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Engenie comments on CERRO 2026 CCS retrofit accounting and data center load

Additional submitted attachment is included below.



Comments on the 2026 California Energy Resource and Reliability Outlook

Docket No. 21-ESR-01, Resource Planning and Reliability | TN 273044

Dear Commissioners and Staff,

Thank you for the opportunity to comment. The 2026 Outlook's expanded scope, covering emerging loads, long-term capacity expansion and wildfire effects on transmission, is a welcome development. These comments are offered for consideration in future editions and in the related firm zero-carbon resources work on this docket.

By way of disclosure, I developed EMPATHI, an open-methodology framework for estimating the emissions, health and climate consequences of electricity-sector decisions, and I operate Engenie, an independent consultancy. These comments do not take a position on whether any resource should be built. They concern how resources' consequences are counted.

1. Carbon capture retrofits of existing gas plants

The capacity expansion analysis treats carbon capture retrofits of existing combined cycle plants as the lowest-priced firm zero-carbon technology (p. 5). They are the only emerging resource the model selects before 2040 (p. 63), and the Base scenario retrofits about 10 GW, roughly half the existing combined cycle fleet (p. 64). Retrofits are modeled at 95 percent capture, with 95 percent of their generation counted toward SB 100 (p. 58, note 73). I recognize the report states this follows the 2025 SB 100 Report convention and that the SB 100 process is not a venue for determining compliance.

The convention measures capture at the stack. A retrofitted plant continues to burn gas, and three consequences of that sit outside a stack-based accounting.

First, upstream emissions. Producing, processing and transporting the gas releases methane before it reaches the plant, beyond the reach of capture at the plant. Nearly 90 percent of the gas used in California is imported, and CARB estimates the out-of-state releases and flaring associated with that gas at 7.2 MMT CO₂e on a 100-year basis and 19.5 MMT CO₂e on a 20-year basis for 2023 (CARB, 2025). CARB notes these emissions are not included in the state inventory or factored into in-state targets, and that its estimate rests on the U.S. EPA inventory, which measurement-based studies have found to understate oil and gas methane. One such study puts U.S. supply-chain methane at about 2.3 percent of gross production, roughly 60 percent above the inventory estimate of the time (Alvarez et al., 2018).

Without capture, these upstream emissions are smaller than the plant's stack carbon dioxide on a 100-year basis, and comparable to it on a 20-year basis at measurement-based loss rates (Alvarez et al., 2018). With 95 percent capture, they become the larger term at both horizons. Even on CARB's inventory-based estimate, upstream emissions expressed in carbon dioxide equivalent (CO₂e) exceed the plant's residual stack carbon dioxide, by roughly 1.4 times using 100-year global warming potentials and roughly 3.6 times using 20-year potentials. At measurement-based estimates of supply-chain loss, the multiple rises to roughly five times or more on a 100-year basis and more than ten times on a 20-year basis. Reporting both horizons is useful because the 100-year metric is the conventional accounting basis, while the 20-year metric makes the near-term forcing from methane visible.

The CARB-based figures use the EPA combustion emission factor for natural gas of 53.06 kg CO₂ per MMBtu and EPA's heat-content factor of 0.001026 MMBtu per standard cubic foot, with CARB's 2023 estimate converted from AR4 to the AR6 fossil methane potentials of 29.8 for 100 years and 82.5 for 20 years (IPCC, 2021). The measurement-based figures are approximate, since published loss rates vary by study and basin. CARB notes its estimate excludes fuel combustion within the supply chain, such as compressor engines, so these figures understate total upstream emissions.

Second, capture consumes energy. The 2024 ATB retrofit cases underlying the report's CCS cost assumptions supply the capture system's thermal and electrical requirements from the host plant, so the penalty appears as reduced net output and a higher heat rate (NREL, 2024; Schmitt et al., 2023). The Outlook does not state the heat-rate assumption used for retrofits in the capacity expansion model. Documenting whether modeled retrofit performance carries this penalty through to fuel use per delivered MWh would clarify the comparison, and any higher gas throughput would raise upstream emissions in proportion.

