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March 25, 2026

Via E-Mail

Leuwam Tesfai
Executive Director
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Re: Comments of Southern California Edison to the Transmission Financing and Ownership Concept Paper Pursuant to Assembly Bill 3264

Dear Executive Director Tesfai:

Enclosed, please find the comments of Southern California Edison to the *Working Concepts in Transmission Financing and Ownership Pursuant to Assembly Bill 3264 and Public Utilities Code Section 913.10, dated March 11, 2026.*

Please let me know if you have any questions or concerns.

Sincerely,

s/ Adam R. Smith
Adam R. Smith
Director, SCE Regulatory Relations

Comments of Southern California Edison to:

Working Concepts in Transmission Financing and Ownership Pursuant to Assembly Bill 3264 and Public Utilities Code Section 913.10

March 25, 2026

Introduction and Executive Summary

Southern California Edison (SCE) appreciates the opportunity to provide these comments on the California Public Utilities Commission's (CPUC) "Working Concepts in Transmission Financing and Ownership" (Concept Paper), which was issued in response to California Assembly Bill (AB) 3264 and Public Utilities Code section 913.10.[1] SCE supports and is committed to the Legislature's and the CPUC's efforts to promote energy affordability for customers and agrees that it is appropriate to examine potential lower-cost solutions to achieve that critical objective. SCE is also mindful of and agrees with the Concept Paper's introductory admonition that "transmission is generally expensive to develop and that alternative financing and ownership models may have limitations on effectively and meaningfully reducing costs."[2] The Concept Paper is correct that "cost containment" principles already underlie California's transmission process, "regardless of what entity develops the transmission" infrastructure.[3] SCE also agrees that "[o]ther measures," specifically "improvements to existing processes," are more likely to "yield high cost savings for ratepayers."[4] Finally, California Investor-Owned Utilities (IOUs) have the necessary expertise, resources, scale, and access to financing required to build, expand, own, and operate the grid, to safely serve California customers, and to "reliably meet state decarbonization goals."[5] Any potential affordability-driven solutions the State may ultimately pursue in this space must remain fundamentally grounded in the reality that financially healthy IOUs are critical for the provision of affordable, reliable, and safe electricity to California customers.

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1 SCE is timely submitting these written comments in response to the CPUC's March 11, 2026, request for public input on the Concept Paper. SCE notes that its responses to the specific questions posed by the Concept Paper are not meant to be exhaustive and reserves the right to supplement these responses and/or provide additional input on AB 3264 and Public Utilities Code section 913.10 in the future, as directed by the CPUC or as otherwise may be appropriate.

2 Concept Paper, p. 1.

3 Concept Paper, p. 2.

4 Concept Paper, p. 1.

5 Concept Paper, p. 1.

Transmission Development Competition/Alternatives Must Be Reviewed with Consideration of the Full Costs and Risks

The general theme of "competition reduces costs" appears in several places in the Concept Paper. For example, it asserts "[w]hile only about 5 percent of all transmission projects are subject to a competitive solicitation and development process nationwide, where it is present, as it is in California, competition has been shown to reduce costs by as much as 40%."[6] While as a matter of foundational economic principles it is true that in general competition can drive down costs, there are critical exceptions and policy considerations that need to be considered when discussing competition in the regulated provision of utility services to customers. A full examination of those exceptions and considerations is beyond the scope of the Concept Paper, but as relevant here transmission infrastructure ownership by non-IOU entities (such as private developers and public entities) does not inexorably lead to lower-cost solutions to customers.

In 2011, the Federal Energy Regulatory Commission (FERC) issued Order 1000, which introduced a new competitive framework in the transmission project planning process. While FERC Order 1000 non-incumbent transmission provider *bids* might be lower than IOU bids on certain projects, often that does not mean that competitive transmission provider *final costs* end up lower than the equivalent IOU costs would have been. The first FERC Order 1000 submission for cost recovery, by competitive transmission provider DCR Transmission, L.L.C. (DCRT), is instructive. As noted by the California Independent System Operator (CAISO) in its Motion to Intervene in that docket:

