BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking on California Advanced Electric Rate Design.	Rulemaking 26-04-009

JOINT INVESTOR-OWNED UTILITY PROPOSAL OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), PACIFIC GAS AND ELECTRIC COMPANY (U 39 E), AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E) ADDRESSING THE REQUIREMENTS OF ASSEMBLY BILL 2109

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Pursuant to the September 3, 2026 Administrative Law Judge's *Ruling Directing Joint Investor-Owned Utilities Proposal on Assembly Bill 2109 Requirements* (ALJ Ruling) and the Administrative Law Judge's September 28, 2026 *Email Ruling*, Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E) (collectively, "Joint IOUs") respectfully submit their joint investor-owned utility proposal addressing the requirements of Assembly Bill 2109 (Joint IOU Proposal) to the California Public Utilities Commission (Commission).

I.
INTRODUCTION

Assembly Bill (AB) 2109 (Carillo, September 27, 2024), codified in Public Utilities Code Sections 371 and 451.7, is intended to help reduce emissions from energy and carbon-intensive process heat production in the industrial sector.[1] The law facilitates industrial process heat recovery (IPHR) by exempting qualifying projects from certain nonbypassable charges (NBCs) that would otherwise apply, up to 25% of customer load departing the system, for customers with a minimum of 500kW per project. In doing so, the Legislature also recognized the potential for

[1] August 28, 2024 Assembly Floor Analysis (*available at* https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=202320240AB2109).

costs to shift to other customers and directed the Commission to establish what NBCs the exemption should apply to as well as a cap on the load subject to the exemption.

The Joint IOUs have developed a practical proposed implementation framework for AB 2109 that balances the goals of facilitating IPHR improvements while protecting other customers from undue cost shifts. AB 2109 presents the Commission with a series of foundational policy choices that will determine both the scope of the rate component exemptions and its impact on all customers. The statute does not prescribe a specific list of eligible NBCs, nor does it establish a specific participation cap or sunset period. Instead, the Legislature expressly granted the Commission discretion to define the applicable "nonbypassable or departing load surcharges" and to establish a cap on exempted load. The legislative history further confirms that this language was adopted to provide the Commission with flexibility in implementation while limiting cost impacts on other customers.

Accordingly, the Commission's primary task in this proceeding is not merely administrative implementation of the statute, but the exercise of policy judgment in four key areas: (1) determining which nonbypassable charges should be considered eligible for bypass under AB 2109; (2) establishing a reasonable participation cap; (3) determining how the cost shifts caused by the exemption should be allocated among customers; and (4) developing practical enrollment, verification, and ongoing compliance procedures to ensure that only qualifying customers receive the benefit. The Commission's decisions in these areas should be guided by the Legislature's explicit direction to minimize cost impacts on nonparticipating customers while enabling deployment of qualifying IPHR technology.

The Joint IOUs believe these policy determinations should to the extent possible continue to be grounded in well-established principles of rate design, including affordability and equitable cost allocation. When an exemption from otherwise applicable costs reduces collections without reducing the underlying cost or obligation, the unrecovered amount is shifted to other customers. The Commission should carefully limit the charges eligible for exemption to those charges that are most consistent with the intent of AB 2109 and exclude charges from the exemption

associated with certain fixed obligations, including securitized wildfire-related charges. Likewise, the Joint IOUs believe costs resulting from the exemption should be recovered broadly from all customer classes, including residential customers, rather than be concentrated on a narrower subset of customers, as any potential decarbonization benefits of IPHR will accrue to all customers. For these reasons, the Commission should adopt a reasonable participation cap that advances the Legislature's objectives without creating undue cost shifts or unduly increasing affordability burdens on households and other nonparticipating customers. A balanced approach will encourage adoption of qualifying technology while fulfilling the Commission's concurrent obligation to protect customers who ultimately fund the exemption.

II.

THE STATUTORY LANGUAGE EXPRESSLY DELEGATES DEFINITIONAL AUTHORITY TO THE COMMISSION

The Legislature clearly delegated to the Commission the authority to define the type of nonbypassable or departing load surcharges for which eligible IPHR technology should be exempted.

Section 451.7(a) of the Public Utilities Code states, in relevant part: "Nonbypassable or departing load surcharges, *as defined by the commission*, shall not apply ..." to reduced electricity use due to IPHR technology. (Emphasis added). The emphasized language evidences a clear intent for the Commission to determine which NBCs or departing load surcharges should not apply to the eligible IPHR technology.

Subsection (c) of Section 451.7 further reinforces the Legislative intent by directing the Commission to minimize the cost shift to other customers in its implementation of subsection (a). The Commission would be unable to influence the costs associated with the legislation if the legislation required specific NBC or surcharge exemptions.

