS are “a counterproductive waste of money, backed by the fossil fuel industry.”<sup>63</sup>

To the extent there are cost and efficiency gains to be had from taking advantage of existing interconnections at gas plants,<sup>64</sup> such infrastructure should be harnessed for the transition to a truly zero-carbon grid, consistent with SB 100.

In sum, given the clear mandate of SB 100 and the myriad risks and costs presented by CCS, we urge the Joint Agencies to uphold their 2021 determination that a “zero-carbon resource” cannot directly vent carbon into the atmosphere, exclude CCS resources altogether, send a clear signal

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<sup>56</sup> Hersbach, *supra* note 35 at 2.

<sup>57</sup> *Id.*

<sup>58</sup> Charles Harvey & Kurt House, *Every Dollar Spent on This Climate Technology Is a Waste*, The New York Times (Aug. 16, 2022), available at <https://www.nytimes.com/2022/08/16/opinion/climate-inflation-reduction-act.html>.

<sup>59</sup> MIT Carbon Capture and Sequestration Technologies, *Kemper County IGCC Fact Sheet: Carbon Dioxide Capture and Storage Project*, available at <https://sequestration.mit.edu/tools/projects/kemper.html> (last visited Oct. 31, 2025).

<sup>60</sup> David Schlissel, *IEEFA U.S.: Southern Company Demolishes Part of the \$7.5 Billion Kemper Power Plant in Mississippi* (Oct. 14, 2021), available at <https://ieefa.org/resources/ieefa-us-southern-company-demolishes-part-75-billion-kemper-power-plant-mississippi>.

<sup>61</sup> Jeffrey Rissman & Robbie Orvis, *Carbon Capture & Storage Is Too Expensive for Reducing Power Sector Emissions*, CleanTechnica (2017), available at <https://cleantechnica.com/2017/08/18/carbon-capture-storage-expensive-reducing-power-sector-emissions/>.

<sup>62</sup> National Energy Technology Laboratory, *W.A. Parish Post-Combustion CO<sub>2</sub> Capture and Sequestration Demonstration Project: Final Scientific/Technical Report*, U.S. Department of Energy (“DOE”) (Mar. 31, 2020), available at <https://www.osti.gov/servlets/purl/1608572>.

<sup>63</sup> Harvey & House, *supra* note 58.

<sup>64</sup> SoCalGas Comments, p. 8; CRC Comments, p. 7.

that truly clean resources will be prioritized, and protect Californians from expensive and polluting projects that are neither clean nor zero-carbon.

#### **IV. THE HIGHER HYDROGEN DEMAND SCENARIO IS SO IMPLAUSIBLE THAT IT THREATENS TO MISLEAD POLICYMAKERS ABOUT THE REASONABLENESS OF PLANNING FOR MASSIVE HYDROGEN PRODUCTION.**

The Higher Hydrogen Demand scenario includes enough hydrogen production to supply 85% of the demand assumed in the 2022 Scoping Plan.<sup>65</sup> The Scoping Plan’s projections for hydrogen demand were unjustified, high-end estimates when it was published, and the developments since 2022 only dim the prospects for hydrogen demand. For instance, CARB hard-coded an assumption into the Scoping Plan modeling that half of zero-emissions heavy-duty trucks would operate on hydrogen, without analyzing whether hydrogen offered the most economic choice for decarbonizing this much of the trucking sector. More recent data indicates a smaller role for hydrogen in the transportation sector based on its inability to compete against battery electric technology in most use cases. For example, the UK Climate Change Committee commissioned an economic analysis of competing options for decarbonizing vehicles and concluded that “[t]here will be no hydrogen cars or vans, and very little or potentially even no role for hydrogen in heavier vehicles.”<sup>66</sup> A Higher Hydrogen Demand scenario that fails to incorporate these recent learnings will significantly overshoot any plausible optimistic estimate for hydrogen demand, rendering it of little use to the Legislature or energy system planners. Indeed, the scenario could inadvertently undermine sound policymaking by creating the false impression that this level of hydrogen demand is feasible or consistent with a least-cost achievement of California’s climate goals.