> Under an Approved Project Sponsor Agreement between DCRT and the CAISO, DCRT is subject to a cost cap of $258,961,024 for the Ten West Link project. However, DCRT's proposed Base Transmission Revenue Requirement is based on a project cost of $555,261,497, almost $300 million more than its binding cost cap and more than double its agreed-upon project costs. … The primary purpose of a cost containment mechanism is to allow Project Sponsors voluntarily to agree to protect ratepayers from significant cost increases that can have a profound impact on rates if left unchecked. The Commission should enforce the terms of the Approved Project Sponsor Agreement and its binding cost containment provisions.[7]

Additionally, any chosen transmission solution must require baseline standards for safety, resiliency, and risk reduction (including, critically, wildfire risk reduction), not just the lowest possible cost. Competitive transmission provider project *specifications* (including for wildfire risk reduction mitigation) are often not apples-to-apples to the benefits in the corresponding IOU

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6 Concept Paper, p. 2 (internal citations omitted).

7 July 21, 2023 Motion to Intervene and Comments of the California Independent System Operator Corporation in FERC Docket ER23-2309-000 at pp. 1-3.

bid.[8] When considering the appropriate transmission solution for any particular project, the state should keep in mind broader objectives of efficient long-term system planning, safety and reliability.

I. Transmission Ownership Structures

The Concept Paper groups the ownership model for California transmission infrastructure into three groups: the IOU model, the public model, and the independent transmission utility model (which itself is broken down into the competitive transmission providers with FERC-regulated rates and transmission providers with subscriber-funded rates).

Question 1: Are there publicly available studies that provide insights on overall cost savings for ratepayers attributable to the various ownership models?

Yes, but there are currently very few publicly available studies that document overall, realized (ex-post) customer cost savings from transmission projects and cleanly attribute those savings to ownership model alone.[9] While publicly available studies—especially from California regulators, academic institutions, and policy research organizations—explicitly analyze transmission projects and assert that public or publicly financed ownership can reduce customer costs, primarily by eliminating explicit return on equity (ROE) costs, lowering financing costs, and avoiding tax gross-ups, there are many assumptions yet to be proven out due to the limited number of completed public or publicly financed transmission projects. For example, UCLA Law's Pritzker Environmental Law and Policy Briefs noted the following tradeoffs regarding public financing:

> The two streams of savings for [Publicly Owned Utilities (POUs)], lower cost of public financing and tax advantages, are key selling points for public ownership and financing. But there is more to the story. First, the tradeoff of not paying an ROE to investors, and instead only taking on debt, is that POUs also hold the investment and operational risk. Any budgetary overruns and the costs of damage caused by the POU's infrastructure must be paid—usually by POU customers or by borrowing more money. Second, the reduced tax burden on POU operations means lower costs for electricity customers but also reduced tax income for the state. In

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[8] For example, the Concept Paper recognizes that "[t]he allocation of risk is an important consideration for PPPs, especially considering the major implications of wildfire liability in California." Concept Paper, p. 17. Wildfire risk in California will persist irrespective of transmission ownership structure.

[9] In addition to the studies/papers SCE references throughout these comments, Berkeley Law's Center for Law, Energy, & the Environment published a paper in October 2024 titled "Improving Transmission Financing in California." Because the concepts and examples in that paper are referenced throughout the Concept Paper, SCE does not further cite to it in these comments.

sum, these savings reflect a different model of cost and risk sharing, rather than a simple reduction in cost or risk.[10]

Since the introduction of FERC Order 1000 in 2011, economists have tried to evaluate the post-hoc impact of head-to-head competition in transmission. However, the purported benefits of competition have been elusive.

As discussed in greater detail in response to Question 2, Concentric has issued several reports regarding competitive transmission since 2019 and has found no consistent evidence of benefits from competitive transmission solicitations.[11] Some projects met cost and timeline expectations, while others experienced cost overages or delays. And while many winning bids include cost caps or other cost-containment mechanisms, they typically contain numerous exclusions that limit customer protections.

Other models exist, like the classical merchant model in South Australia and Montana-Alberta tie-line in the US. The Australian projects ran into financial difficulties and were converted into regulated projects after they were completed. Little performance and behavior information is known about the Montana-Alberta line. Thus, according to a 2019 article by MIT economics professor Paul Joskow, the classic merchant model has not proliferated in any meaningful way.[12]

Question 2. Are there public sources that provide evidence of savings related to competitively bid projects versus projects that default to incumbent investor-owned utilities?