Had the Legislature intended an automatic exemption from all existing NBCs, it would have simply referenced all Commission-approved nonbypassable charges. It did not do so.

The inclusion of the phrase "as defined by the commission" demonstrates clear legislative intent to provide implementation flexibility.

A. The Commission Should Narrowly Define Nonbypassable Charges for the Purpose of Implementing AB 2109

The ALJ Ruling directs the IOUs to identify: "a list of nonbypassable charges that IPHR customers should *and should not* be exempt from and a justification for each" (emphasis added). Table 1, below, provides a summary list of potential NBCs. The IOUs provide a comprehensive list of potential NBCs and current associated rate values, with detailed charges provided in the appendix.

The Joint IOUs propose the following:

- Public-purpose or programmatic charges should be considered exempt NBCs because they are most closely related to the type of energy-efficiency load reduction contemplated by AB 2109.
- Securitized wildfire charges should not be considered exempt NBCs because they fund preexisting fixed obligations owed to third-party bondholders, because approved wildfire-related costs should remain the obligation of all customers, and because exempting them would create unjustified cost shifts to nonparticipants.

Table 1 – List of Potential NBCs for Consideration[2]

	SCE	PG&E	SDG&E
1. Public Purpose Program Charge (PPPC)	$0.02159/kWh	$0.02082/kWh	Pure Energy $0.01840/kWh Demand + Energy Demand = $0.02/kW Energy = $0.01834
2. Nuclear Decommissioning	$0.00003/kWh	-$0.00002/kWh	$0.00000
3. Wildfire Non-Bypassable Charge	$0.00591/kWh	$0.00591/kWh	$0.00591/kWh
4. Competition Transition Charge	$0.00002/kWh	$0.00024/kWh	Pure Energy ($0.00007)/kWh Demand + Energy Demand = ($0.02)/kW Energy = $0.00000
5. Power Charge Indifference Adjustment[3]	$0.01868/kWh	$0.01902/kWh	$0.01955/kWh
6. Total wildfire bond charges or securitized costs	$0.00507/kWh	$0.00171/kWh	$0.00000 (DWR-BC)

B. Securitization & Wildfire Fund Charges are Distinguishable From Traditional NBC's and Should Not Be Exempt From Payment

The IOUs recommend that securitization charges (Categories 3 and 6,[4] above) not be treated as exemptible NBCs under AB 2109, including:

- Fixed Recovery Charges (FRC);
- Wildfire Hardening-related securitization charges; and

[2] Figures reflect the following effective rates: PG&E = 03/01/2026, and SDG&E = 8/1/26, SCE values from 2027 Energy Resource Recovery Account Forecast of Operations, October Update. A.26-05-006, October 26, 2026.

[3] PCIA figures reflect the following: PG&E = represents the average direct access rate from 2027 Energy Resource Recovery Account Forecast (A. 26-05-007) Fall Update, SDG&E = Represents the class average PCIA rate for Medium/Large C&I reflecting rates effective 8/1/26. SCE PCIA values from 2027 Energy Resource Recovery Account Forecast of Operations, October Update. A.26-05-006, October 26, 2026

[4] For PG&E, these include Wildfire Hardening Charge, Wildfire Hardening Fixed Recovery Charge Balancing Account, Recovery Bond Charge, Fixed Recovery Charge Balancing Account, and Recovery Bond Credit.

- Wildfire Recovery Bond Charges;

These charges are materially different from traditional public-purpose or policy-program charges because they exist to satisfy legally binding obligations incurred through Commission-approved financing structures and are not owed to a utility, but rather to a third party. Under securitization statutes and associated financing orders, investors purchase bonds in reliance on dedicated revenue streams.[5] The charges are imposed to repay bondholders rather than to fund ongoing utility programs or public policy initiatives.

As a result, allowing certain customers to avoid these charges would not in any way reduce the underlying obligation. Instead, the unrecovered revenue would necessarily be shifted to other customers and/or require modification of the recovery mechanism, potentially undermining the foundational assumptions underlying the securitization authorization. The IOUs respectfully recommend the Commission therefore reasonably determine that these charges are outside the class of charges that should be exempted under Section 451.7.