We see value in including a high hydrogen-demand sensitivity analysis only if it includes viable assumptions about the load shapes and flexibility of the increased demand. The SB 100 modeling assumes that half of hydrogen energy demands are “baseload” and half are “dispatchable.”<sup>67</sup> It is difficult to predict the demand profile of hydrogen production facilities because electrolytic hydrogen production is not an industry that currently exists in California or any market at any meaningful scale. Based on the interconnection requests that California’s utilities have received, it appears data centers are a far more likely source of significant demand growth that was not

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<sup>65</sup> Draft Results at Slide 33.

<sup>66</sup> United Kingdom Climate Change Committee, *The Seventh Carbon Budget: Advice for the UK Government*, p. 146 (Feb. 2025), available at <https://www.theccc.org.uk/wp-content/uploads/2025/02/The-Seventh-Carbon-Budget.pdf>. The supporting documents for this report include ERM, *ZEV HDV Uptake Trajectories: Modeling Assumptions* (2024), available at <https://www.theccc.org.uk/wp-content/uploads/2025/02/ZEV-HDV-uptake-trajectories-ERM.pdf>.

<sup>67</sup> Draft Results at Slide 25.

included in the reference scenario. Thus, the Higher Hydrogen Demand scenario might shed some light on the potential impacts of an unforeseen data center buildout if the data centers have the flexible load patterns that the modelers assumed for hydrogen production. The main insight from the Higher Hydrogen Demand scenario may be that increased load from any source – including data centers – will not necessarily trigger a tremendous buildout of new capacity if the load is sufficiently flexible. If the SB 100 report includes this scenario, it should recognize this insight and the importance of policies that could require or provide powerful incentives for datacenters or other future load growth to operate flexibly.

## **V. THE DRAFT RESULTS MAY NOT INCORPORATE THE BEST AVAILABLE DATA ON THE COSTS OF GEOTHERMAL ENERGY.**

In most scenarios, the model did not select significant amounts of new geothermal capacity, if any.<sup>68</sup> The only type of geothermal resources that the modelers included as expansion candidates were conventional geothermal.<sup>69</sup> It is impossible to tell how the results of the modeling exercise would differ with more optimistic assumptions regarding geothermal costs or the inclusion of next-generation geothermal technologies because the agencies did not perform a sensitivity analysis with low-cost geothermal or with geothermal candidate resources that are less geographically constrained than conventional geothermal.

The SB 100 report should consider not just conventional geothermal resources, but also next-generation geothermal technologies. The U.S. Department of Energy report *Pathways to Commercial Liftoff: Next-Generation Geothermal Power* explains that conventional geothermal “has been dramatically constrained by its geographic limitations, relying on naturally-occurring thermal resources that only exist in niche locations.”<sup>70</sup> In contrast, “next-generation” technologies such as enhanced geothermal systems and closed loop geothermal systems “have the potential to engineer effective geothermal resources in commonly found environments, vastly expanding resource availability and potential commercial adoption.”<sup>71</sup> Researchers at Stanford University and Lawrence Berkeley National Laboratory found that enhanced geothermal could allow California’s geothermal capacity to increase tenfold, reaching 40 GW by 2045.<sup>72</sup> The SB

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<sup>68</sup> *Id.* at 34.

<sup>69</sup> SB 100 Inputs and Assumptions at Slide 15.

<sup>70</sup> U.S. Department of Energy, *Pathways to Commercial Liftoff: Next-Generation Geothermal Power*, p. 1 (Mar. 2024), available at <https://cdn.catf.us/wp-content/uploads/2025/06/09154348/doe-liftoff-nextgen-geothermal.pdf> (hereinafter “Next-Generation Geothermal Liftoff Report”).