One widely cited study is The Brattle Group's *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value* (released April 1, 2019). Based on then-available U.S. Order No. 1000 solicitation outcomes (noting

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[10] Ruthie Lazenby, et al., *Power Struggle: California's Electric Utility Ownership Dilemma*, Pritzker Environmental Law and Policy Briefs June 2025, p. 9, *available at* https://law.ucla.edu/sites/default/files/PDFs/Publications/Emmett%20Institute/PritzkerPaper.pdf?_gl=1*zxnu22*_up*MQ..*_ga*MTM1MTAwNTYyLjE3NzQzOTAzNjU.*_ga_LH03WX2T8B*czE3NzQzOTAzNjQkbzEkZzAkdDE3NzQzOTAzNjQkajYwJGwwJGgw.

[11] *See* Emma Nicholson, et al., Concentric Energy Advisors, *Building New Transmission: Experience to Date Does Not Support Expanding Solicitations* (June 2019), *available at* https://ceadvisors.com/wp-content/uploads/2024/10/CEA_Order1000report_final.pdf [hereinafter 2019 Concentric Report]; Concentric Energy Advisors, *Competitive Transmission: Experience To-Date Shows Order No. 1000 Solicitations Fail to Show Benefits* (Aug. 2022), *available at* https://ceadvisors.com/wp-content/uploads/2024/10/Competitive-Transmission-Experience-To-Date-Shows-Order-No.-1000-Solicitations-Fail-to-Show-Benefits.pdf [hereinafter 2022 Concentric Report]; Concentric Energy Advisors, *An Updated Examination of FERC Order No. 1000 Projects* (Apr. 16, 2024), *available at* https://ceadvisors.com/wp-content/uploads/2024/10/An-Updated-Examination-of-FERC-Order-1000-Projects.pdf [hereinafter 2024 Concentric Report].

[12] Paul L. Joskow, *Competition for Electric Transmission Projects in the U.S.: FERC Order 1000*, MIT SEEPR WP 2019-004 (March 2019), pp. 4-6.

many projects were not yet completed) and international experience, Brattle reported that competitive processes were associated with innovation and *estimated* cost savings (often summarized as roughly 20–30 percent relative to certain benchmark estimates). Brattle observed that only a small share of ISO/RTO transmission investment had been subject to competition and concluded that expanding the scope of competitive solicitations could provide material customer value if such savings were realized.

Concentric Energy Advisors issued a rebuttal report, *Building New Transmission: Experience To-Date Does Not Support Expanding Solicitations* (June 10, 2019).[13] Concentric criticized key aspects of Brattle's approach, including (among other points) that: (i) many competitively selected projects had not reached completion such that *realized* (ex post) costs and customer savings were uncertain; (ii) Brattle's savings estimates relied on comparisons that Concentric characterized as inappropriate (e.g., comparing different types of cost estimates, and not fully accounting for scope changes); and (iii) Brattle's depiction of material cost escalation for traditionally developed incumbent projects was, in Concentric's view, based on a limited and unrepresentative sample.

Concentric also challenged the Brattle Report's conclusion that incumbent transmission owners experience significant cost escalations, noting that publicly available project tracking data in certain ISO/RTO regions indicated incumbent transmission owners' initial cost estimates were generally reasonably aligned with final or updated costs (which Concentric summarized as modest changes around the initial estimate in the regions it reviewed).[14] Concentric also asserted that solicitations can be time- and resource-intensive.[15] Concentric therefore concluded that the customer benefits of competitive processes remained unproven based on the available evidence at that time.[16]

Concentric later published additional analyses on behalf of the DATA Coalition: *Competitive Transmission: Experience To-Date Shows Order No. 1000 Solicitations Fail to Show Benefits* (August 16, 2022)[17] and *An Updated Examination of FERC Order No. 1000 Projects* (April 17, 2024).[18] These reports examined a set of Order No. 1000 solicitation projects that were in service or in advanced development and reported that, in Concentric's assessment, competitive solicitations had not demonstrated consistent customer savings and were associated in some cases with schedule delays and cost growth relative to bid-based expectations; the 2024 update further raised concerns that cost containment mechanisms (e.g., cost caps) can include exclusions and implementation features that may limit customer protections and reaffirmed Concentric's

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13 2019 Concentric Report.
14 2019 Concentric Report, pp. 3-13.
15 2019 Concentric Report, pp. 25-32.
16 2019 Concentric Report, p. 38.
17 2022 Concentric Report.
18 2024 Concentric Report.