The Joint IOUs propose that AB 2109 customers continue to pay for NBCs that are collected by IOUs for remittance to non-IOU entities. The IOUs have multiple Commission-authorized NBCs from customer generation departing load related to wildfire costs that are directly remitted to other entities, including Special Purpose Entities (SPEs) and the California Department of Water Resources (DWR). While the IOUs collect these NBCs from customers in the manner directed by Commission decisions, the IOUs do not have legal title to the amounts collected and are obligated to remit the NBCs it collects to other entities. These NBCs fall into two general categories: (1) NBCs authorized by Financing Orders issued by the Commission pursuant to Article 5.8 of the California Public Utilities Code and remitted to SPEs pursuant to Financing Orders (Financing Order NBCs); and (2) Wildfire Fund Charges authorized by

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[5] *See* Cal. Pub. Util. Code §§ 850(b)(7), 850.1(b) (defining fixed recovery charges as "nonbypassable" charges authorized through a Commission financing order and providing that such charges "shall be irrevocable," subject to statutory true-up adjustments). These statutory protections create the dedicated revenue stream supporting securitized obligations purchased by third-party investors, materially distinguishing fixed recovery charges from traditional utility public-purpose or policy-program charges.

Commission Decisions and remitted to the Department of Water Resources (Wildfire Fund Charge NBCs).

1. PG&E and SCE Financing Order NBCs

PG&E's Financing Order NBCs result from multiple Commission Financing Order decisions authorizing the issuance of securitized bonds (Recovery Bonds) pursuant to AB 1054, which is codified at Chapter 4, Article 5.8 of the California Public Utilities Act. First, Decision (D.)21-05-015 authorized PG&E to issue up to $7.5 billion of recovery bonds to fund costs and expenses related to 2017 North Bay Wildfires and other financing costs. Next, D.21-06-030 granted PG&E's request to issue approximately $1.2 billion in Recovery Bonds by a legally separate SPE for the purpose of fire risk mitigation plan capital expenditures. Finally, D.24-02-011 authorized a PG&E request for the issuance of approximately $1.421 billion in Recovery Bonds by a legally separate SPE for the purpose of additional fire risk mitigation plan capital expenditures (collectively, the "PG&E Financing Order Decisions").

The PG&E Financing Order Decisions authorize PG&E to collect NBCs recovering FRCs in amounts sufficient to cover debt service on the Recovery Bonds, as well as the cost of servicing the Recovery Bonds, and certain tax amounts (collectively, the "Financing Order NBCs").[6] PG&E does not have right, title, and interest in the NBCs; these were sold or assigned to SPEs for use in securing the Recovery Bonds.[7] As directed in the PG&E Financing Order Decisions, PG&E remits the NBC revenues directly to the SPEs.

D.21-05-015 approved a 30-year plan through which all existing and future non-CARE and non-FERA PG&E customers repay the principal and interest due on the bonds through the NBCs.[8] Except for municipal departing load, if customers no longer take transmission and

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[6] *See* D.21-05-015, p.12.
[7] D.21-05-015, COL 28; D.21-06-030, COL 24; D. 24-02-011, COL 24.
[8] D.21-05-015, COL 16 and COL 58.

distribution retail service from PG&E after the date of the issuance of the decisions, they nonetheless remain obligated to continue to pay the NBCs.[9]

SCE's Financing Order NBCs similarly arise from multiple Commission financing orders authorizing the issuance of Recovery Bonds pursuant to AB 1054. The Commission first authorized SCE's issuance of $337.1 million of Recovery Bonds in D.20-11-007 to finance certain fire risk mitigation capital expenditures. The Commission subsequently issued D.21-10-025, authorizing Recovery Bonds to finance approximately $517.6 million of additional fire risk mitigation capital expenditures. SCE thereafter obtained a third Financing Order, D.23-02-023, of approximately $772.4 million.

The SCE Financing Orders establish a financing structure under which Recovery Bonds are supported by a nonbypassable FRC. The right to receive revenues from the FRC constitutes Recovery Property that is transferred to a legally separate, bankruptcy-remote SPE, which issues the Recovery Bonds. The FRC is adjusted through a Commission-approved true-up mechanism to ensure timely recovery of amounts sufficient to pay debt service on the Recovery Bonds and other ongoing financing costs. The Commission has continued to employ this same basic structure in SCE's subsequent wildfire securitizations, including its financing orders for Thomas and Woolsey claims, D.25-08-033 and D.26-05-006, respectively.

PG&E's and SCE's obligations prohibit them from taking any action that would limit or alter the NBCs or any rights set forth under the Financing Order ().[10] Likewise, the statutory framework governing these NBCs, includes the "State Pledge" under which California committed that it will not take actions that will limit, alter, or impair the collection of the fixed recovery charges until the recovery bonds have been paid in full. (*See* PU Code Section 850.1 (e)).

Consistent with these financing orders and the State Pledge, the regulatory framework applicable to the Financing Order NBCs should remain undisturbed. Importantly, revenues from

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[9] *See* D.21-05-015, COL 24, COL D.21-06-030, COL 12; D.24-02-011, COL 12.
[10] *E.g.*, D.21-05-015, COL 22.