<sup>71</sup> *Id.*

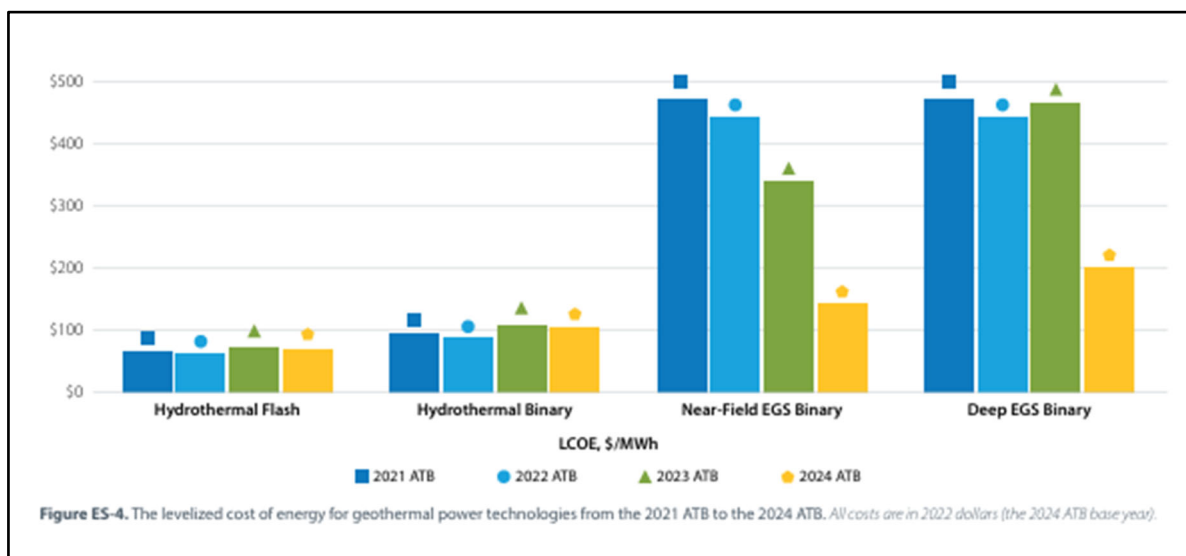
<sup>72</sup> Adam Hadhazy, *The Future of Geothermal for Reliable Clean Energy* (Feb. 21, 2025), available at <https://sustainability.stanford.edu/news/future-geothermal-reliable-clean-energy>.

100 report should not ignore the potential for this technology to replace fossil fuels with renewable power.

It is important to not only include enhanced geothermal as an expansion candidate, but to model that option using the best available data. The DOE Liftoff report found that industry is on pace to achieve DOE’s Enhanced Geothermal Shot Target of \$45/MWh by 2035.<sup>73</sup> At the workshop, Fervo’s representative recommended that the agencies could obtain recent, third-party validated cost information by consulting with the LSEs about the cost information they have received in solicitations. She explained that this data-gathering strategy would identify costs that are “significantly lower than the inputs and assumptions that are currently reflected in the modeling.”<sup>74</sup> At a minimum, the SB 100 report should acknowledge limitations in its cost data for geothermal and the potential impacts of overestimating costs for this renewable resource.

It is important for the SB 100 process to anticipate rapid cost declines for geothermal and consider options for delivering lower-cost geothermal power to California customers because the industry has recently seen important advances. NREL’s Annual Technology Baseline (“ATB”) dramatically reduced its estimate for the levelized cost of energy (“LCOE”) for enhanced geothermal systems between its 2023 ATB and its 2024 ATB, as illustrated in Figure 3.

**Figure 3: The Levelized Cost of Energy for Geothermal Power Technologies from the 2021 ATB to the 2024 ATB.**<sup>75</sup>



<sup>73</sup> Next-Generation Geothermal Liftoff Report at 3.

<sup>74</sup> Workshop Recording around 4:46.

<sup>75</sup> National Laboratory of the Rockies, *2025 U.S. Geothermal Market Report*, p. ix (Jan. 2026), available at <https://docs.nrel.gov/docs/fy26osti/91898.pdf>.

Further improvements and scaling of geothermal technologies could continue to drive this trend. One factor that previous geothermal cost forecasts may not have accounted for is the potential for deep-pocketed technology companies to invest in a buildout of geothermal generation for data centers, which could enable the technology to progress on its learning curve more rapidly.<sup>76</sup> Ultimately, a robust understanding of geothermal costs and resource availability will help California plan for compliance with SB 100 without relying on resources that are inconsistent with the Legislature’s direction to “transition to a zero-carbon electric system.”<sup>77</sup>

## **VI. THE JOINT AGENCIES’ FLAWED ASSUMPTIONS OF EXTENDED FEDERAL HYDROGEN TAX CREDITS AND LOW PRODUCTION COSTS LEAD THEM TO OVERESTIMATE THE ROLE OF HYDROGEN AS A GENERATION RESOURCE.**

Unless the Joint Agencies update their assumptions regarding hydrogen power, their modeling will give hydrogen an unwarranted advantage over resources like wind and solar by underestimating the costs of relying on hydrogen as a grid resource. One red flag in the agency’s recently released inputs and assumptions is that they rely on a model that suggests the subsidy from the federal 45V tax credits “is high enough to keep hydrogen fuel prices in the model at or below \$0.”<sup>78</sup> This statement suggests that the SB 100 modelers improperly assumed the 45V tax credits would be available in 2045. This is a flawed assumption even if the modeling assumes that all tax credits in the Inflation Reduction Act remain in place for their original duration. Before the 2025 rollback of the 45V tax credit, the subsidy was only available for ten years at facilities that begin construction before 2033.<sup>79</sup> Therefore, the modeling needs to correct any assumption that this subsidy is available for all hydrogen procured in 2045.