Third, carbon capture does not by itself eliminate nitrogen oxides or other combustion-related emissions at the host plant. SB 423 calls for the assessment of firm zero-carbon resources with an emphasis on reducing emissions of greenhouse gases, toxic air contaminants and criteria air pollutants (p. 12). Those consequences are not reported alongside the cost and resource-build comparisons in this Outlook, although in the Base scenario retrofitted plants generate throughout the year (p. 66).

Taken together, the 95 percent treatment of CCS retrofits reflects capture at the plant and does not make upstream fuel-cycle emissions visible in the resource comparison. At every upstream emission rate examined here, those emissions exceed the residual stack carbon dioxide after capture. Including them on a CO₂e basis may materially change the climate comparison with candidates that do not depend on continued fuel combustion, such as enhanced geothermal or long-duration storage, while the air quality dimension remains unreported.

Recommendation: In future capacity expansion work, report the climate implications of gas with CCS using an accounting boundary that makes upstream fuel-cycle emissions explicit, alongside the existing stack-based treatment, at both 20-year and 100-year horizons. Document the retrofit heat-rate assumption so that fuel use associated with capture is reflected consistently. Where a selected resource continues combustion, report criteria air pollutant and toxic air contaminant consequences alongside cost and reliability results, consistent with SB 423.

2. Load growth and quantifying the value of flexible and clean operation

The Outlook forecasts statewide peak demand rising from about 61 GW in 2026 to 83 GW by 2045, with emerging loads including data centers, hydrogen and agricultural electrification (p. 40). Data centers are the most developed example: peak demand rising from about 930 MW to approximately 5,800 MW under the Planning Forecast and 8,300 MW under the Local Reliability Scenario by 2040 (p. 47), reaching roughly 9 to 11 percent of California ISO peak (p. 48). The dedicated forecasts and hourly profiles developed from interval meter data provide a strong foundation for understanding how new load interacts with California's electricity system.

The Outlook identifies flexible data center operation as an opportunity to reduce the system effects of new large loads (p. 49), while noting that publicly available information does not yet quantify the grid effects of flexibility contracts (p. 50). The same opportunity applies across emerging loads, and the incremental system emissions attributable to individual components of forecast load growth are not separately reported. Extending the analysis to distinguish among operating and procurement strategies could help planners identify which approaches best support reliability and decarbonization, while giving customers credit for choices that improve system outcomes.

Growth of this size affects both dispatch and long-term resource development, so its system effects depend on more than annual electricity consumption. Load shape, flexibility, incremental clean-energy procurement, storage and on-site resources can each change what generation is needed and when.

Not all load growth has the same emissions character. Electrification loads, such as EV charging and agricultural electrification, can replace fuel combustion elsewhere, so where they do, their net effect includes both the grid emissions associated with serving the new load and the end-use combustion displaced. New loads such as data centers add demand without the same displaced-combustion term. A comparison that reports only grid emissions would therefore understate the benefits of electrification in those cases.

For data centers, the forecast also discounts projects expected to rely primarily on on-site generation (p. 45). Better characterization of these resources would allow the forecast to distinguish among approaches with different reliability, emissions and grid implications.

Recommendation: In future Outlooks, compare otherwise consistent planning cases with and without major components of forecast load growth, and with variants reflecting flexible operation, incremental clean-energy procurement, storage and on-site resources where data permit. For electrification loads, net the end-use combustion they displace. Report the resulting differences in resource build, system emissions, and air quality and associated health outcomes. Hourly marginal emission rates applied to existing load profiles could supplement the planning analysis for near-term operating effects. This would give planners and customers a clearer view of which strategies provide the greatest system benefit.

Respectfully submitted,

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Methods and data availability

The EMPATHI methodology is published under a CC BY 4.0 licence at <https://doi.org/10.5281/zenodo.21347959>. I would be glad to share the calculations underlying these comments with staff.

References

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