Financing Order NBCs are not utility revenues. Rather, the utilities act in substance as the servicer and collection agent for these charges, collecting FRC revenues from customers for the benefit of the SPE and the Recovery Bond holders.

Nothing in AB 2109 requires the Commission to alter the revenues available to SPEs or regulatory framework established for the issuance of Recovery Bonds. Nor does AB 2109 alter the State Pledge or the customers responsible or the NBCs. Creating an exemption would do precisely what the framework is designed to avoid: it would remove customers from the base supporting the Recovery Bonds and thereby alter the revenue stream underlying the recovery property. Such a change would affect revenues committed to a legally separate SPE, rather than merely changing revenues available to SCE, and would be inconsistent with the financing structure approved by the Commission.

Accordingly, AB 2109 customers should continue to pay Financing Order NBCs. Revenues from these charges are committed to the SPEs and Recovery Bondholders. Any exemption would reduce the amounts collected and remitted under the Financing Orders, alter the recovery mechanism supporting the bonds in conflict with both the Financing Orders and the governing statutory framework, including the State Pledge.

2. AB 2109 Customers Should Continue to Pay Wildfire Fund Charges

The Joint IOUs also collect from customer generation departing load customers the Wildfire Fund Charge (WFC), a nonbypassable charge established pursuant to AB 1054 and implemented by D.19-10-056 and D.20-07-014, and multiple successor decisions determining the NBC revenue requirement and rate. The objective of this previous legislation was to reduce wildfire risks while establishing a system to appropriately spread the exposure IOUs have for liabilities from wildfires. D.19-10-056 adopted a rate agreement between the Commission and DWR, "structured to ensure that the revenue requirement for the Wildfire Fund NBC is

determined based on historic contributions from the ratepayers of the electrical corporations that participate in the Wildfire Fund."[11]

In authorizing the WF NBCs, the Commission maintained the structure in place for exemptions under a predecessor DWR Bond Charge under which the Joint IOUs imposed WF NBCs on the category of customer generation departing load at issue here.[12] The Commission subsequently approved servicing orders governing the collection and remittance of the NBCs through D. 20-07-014.

Critically, just like the revenues discussed in the previous section, revenues collected through the WF NBCs are not utility revenues. The charge is collected by the Joint IOUs and directly remitted to DWR and is DWR property for all purposes under California law. The servicing orders adopted by the Commission clarify that WF NBCs are DWR revenues, and that all DWR revenues constitute property of DWR.[13] The Joint IOUs act as agents for DWR and collect and remit to DWR the proceeds of the WF NBC. As the Commission recently explained, this structure assures that those monies will be available to carry out the uses outlined in AB 1054.[14]

Extending an AB 2109 exemption to the WF NBCs would directly reduce the revenues collected and remitted to DWR and would alter the recovery mechanism approved by the Commission to support the Wildfire Fund. Unlike charges established to recover utility costs, WF NBCs are DWR property and are dedicated to fulfilling the statutory objectives of AB 1054. Neither AB 1054 nor D.19-10-056 authorized exemptions beyond those already retained from the predecessor DWR Bond Charge framework. The Commission therefore should not expand the existing exemption structure in a manner that reduces the load responsible for funding the

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[11] D.19-10-056, p. 17.
[12] *See* D.19-10-056, p. 28.
[13] D.20-07-014, OP 1 (adopting Servicing Orders attached to May 6, 2020 Email Ruling, *available at* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M336/K533/336533795.PDF).
[14] D.24-12-001, p. 2; D.;25-12-006, p. 3.

Wildfire Fund and diminishes revenues remitted to DWR. Accordingly, the Joint IOUs recommend that the WF NBCs remain outside the scope of any AB 2109 exemption.

III.

A PROGRAM CAP BASED ON 50% OF THE ESTIMATED CURRENT MARKET SIZE IS REASONABLE

The Joint IOUs recommend that any program cap be established in megawatts (MW) rather than by customer count. A MW-based cap is transparent and directly aligns the cap with the size of the potential subsidy being provided. Because the exemption is tied to reductions in grid consumption, a MW cap enables the Commission to monitor and evaluate the magnitude of exempted load and associated cost shifting over time. By contrast, a customer-count cap could result in significantly different subsidy levels depending on the size and energy consumption of participating customers and could allow total exempted load to expand substantially without a corresponding limit on cost impacts. A customer-count approach would also create administrative complications because some eligible customers maintain multiple accounts across several premises.