overall conclusion that the benefits of competition, as implemented, remain elusive based on the totality of the evidence reviewed.[19]

Additional publicly available sources likewise reflect mixed conclusions. For example, a December 2023 DATA Coalition whitepaper revisits prior claimed savings using updated project-cost information and argues that competitive solicitations have not, to date, demonstrated consistent net cost savings once actual costs, schedule impacts, and the practical limitations of cost-containment provisions are considered.[20] Relatedly, an affidavit by Dr. Carl R. Peterson (Concentric, 2022) submitted in the context of FERC proceedings similarly contended that the available experience does not support broad conclusions that competitive solicitation has produced superior cost outcomes, and stressed the need to compare like-for-like projects and account for development risk, scope change, and schedule performance when evaluating customer impacts.[21]

These publicly available sources reflect that the record is mixed and methodologically contested. While Brattle and other proponents assert that ex ante costs resulting from competitive solicitations may be lower (bid or award commitments relative to planning estimates), Concentric and others recognize that ex post costs (in-service, realized costs) may be significantly impacted by scope changes, permitting outcomes, inflation, and schedule delays. In addition, the design of cost-containment commitments (including exclusions, allowances, and cost allocation of specific change events) varies by solicitation and region, which can materially affect the degree of customer protection and makes broad generalizations about realized savings difficult. Moreover, incumbent utilities and their customers have inherent built-in cost-efficiencies for many potential transmission projects, such as existing rights-of-way. Specifically, statewide transmission siting policies set forth in the Garamendi Principles encourage the use of existing rights-of-way where technically and economically justifiable for efficiency and environmental reasons.[22]

Accordingly, there is not a clear consensus in public literature that competitive transmission processes, as implemented in ISO/RTO regions to date, have consistently produced net cost savings to customers relative to incumbent development.

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19 2024 Concentric Report, pp. 1-2, 41-42.

20 Developers Advocating Transmission Advancements, *Revisiting the Evidence on Cost Savings from Transmission Competition Whitepaper*, Dec. 2023; *see also* Developers Advocating Transmission Advancements, *Recent Experience with Competitive Transmission Projects and Solicitations*, Feb. 2025, *available at* https://www.modernizethegrid.com/wp-content/uploads/2025/02/DATA-Whitepaper-2024_2-5-25_vF_edit.pdf.

21 Affidavit of Dr. Carl R. Peterson submitted in FERC Docket No. RM21-17-000, Sept. 19, 2022.

22 *See* SB 2431 (Garamendi), Chapter 1457, Statutes of 1988.

II. Potential Options for Achieving Transmission Cost Savings

Question 3: Are there publicly available case studies of a government entity financing and building electric infrastructure at lower cost compared to a private entity? Are there publicly available data about the scope of the project and its costs?

For a discussion about traditional public ownership of transmission lines (e.g., by a publicly owned utility) as an alternative ownership model—a structure that has existed in California for more than 100 years—please see SCE's response to Question 1, above.

In addition, there has been an increasing recent focus in California regarding electric utilities accessing federal grant and loan funding for electrical infrastructure projects, including for transmission infrastructure. For example, the Concept Paper briefly discusses federal funding as a possible source of alternative funding for new transmission projects, but notes that while "[f]unding sources currently exist [their] future availability is unclear."[23] While SCE generally welcomes the opportunity for federal support for infrastructure investment, there are significant risks associated with over-reliance on such funding, as illustrated below.

SCE has applied for and been the beneficiary of several grants, including from the 2021 Infrastructure Investment and Jobs Act (IIJA), which was initially seen as a significant opportunity for SCE and the IOUs to secure grant funding to advance a number of potential projects. As noted in a letter from SCE Chief Executive Officer Steven Powell to former CPUC President Reynolds, the IIJA funds offered the opportunity for:

- The expansion or acceleration of safety and reliability upgrades ready for implementation,
- Assessment of novel infrastructure solutions to solve emerging grid challenges, and
- Innovative demonstration projects required to reimagine the grid and fulfill SCE's Pathway 2045 vision for decarbonizing California's economy.[24]

Ultimately, however, SCE was only awarded three IIJA projects for relatively modest amounts of investment, and even these projects can best be characterized as demonstration-type projects, with guidance emphasizing deployment of emerging technology, testing new delivery models, forming new public-private partnerships, and generating learnings that de-risk future investment. As a result, such projects often focus on innovation and market transformation rather than typical traditional capital infrastructure replacement.[25] Overall, SCE cautions that federal awards are

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23 Concept Paper, p. 14.