During the limited years that the 45V tax credit is available, the claim that it will drive hydrogen fuel prices to levels at or below \$0/kilogram is likely difficult to defend and based on outdated assumptions about the cost of electrolyzers. Even in a sunny state like Utah, Bloomberg predicts that the levelized cost of renewable electrolytic hydrogen will remain greater than the \$3/kilogram maximum 45V subsidy through mid-century.<sup>80</sup> Hydrogen produced in California may be more expensive than hydrogen produced in Utah as a result of California’s higher electric rates. It is unclear whether the modeling that developed the SB 100 report’s hydrogen cost assumptions used reasonable estimates for the cost of electricity used for hydrogen production because the Joint Agencies have not disclosed those assumptions.

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<sup>76</sup> *See id.* at 35 (“Several major tech companies have already turned to geothermal energy to power their operations reliably.”).

<sup>77</sup> Cal. Pub. Util. Code § 454.53(a).

<sup>78</sup> SB 100 Inputs and Assumptions at Slide 25.

<sup>79</sup> H.R. 5376, 117th Congress (2021-2022), available at <https://www.congress.gov/bill/117th-congress/house-bill/5376/text>.

<sup>80</sup> Payal Kaur, *US Clean Hydrogen Market Outlook*, Slide 13 (July 29, 2025), available at <https://efiling.energy.ca.gov/GetDocument.aspx?tn=265044>.

Outdated assumptions about the cost of electrolysis equipment are another factor that may have caused the modelers to underestimate the price of hydrogen fuel. The SB 100 modeling cites reports that the International Energy Agency published in 2016 and 2024 for the CAPEX of hydrogen production.<sup>81</sup> We were unable to locate the 2016 report online and, regardless, are unaware of why the Joint Agencies would rely on data from 2016 if data from 2024 is available from the same source. Alarming, the 2024 report indicates that the CAPEX for electrolysis is far more costly than what the Joint Agencies assumed. For instance, the Joint Agencies assume that CAPEX for water electrolysis is 900 USD/kW<sub>e</sub> today,<sup>82</sup> whereas the International Energy Agency's 2024 Global Hydrogen Review estimates 2023 costs of about 2,050-2,450 USD/kW<sub>e</sub>.<sup>83</sup> Moreover, the Joint Agencies assume that CAPEX for water electrolysis will be 700 USD/kW<sub>e</sub> in 2030,<sup>84</sup> whereas the International Energy Agency's 2024 Global Hydrogen Review estimates 2030 costs of about 900-1,450 USD/kW<sub>e</sub>.<sup>85</sup> This is a significant difference that could impact the competitiveness of hydrogen against other resources.

Finally, the Joint Agencies make the unreliable assumption that hydrogen storage will be available in depleted oil and gas reservoirs.<sup>86</sup> It would be improper to assume that hydrogen can safely be stored in California's depleted oil and gas reserves. A 2022 study that the University of California, Riverside prepared for the CPUC indicates that these facilities may be incompatible with hydrogen storage due to significant integrity and public safety issues, explaining:

Hydrogen is known to have serious detrimental effects on underground porous reservoirs. Twenty different hydrogen related phenomena have been observed that have negative effects on porous reservoirs' performance as storage facilities for methane-hydrogen gas blends. The most serious of these is bacterial growth

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<sup>81</sup> SB 100 Inputs and Assumptions at Slide 41.

<sup>82</sup> *Id.*

<sup>83</sup> IEA, *Global Hydrogen Review 2024*, p. 77, Figure 3.9 (Rev. Oct. 2024), available at <https://iea.blob.core.windows.net/assets/89c1e382-dc59-46ca-aa47-9f7d41531ab5/GlobalHydrogenReview2024.pdf>.

<sup>84</sup> SB 100 Inputs and Assumptions at Slide 41.