A MW-based cap is also consistent with existing Commission practice in other programs, including Direct Access, where participation limits are established using load-based metrics rather than customer counts. In addition, the statutory eligibility requirements themselves support a load-based framework. Because AB 2109 limits qualifying generation to no more than 25 percent of a customer's peak electrical load and requires a minimum technology size of 500 kW, a customer would generally need a peak load of at least 2 MW to meet the statutory eligibility requirements. For these reasons, a MW cap provides the Commission with the most effective mechanism for balancing program participation with its statutory obligation to minimize cost impacts on nonparticipating customers and to monitor the overall size of the subsidy over time.

To develop a reasonable program cap, the Joint IOUs first sought to estimate the market size of potential customers capable of deploying qualifying IPHR technology. Rather than beginning with an arbitrary cap value, the Joint IOUs developed a market-based methodology that identifies customer segments most likely to satisfy the statutory eligibility requirements. Using existing customer load data and industry classifications associated with manufacturing processes capable of supporting IPHR technology (North American Industry Classification System (NAICS) codes), the analysis focused on large industrial customer accounts in sectors such as steel, glass, and concrete production with demand levels sufficient to support installation of qualifying equipment (>2MW of underlying customer demand, as 25% of load would meet the minimum criteria of 500kW). Based on this methodology, the following table provides a preliminary estimate of the total MW levels in each service territory for estimated eligible current customers that could take advantage of the AB 2109 exemption.

Table 2 – Estimated Eligible IPHR MWs From Heavy Industries (such as Steel, Glass, and Concrete, Assuming > 2MW Each)

IOU	Estimated Underlying Customer Capacity (MW)	Estimated IPHR Capacity (MW)	Capped IPHR Capacity (MW) at [50%]
SCE[15]	***	***	***
PG&E	96	24	12
SDG&E	0	0	0

The Joint IOUs believe it is reasonable to place a cap at 50% of the overall potential market size estimated to be capable of participating under this statute. This cap can be revisited, if necessary, in the future by the Commission. For ease of implementation, the IOUs believe this should be an IOU-specific cap – i.e.,12 MW for PG&E. Given SDG&E does not have any estimated AB 2109 eligible current customers, SDG&E's cap should be 0 MW. This approach would allow for participation across both PG&E's and SCE's service territories instead of, for

[15] SCE is not providing its estimated MW cap as calculated based on the methodology described above out of concern for violating the Commission's 15/15 Rule. SCE will further consider ways to provide its cap consistent with the 15/15 Rule. The methodology described above, and the specific MW cap identified for PG&E, provide sufficient information for the Commission to adopt the Joint IOUs proposed cap methodology.

example, the potential for customers in SCE's territory to take advantage of the full cap, leaving no potential for PG&E customer participation.

IV.

THE JOINT IOUS' PROPOSAL MINIMIZES COST IMPACTS TO NONPARTICIPANTS, AS REQUIRED BY AB 2109

Public Utilities Code Section 451.7(c) states:

> In implementing the exemption in subdivision (a), the commission shall minimize the cost impacts to all nonparticipating customers that are directly attributable to the nonbypassable or departing load charges of customers using industrial process heat recovery technology pursuant to subdivision (b).

The IOUs' proposal complies with this provision and minimizes cost impacts to nonparticipating customers by including a limited number of NBCs and departing load surcharges exemptions, a cap on the number of customers eligible for approved exemptions, and a reasonable sunset on the approved exemptions. Utilizing the above volumetric costs-per-kWh of the NBCs, PG&E and SCE evaluated the potential customer accounts that may take advantage of the subsidy to determine the potential size of the annual subsidy:

Table 3 – Total Potential Estimated Cost Shift – Pacific Gas & Electric Company

	$/kWh	100% Participation – 24 MW	Proposed 50% Cap – 12MW
All NBCs	$0.04784	$18,180,421	$9,090,211
NBCs less WF NBCs	$0.04021	$15,278,696	$7,639,348

Table 4 – Total Potential Estimated Cost Shift – Southern California Edison Company

	$/kWh	100% Participation	Proposed 50% Cap
All NBCs	$0.05130	$16,544,925	$8,272,462
NBCs less WF NBCs	$0.04032	$13,003,730	$6,501,865

Table 5 – Impact of Potential Cost Shift – JIOU Proposal - SAR

	Estimated Cost Shift ($M)	System Avg Rate Impact
PG&E	$7.639	0.038%
SCE	$6.501	0.032%

Table 6 – Impact of Potential Cost Shift – Rates & Monthly Bills

Impact ($/kWh)	PG&E	SCE
System Average Rate[16]	$0.00010	$0.00008
Res. Average Rate	$0.00010	$0.00008
Average Res. Bill Impact/ Mo (x 500kWh/mo)	$0.05	$0.04

The Joint IOUs believe the cap described above and associated subsidization for the IPHR industry and customers satisfies the legislative objectives of AB 2109. Additionally, to the extent other stakeholders in this proceeding advocate for increased/expanded benefits within the framework of AB 2109, the Joint IOUs strongly urge the Commission to exercise caution, as doing so would result in further cost shifting and detriments to nonparticipating ratepayers.