24 Southern California Edison Company, *SCE response to CPUC January 24 letter regarding Infrastructure Investment and Jobs Act of 2021 – federal funding opportunities* [Letter from Steven D. Powell to Alice Busching Reynolds] (Feb. 18, 2022).

25 SCE is also aware of Pacific Gas and Electric Company's (PG&E) $15 billion IIJA loan guarantee from the Department of Energy (DOE) to finance grid modernization projects (https://www.pge.com/en/newsroom/currents/energy-savings/pg-e-federal-loan-guarantee-

subject to political volatility with some funds ultimately being withdrawn; thus, reliance on public funds for critical transmission infrastructure that can already take approximately seven years (and sometimes significantly more) to complete cannot be over-relied upon if funding during that period may not materialize due to state or federal budgets or political priority changes.

Question 4: Are there publicly available case studies of a government entity financing an infrastructure project with the participation of private equity or other private sector financing, with public data about how the project financing costs were reduced because of the public-private partnership?

In the United States, the private-public partnership (PPP) model for building infrastructure has been utilized relatively infrequently compared to certain other industrialized economies. In 2015, the United States Department of the Treasury concluded that:

> Realizing the potential taxpayer benefits of public-private partnerships (PPPs) in infrastructure investment, including higher quality per dollar and faster project delivery, depends on allocating project risks to the party best able to manage them. Arguably, demand risk is the most important source of uncertainty affecting an infrastructure project's financial viability, particularly in the case of new build, or "greenfield" projects in which the private partner's compensation is determined by user volume, but for which no history of use exists. PPPs have typically used the basic user fee or availability payments models to allocate all demand risk and (therefore revenue risk) to either the private partner or the government, limiting the number of PPP deals that investors and project sponsors may find attractive. However, recent deals have migrated away from the basic user fee arrangement after several prominent PPPs using it encountered financial difficulty. This paper presents three alternative incentive structures for PPP contracts that can potentially benefit both public sector sponsors, by delivering higher quality per dollar, and private investors, by generating attractive returns. The rate of return model, price cap model, and "sharing" model all apply principles from the regulation of privately-owned energy and telecom infrastructure to PPP projects that generate user fees. In addition, these alternative risk- and profit-sharing approaches may create choices that are attractive to investors and sponsors with risk preferences and return expectations not accommodated by more commonly used models. By expanding the options for sponsors and investors to

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approved.html). In addition to the IIJA projects, SCE has also been the recipient of previous, limited federal grant funding for electrical infrastructure, including from the 2009 American Recovery and Reinvestment Act (ARRA). Specifically, pursuant to the ARRA, SCE built the Tehachapi Storage Project (TSP) (Fact Sheet: Tehachapi Wind Energy Storage Project (October 2012)) and the Irvine Smart Grid Demonstration (ISGD) (The Irvine Smart Grid Demonstration Leads the Way to Modernizing California's Electric Grid).

consider in PPP negotiations, these incentive structures have the potential to increase the number of PPP deals and improve the odds of the projects' long-term success.[26]

As the Concept Paper notes, "[p]ublic entities can be investment constrained" or otherwise have "debt limits," which leads to such entities "partner[ing] with private equity ownership … to get access to additional capital … ."[27] In other words, the appetite and capacity for additional public debt are not unlimited. Although not made explicit in the Concept Paper, it is axiomatic that in such arrangements end-use customers are implicitly paying for an embedded proxy for an equity-level rate of return in their resulting rates (recovered through the contractual fees ultimately passed through to end-use customers).[28] The IOUs' ROEs are regulated by the CPUC and FERC and reflect a litigated, approved return to reflect appropriate total asset portfolio risk; no such consumer-protective mechanism applies to private investors financing a stand-alone (presumably riskier) transmission project. As the Concept Paper notes, such structures can also lead to misaligned cost-cutting incentives by the private entity during the "operate" phase to maximize profit and assumes there will be a willing and viable entity to assume "ownership" at the conclusion of the term. In addition, a public entity is chartered to provide a public good and/or service, and any capital-intensive transmission investments it undertakes will crowd out other necessary public policy investments. And the private entity co-partner (to the extent it is unregulated) will have interests and incentives that may not necessarily be aligned with the interests of the public entity.