<sup>85</sup> IEA, *supra* note 83 at 77, Figure 3.9. The Joint Agencies' assumed hydrogen production CAPEX costs are also much lower than the cost information and projections being provided from industry. According to a 2023 report from the Hydrogen Council, CAPEX for a 1 GW electrolysis facility in the U.S. Gulf Coast would be 1,800-2,200 \$/kW in 2023 and 1,200-1,500 \$/kW in 2030. Hydrogen Council, *Hydrogen Insights 2023*, p. 21 (Dec. 2023), available at <https://hydrogencouncil.com/wp-content/uploads/2023/12/Hydrogen-Insights-Dec-2023-Update.pdf>.

<sup>86</sup> SB 100 Inputs and Assumptions at Slide 41.

and activity, resulting in loss of gas volume, potential for H<sub>2</sub>S [hydrogen sulfide] production and damage to reservoir itself.<sup>87</sup>

Potential hydrogen sulfide production is a public health concern because it is a highly toxic gas.<sup>88</sup> In addition, storing hydrogen in these facilities could result in “a total energy loss of the consumed hydrogen” if there is sufficient sulphate in the wells to cause conversion of the hydrogen into hydrogen sulfide, rendering the extremely expensive-to-produce hydrogen worthless.<sup>89</sup> Researchers at UC Riverside also warn that research on storing hydrogen in depleted gas reservoirs is “still in its early stages” and requires specific analysis of local conditions.<sup>90</sup>

## **VII. THE DRAFT RESULTS DO NOT COMPLY WITH SB 100'S CORE MANDATE AND CREATE A LOOPHOLE FOR FOSSIL-FUELED GENERATION TO CONTINUE THROUGH 2045.**

The Draft Results Workshop slide presentation as well as staff's statement in the workshop indicate that the Joint Agencies erroneously interpret “retail sales” to exclude transmission losses, distribution losses, or the energy to charge utility-scale storage.<sup>91</sup> This misinterpretation violates the letter and spirit of SB 100 and creates a perverse loophole for continued reliance on fossil-fueled generation through 2045. We urge the Joint Agencies to correct this harmful misinterpretation and uphold the integrity of one of the State's most important clean energy laws.

### **A. The Facts, Plain Text, and Legislative History of SB 100 Demonstrate That “Retail Sales” Does Not Exclude Line or Battery Storage Losses.**

SB 100 requires California to plan for “a transition to a zero-carbon electric system.”<sup>92</sup> It states in no uncertain terms that “[i]t is the policy of the state that eligible renewable energy resources and zero-carbon resources supply 90 percent of all retail sales of electricity to California end-use customers by December 31, 2035, 95 percent of all retail sales of electricity to California end-use customers by December 31, 2040, 100 percent of all retail sales of electricity to California end-use customers by December 31, 2045, and 100 percent of electricity procured to serve all state

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<sup>87</sup> UC Riverside, *Final Report: Hydrogen Blending Impacts Study*, p. 15 (Jul. 18, 2022) (“UC Riverside Study”), available at <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF>.

<sup>88</sup> See Agency for Toxic Substances and Disease Registry, *Hydrogen Sulfide – ToxFAQs* (Oct. 2024), available at <https://www.atsdr.cdc.gov/toxfaqs/tfacts114.pdf>.

<sup>89</sup> RAG Austria et al., *Underground Sun Storage: Final Report*, at 6 (Oct. 31, 2017), available at <https://www.rag-austria.at/en/innovation/innovation-projects/underground-sun-conversion>.

<sup>90</sup> R.13-02-008, Notice of Filing of Joint Utilities' Hydrogen Blending Compendium Report, PDF p. 20 (Feb. 14, 2025), available at <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M556/K896/556896659.PDF>.

<sup>91</sup> Draft Results at Slide 19; Workshop Recording at 00:24:10.

<sup>92</sup> Cal. Pub. Util. Code §§ 454.53(a).

agencies by December 31, 2035.”<sup>93</sup> The term “retail sales” includes transmission, distribution, and battery storage losses, and the Joint Agencies’ contrary assumptions are factually incorrect and inconsistent with SB 100.