Related to this, the Joint IOUs note that the intended subsidization of AB 2109 should not be viewed in isolation, but rather in the context of the broader benefits already being provided to this specialized customer group. For example, the federal government has already provided significant support for decarbonizing energy-intensive industries through the Department of Energy (DOE). Additionally, subject to meeting certain eligibility criteria, qualifying IPHR investments may be eligible for the Clean Electricity Credit under Section 48E – which may yield an investment tax credit (ITC) equivalent of up to 30% (or possibly 50%).[17]

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[16] The Joint IOUs acknowledge the ALJ Ruling directing this proposal, among other things, "should include….analysis of estimated rate and bill impacts to illustrate the potential cost shift to non-participants segmented by customer class." However, providing system average and residential average rate impacts delineated further by non-residential customer class would not provide a meaningful difference across each group compared to the system average rate. September 3, 2026 ALJ Ruling, p. 3.

[17] *See* Internal Revenue Service Clean Electricity Credit (https://www.irs.gov/credits-deductions/clean-electricity-investment-credit).

A. Costs Shifts Associated with AB 2109 Should Be Isolated By Utility Service Territory

As the Joint IOUs have proposed a cap specific to each IOU, it is appropriate and administratively preferable for each IOU to support the subsidy created in its own service territory. Doing so at a statewide level would introduce significant, unnecessary and unjustified complexity, increased implementation costs, and potentially raise legal and other fairness issues.

B. New NBCs and Future Securitizations Should Not Be Exempt

The Joint IOUs propose that the Commission limit AB 2109 exemptions to NBCs in effect as of the date of the Commission's decision in this proceeding. The cost shift should not be allowed to grow as a result of any new or future NBCs, which could eventually grow to a level that was not intended by the Commission or Legislature. As further securitization nonbypassables are likely to be considered in the future, which would be intended to be paid by a majority of other customers, the Joint IOUs recommend the Commission not allow for future exemptions, which could not have been anticipated by the Legislature when it enacted AB 2109.

The Joint IOUs' proposal is reasonable because AB 2109 requires the Commission to consider the impact of any exemptions on non-participating customers. Specifically, Section 451.7(c) requires that the Commission "minimize the cost impact of non-participating customers are directly attributable to the nonbypassable or departing load charges of customers [using heat process recovery]." By limiting exemptions to those NBCs that are currently known, the Commission can discharge this duty. Tables 2 through 6, above, show estimated rate and bill impacts to illustrate the potential cost shift to non-participants as required by the ALJ Ruling. However, if the Commission were to exempt customers from *future* NBCs, the Commission could not evaluate the impact to non-participating customers, and arguably would not constitute a just and reasonable ratesetting process. Thus, the Joint IOUs recommend limiting any exemptions to those examined in this Rulemaking.

C. The Cost Shift Can Be Contained if NBC Exemptions and Technology Eligibility Are Not Expanded

The Joint IOUs believe the most effective strategy for minimizing cost impacts on nonparticipating customers is to maintain clear and reasonable limits on both the scope of the exemption and the population eligible to receive it. AB 2109 establishes a narrow exemption directed toward a specific technology and a specific class of industrial customers. The statute does not create a broad policy of making nonbypassable charges generally bypassable, nor should the Commission interpret it as such. To the contrary, NBCs exist to ensure that certain costs approved by the Commission are recovered from all applicable customers. Consistent with AB 2109's statutory language, the Commission should A) limit eligibility to the industrial process heat recovery technologies expressly identified in Section 451.7, B) decline requests to expand the exemption to other technologies, customer classes, or use cases that were not contemplated by the Legislature, and C) avoid future increases to the cap established and approved in this proceeding. Taking these actions and maintaining a narrow technology definition and customer eligibility criteria will help ensure that the subsidy remains targeted and that cost shifting to nonparticipating customers remains limited while incentivizing IPHR applications as intended by the Legislature.

The Commission can further protect customers by establishing a fixed list of eligible nonbypassable charge exemptions at the outset of the program and limiting the exemption solely to those charges identified in this proceeding without any possibility of expanding the fixed list. Any future nonbypassable charges authorized by the Commission should not become exempt under AB 2109. This approach provides certainty regarding the size of the subsidy, prevents unintended expansion of the exemption over time, and preserves the fundamental purpose of nonbypassable charges and finally aligns with Governor Newsom's Executive Order N-5-24 (i.e., the primary objectives of curbing rising electricity costs and providing electric bill relief.) In addition, participating customers should be subject to periodic recertification, such as every

three years, supplemented by ongoing utility monitoring and selected site verification as determined by each IOU, and tracking through existing customer management systems. Regular renewal requirements will help ensure that customers continue to satisfy the statutory eligibility criteria and that the Commission retains visibility into program participation, subsidy levels, and associated customer impacts. Collectively, these safeguards will enable the Commission to implement AB 2109 while fulfilling its statutory obligation to minimize cost impacts on nonparticipating customers.

The IOUs further propose a reasonable 10-year sunset on IPHR exemptions as an additional safeguard for minimizing cost impacts on nonparticipating customers. Establishing a sunset on any approved exemptions would satisfy the legislative intent to provide support for IPHR technology as it seeks technological maturity, while avoiding indefinite benefits with long-lasting cost shifts.

V.

TECHNOLOGY ELIGIBILITY REQUIREMENTS SHOULD BE CLEARLY ENUMERATED, IN COMPLIANCE WITH PUBLIC UTILITIES CODE SECTIONS 451.7 (A) AND (B)

The Joint IOUs believe that all the eligibility requirements enumerated in the legislation be adhered to with no exceptions, as no exceptions are provided in the legislation. The Joint IOUs propose to develop a self-attestation checklist to be made available to applicants wishing to benefit from the provisions of AB 2109. The checklist would serve as the initial technical screen to validate an applicant's eligibility under the requirements enumerated in AB 2109. Applicants not meeting all the prescribed requirements will be notified of their ineligibility and the reason for said ineligibility. A validation process is explained below in Section 6.

The eligibility requirements in the legislation are as follows:

1. The recovered industrial process heat must be integral to the industrial process.
2. The heat must be created by the industrial process.

3. No supplemental firing or fuel use is allowed to increase or stabilize steam temperature.
4. The generated electricity must have zero marginal greenhouse gas emissions.
5. The electricity must be fully self-consumed onsite during manufacturing.
6. The electricity must not be exported to the grid for wholesale sale.
7. The generated electricity must not exceed 25% of the customer's peak electrical load at installation.
8. The technology must have a minimum nameplate rating of 500 kilowatts.
9. The technology must be installed on or after January 1, 2024.[18]

Only customers that satisfy the above requirements should be eligible for exemption of the defined departing load NBCs, subject to availability of the cap.

VI.

A REASONABLE VALIDATION PROCESS SHOULD BE USED TO ENSURE THE INTEGRITY OF THE PROGRAM AND COMPLIANCE

Because the program will include a cap, there may be a possibility of more interest in the program than there is capacity available to satisfy all applicants. To manage this situation, the Joint IOUs propose a deliberate process of "first in first out," with specific criteria for successful reservation of generator capacity eligible for AB 2109 exemptions.

The process starts with the applicant completing an IPHR checklist for generators installed after January 1, 2024. This will screen applicants as they must demonstrate good faith by producing documentation securing an IOU-approved capacity eligible for AB 2109 exemption. The Joint IOUs propose documentation be provided to authenticate intent in participating in AB 2109 exemption. Examples of documentation can include:

[18] Section 451.7(b).

1. Current (or proposed) piping and instrument (P&ID) diagram for your industrial process heat recovery.
2. Current (or proposed) electrical single line diagram for your industrial process heat recovery.
3. Any purchase orders or any financial transactions/receipts for this industrial process heat recovery project.

Once the requested documentation is submitted, reviewed and approved, and capacity is still available, the IOU will issue formal acceptance. This formal acceptance guarantees the approved capacity will be reserved for a period not to exceed 24 months from the date of approval of the checklist. If the 24-month period expires and the generator has not been issued a permission-to-operate, then the applicant forfeits the reserved capacity. Under very limited extenuating circumstances, consideration may be given for an extension of the 24-month period.

A. Proposed Compliance Requirements

To ensure only participating customers eligible for AB 2109 exemptions continue to benefit from the legislation, a reasonable compliance and verification process should be implemented. Excluding ineligible customers will certainly reduce cost shifts and ultimately avoid additional pressure on affordability. Furthermore, implementing a compliance program to ensure continued eligibility is in concert with Governor Newsom's Executive Order N-5-24.