First, as a factual matter, line and storage losses are not separate from the retail sales, and the power generated and lost is included within retail sales. Indeed, retail sales in California, and throughout the country, include the losses incurred to meet the relevant energy demand. Retail customers pay for transmission and distribution losses in their bills as they are included in the energy requirement to fulfill a particular retail sale. As Independent System Operator (“ISO”) New England describes, line losses are one of the critical components that determines the actual price of the sale.<sup>94</sup> Including line losses in retail sales is consistent with a long line of regulatory decisions because the CPUC scales up marginal energy costs by estimated line losses in general rate cases.<sup>95</sup> For example, in a ratemaking case, the CPUC provided this table:

	PG&E (capped)	TURN (capped)	WMA (capped)	WMA (uncapped)
Base Discount	6.53	6.53	21.43	26.43
Line Loss Adjustment (Add)	1.02	1.02	1.02	1.02
DBA (Subtract)	(5.15)	(5.15)	(5.15)	(5.15)
Net Discount	2.40	2.40	17.30	22.30

As this table shows, line losses are not separate from the retail sales. Rather, they are integral in the sale and the procurement decisions necessary to provide the energy to meet that sale. California ratepayers have been paying for these line losses in their bills, demonstrating that line losses are in no way separate from retail sales.<sup>96</sup>

Second, the text and structure of SB 100 demonstrate that the Legislature did not intend for the agencies to exclude a large percentage of power generation through a line and storage loss loophole. SB 100 is the “100 Percent Clean Energy Act,” not the 85% or 80% Clean Energy Act.

<sup>93</sup> Cal. Pub. Util. Code § 454.53(a).

<sup>94</sup> ISO-New England, *FAQs: Locational Marginal Pricing*, available at <https://www.iso-ne.com/participate/support/faq/lmp#f> (explaining that transmission losses are incorporated into the cost of locational marginal pricing and, ultimately, customer rates).

<sup>95</sup> See, e.g., California Energy Commission, *A Review of Transmission Losses in Planning Studies*, p. 1, available at <https://efiling.energy.ca.gov/GetDocument.aspx?tn=62058> (explaining that general rate cases at the CPUC “scale up marginal energy costs by estimated line losses”).

<sup>96</sup> Federal law also confirms that line losses are included within sales, by requiring Public Utility Regulatory Policies Act of 1978 payments to include line losses because it reflects the costs a utility would have had to pay had they not contracted for the energy from a qualifying facility. See CPUC, Decision 09-05-030, Decision Granting Pacific Gas and Electric Company’s Petition to Modify Decision 01-01-007 (May 2009), available at [https://docs.cpuc.ca.gov/PublishedDocs/WORD\\_PDF/FINAL\\_DECISION/101544.PDF](https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/101544.PDF).

The plain language ties the 100% requirement to procurement, not to the smaller amount of electricity that may enter a customer’s building after a loss. SB 100 requires sellers to “procure a minimum quantity of eligible renewable energy resources for each... compliance period”<sup>97</sup> Utility procurement decisions assume that some energy may be lost when determining how much to procure to meet a certain requirement. That is why retail sales include losses within the sale; it is considered part of the same transaction. In other words, to procure renewable energy that is “equal to an average of 60 percent of the sales,” a retail seller must procure more than the end user needs to account for losses. Inclusion of the “retail sales” language was not meant to exclude this procurement for losses because the language requires procurement “equal” what is necessary to meet those retail sales.

Third, SB 100’s legislative history indicates that the Legislature, when passing SB 100, intended to establish “a new policy which plans for all electricity by December 31, 2045 to be from a mix of both RPS-eligible and zero-carbon resources.”<sup>98</sup> The Senate Floor Analysis also confirms that zero-emissions requirement covers the “remaining electricity procurement,”<sup>99</sup> and it warns that “new assets could be stranded assets in the future if they are powered by fossil fuels.”<sup>100</sup> In other words, the Legislature intended for SB 100 to require all electricity in California be from renewable or zero-carbon generation, not polluting gas plants. Then-Governor Jerry Brown’s SB 100 signing statement further confirms this intent. It summarizes the statute’s goal of ensuring renewables and zero-carbon energy meet “100 percent of the state’s retail electricity supply.”<sup>101</sup> The statement acknowledged that getting to 100% zero-carbon and renewable energy would not be easy, and that the path must focus on increased energy storage, increased efficiency, and demand response.<sup>102</sup> Neither the Legislature nor the Governor contemplated keeping California’s gas fleet online. Rather, their statements underscore that the intent of SB 100 is to “[send] a clear signal to markets to expand clean energy generation”<sup>103</sup> and provide a path for California to lead the world and decarbonize the electric sector. The clear intent of SB 100 is to put California on a path to a renewable and zero-carbon grid, in which gas-fired power plants no longer disrupt the climate.