The Joint IOUs recommend that the Commission adopt streamlined compliance and validation requirements that balance program integrity with administrative efficiency. At a minimum, participating customers should be required to submit a self-attestation, supported by an affidavit executed under penalty of perjury, demonstrating continued compliance with the statutory technology eligibility requirements set forth in Section 451.7. The IOUs should also have the right to perform a validation site visit as needed. This approach provides a reasonable mechanism for ensuring ongoing compliance while avoiding unnecessary administrative burdens on both customers and utilities. The Joint IOUs believe that existing metering requirements for

determining departed load obligations should be employed in the implementation of this statute; except that only the net generator output metering (NGOM) option for determining exempted quantities will be the sole option for determining exempted NBCs under this statute. The Joint IOUs believe that adopting the NGOM as the sole option for determining the billing amount for the purposes of AB 2109 exemption is the correct and least expensive administrative approach for the following reasons:

1. The NGOM option provides an empirical billing determinant based on actual meter registration that can be employed to provide an accurately exempted amount;
2. The NGOM option provides a billing amount that does not have any adjustments based on forced or planned maintenance outages;
3. The NGOM installation does not place a significant burden on customers as the cost of a NGOM accounts for less than one percent of the total installed cost of a combined cycle generating plant contemplated in these sorts of applications; and finally,
4. The NGOM requires minimal administrative or technical follow up and review after initial installation. Even if there is a change of party under this proposed NGOM-only option, there is no ambiguity in determining exempted billing determinants as the meter registration would be the de facto source for determining exempted quantities under this statute.

Using a NGOM for purposes of measuring this cost shift is appropriate and commonplace for other larger commercial and industrial customers, and will not impose any additional burden to this subset of generating customers.

To implement the exemption, the Commission could direct each IOU to file an implementation Advice Letter describing the specific methodology used to determine eligible load reductions and corresponding nonbypassable charge exemptions if it deems that requiring the NGOM option as the sole option is too restrictive. Consistent with approaches used in other

customer programs, including Economic Development Rate offerings, eligibility and exempted load could be determined using a reasonable historical baseline methodology rather than requiring additional metering infrastructure. The IOUs can leverage existing billing systems and customer-tracking workflows to enroll, monitor, and administer participating customers. The implementation Advice Letters would further describe the procedures used to verify customer eligibility, including the utilities' ability to conduct reasonable audits or site visits, requests for supporting documentation, or at the IOU's discretion, a site audit may be warranted. To protect non-participating customers and maintain program integrity, the Joint IOUs recommend that participating customers remain subject to post-enrollment validation and that utilities retain the authority, consistent with applicable Commission rules, to recover previously provided exempted charges if a customer is later found to have been ineligible or noncompliant with the program requirements.

VII.

COST RECOVERY FOR NEW PROGRAM ADMINISTRATION

Depending on the outcome of the Commission's Decision, the Joint IOUs will incur certain administrative costs associated with this statutory requirement. Each IOU will consider how it might pay for these changes depending on the outcome of a final decision and reserves the right to request a memorandum account as needed, potentially requested through an implementation advice filing if not pre-authorized through a decision.

VIII.

CONCLUSION

The Joint IOUs appreciate the Commission's careful consideration of its proposal to implement AB 2109.

Respectfully submitted,

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Appendix A

Detailed List of Nonbypassable Charges

	SCE per/kWh	PG&E per/kWh	SDG&E $/kW or $/kWh
1. Public Purpose Program Charge (PPPC)	$0.02159	$0.02082	Pure Energy | $0.01840/kWh Demand + Energy | Demand = $0.02/kW Energy = $0.01834
2. Nuclear Decommissioning Charge (NDC)	$0.00003	-$0.00002	$0.00000
3. Wildfire Non-Bypassable Charge (WFNBC)	$0.00591	$0.00591	$0.00591/kWh
4. Competition Transition Charge (CTC)	$0.00002	$0.00024	Pure Energy | ($0.00007)/kWh Demand + Energy | Demand = ($0.02)/kW Energy = $0.00000
5. Power Charge Indifference Adjustment (PCIA)	$0.01868	$0.01902	$0.04354
6. Fixed Recovery Charge (FRC)	$0.00507	$0.00763	
Energy Cost Recovery Amount		$0.00002	
Wildfire Fund Charge		$0.00591	
Wildfire Hardening Fixed Recovery Charge Bond Series 1 (FO issued 6/24/21) *		$0.00033	
Wildfire Hardening Fixed Recovery Charge Bond Series 2 (FO issued 8/5/22) *		$0.00054	
Wildfire Hardening Fixed Recovery Charge Bond Series 3 (FO issued 2/16/24) *		$0.00084	
Recovery Bond Charge Series 1 (FO issued 5/11/21) ***		$0.00390	
Recovery Bond Charge Series 2 (FO issued 5/11/21)		$0.00467	
Recovery Bond Credit		$-0.00857	
Total $/ kWh	$0.05131	0.06124	0.06778/kWh to 0.06779/kWh