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<sup>97</sup> Cal. Pub. Util. Code § 399.15.

<sup>98</sup> Senate Rules Committee, *California Renewables Portfolio Standard Program: Emissions of Greenhouse Gases*, p. 4 (Aug. 28, 2018) (emphasis added), available at <https://assets.sourcemediacom/f3/c3/2f01ba3c45d0a2f8819c4c71fb27/201720180sb100-senate-floor-analyses.pdf>.

<sup>99</sup> *Id.*

<sup>100</sup> *Id.*

<sup>101</sup> Governor Brown Letter to State Senate.

<sup>102</sup> *Id.*

<sup>103</sup> *Id.* (emphasis added).

Finally, even CARB in the 2022 Scoping Plan Update, acknowledges that retail sales cannot exclude losses, recognizing that SB 100 covers “[r]etail sales load” not just the amount of retail sales.<sup>104</sup> The “retail sales load” is the total load necessary to fulfill those retail sales, not just a part of it.

For all of these reasons, SB 100 includes line and storage losses. That is the plain meaning and intent of the statute, that is how billing is done, and that is how procurement is performed. We urge the Joint Agencies to correct the legal error in their interpretation of “retail sales” and comply with SB 100.

### **B. The Joint Agencies’ Misinterpretation of SB 100 Creates a Loophole for Fossil-Fueled Generation to Continue through 2045.**

If left uncorrected, this error will have long lasting adverse impacts on Californians’ health. Because the Joint Agencies’ misinterpretation of SB 100 would shrink its coverage to roughly 80% of all electricity generation, the Draft Results indicate that a whopping 90,000 GWh of fossil gas remain online in 2045 under the “SB 100 Only” scenario.<sup>105</sup> This dirty generation will continue to exacerbate California’s air pollution crisis, and because California’s gas plants are disproportionately located in disadvantaged communities, it will impose health burdens on the State’s most vulnerable people. According to PSE Health Energy’s analysis, 100 of 195 gas plants in California are located in communities with the highest CalEnviroScreen scores (CES Scores of 75-100).<sup>106</sup> The Legislature has repeatedly called for solutions to this injustice, directing load-serving entities to minimize localized pollution from electricity generation with an early priority for disadvantaged communities.<sup>107</sup> As noted above, the Legislature has also ordered the CEC and CPUC to develop resource plans that “substantially reduce, no later than 2035, the need to rely on nonpreferred resources [(e.g. gas plants)] in local capacity areas.”<sup>108</sup> Allowing gas plants to remain online in perpetuity defies this direction, stalling California’s clean energy transition.

In sum, the Joint Agencies’ exclusion of line and battery storage storage losses from the SB 100 definition of “retail sales” not only lacks a legal basis, but also poses real threats to California’s

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<sup>104</sup> CARB, *2022 Scoping Plan Update*, p. 75, available at <https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf> (emphasis added).

<sup>105</sup> Draft Report at Slide 44.

<sup>106</sup> Elena Krieger, *California Natural Gas Plant Map: State Demographic Dashboard* [Interactive Tableau dashboard], Tableau Public, available at <https://public.tableau.com/app/profile/elena.krieger/viz/Californianaturalgasplantmap/Statedemographicdashboard> (last visited Mar. 20, 2026).

<sup>107</sup> Cal Pub. Util. Code § 454.52(a)(1)(I) (requiring that load-serving entities must “minimize localized air pollutants and other greenhouse gas emissions, with early priority on disadvantaged communities.”).

<sup>108</sup> Cal. Pub. Util. Code § 454.57(e)(4)(A).

air quality and the health of the State's most vulnerable community members. We urge the Joint Agencies to align the SB 100 report with the letter and spirit of SB 100 and require 100% of California's electricity generation to be renewable or zero-carbon by 2045.

Thank you for considering these comments, and we look forward to continuing working with you through the SB 100 process to plan for California's renewable energy transition.

Sincerely,

Julia Dowell

Katherine Ramsey

Sierra Club

Heena Singh

California Environmental Justice Alliance

Nina Robertson

Sara Gersen

Earthjustice

Shana Lazerow

Communities for a Better Environment