In California, the most prominent example of a public-private transmission partnership is the Path 15 Transmission Project, which is majority-owned by a private entity (currently Viridon, as discussed in the Concept Paper – 72 percent), and minority-owned by an IOU (PG&E – 18 percent) and a public transmission entity (Western Area Power Administration (WAPA) – 10 percent).

In other Western States, New Mexico, Colorado and Washington provide examples. The New Mexico Renewable Transmission Authority (RETA) was established in 2007 to plan, finance and

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[26] US Department of Treasury, Office of Economic Policy, *Expanding the Market for Infrastructure Public Private Partnerships Alternative Risk and Profit Sharing Approaches to Align Sponsor and Investor Interests* (April 2015), *available at* https://home.treasury.gov/system/files/226/Expanding_the_Market_for_Infrastructure_Public_Private_Partnerships_Alternative_Risk_and_Profit_Sharing_Approaches_to_Align_Sponsor_and_Investor_Interests_APR2015.pdf.

[27] Concept Paper, p. 9.

[28] The same is undoubtedly true for transmission lines built pursuant to the Subscriber Participating Transmission Owner (SPTO) model, where private developers outside of the CAISO Balancing Area finance the project and then recover their costs from end-use customers through long-term power purchase agreements with load-serving entities in California (such as the IOUs, Community Choice Aggregators (CCAs), or municipal utilities). *See also* Concept Paper, p. 17 (regarding the PPP model, "where the state entity is not restricted from taking an equity interest, the developer may still lack incentives to partner since the private entity's equity may be diluted by a state share of ownership").

acquire high voltage transmission infrastructure. At least two projects have been developed through RETA using public funding and co-development models with developers (SunZia and Western Spirit). The Colorado Electric Transmission Authority (CETA) was established in 2021 and can issue revenue bonds, establish transmission corridors, identify transmission needs, and coordinate with other entities to establish intra- or inter-state transmission. However, it essentially only operates as a developer of last resort if no other entity is willing to develop a relevant project. In March 2026, the Washington State Legislature passed a bill establishing the Washington Electric Transmission Authority (WETA), designed in part to develop projects that utilities are not able or willing to build.

Outside of the United States, the PPP model has been most extensively deployed to date by the United Kingdom and Australia. In those countries, certain commentators have observed that while projects have sometimes delivered cost savings compared to traditional infrastructure investment, they have also faced cost overruns, delays, and stranded assets.[29] SCE also understands that both of those countries have significantly slowed and/or scaled back the use of such structures. As discussed more fully in the response to Question 7 below, alternative financing strategies and/or ownership structures will not address existing significant structural issues impeding the cost-effective and timely building of transmission in California. Absent significant and necessary reform, whatever entity builds, owns and operates a new transmission line—irrespective of how it is financed—will continue to be confronted with "challenges with obtaining land rights or right[s]-of-way (ROW), long lead times for procurement of necessary equipment, [and] permitting at all levels of government," all of which lead to significantly "higher costs" for customers.[30]

Question 5: At what scale have certain financing solutions been used? What are the constraints, opportunities, risks, and/or tradeoffs of scaling up other kinds of financing?

The AB 3264 concept paper considers two solutions to lower the cost of capital: (1) lower the cost of debt, and (2) reduce the share of equity.

Option 1 discusses the use of public tax-exempt bonds to reduce the effective cost of debt. SCE has issued over $700 million in tax-exempt bonds benefiting customers. These securities are often limited in scope to certain projects and require an agreement between the issuing government agency and the utility. For a 2 percent reduction in the cost of debt, the average difference between BBB corporates and municipalities from Federal Reserve Economic Data, SCE estimates customer savings of ~$8/year annual savings, noting that the analysis assumes 65

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29 *See, e.g.*, Caroline Miller Smith, et al., *PPP trends: Lessons learned from the UK, Australia and Türkiye*, White & Case (May 28, 2025), https://www.whitecase.com/insight-our-thinking/ppp-trends-lessons-learned-uk-australia-and-turkiye.

30 Concept Paper, p. 6 (internal reference omitted); *see also id.* at p. 12 ("New financing structures may not yield meaningful net benefits, given the price of these projects and other factors that can be more significant in driving project costs.").

years of levelized transmission costs in $5 billion capital investment across SCE, PG&E, and San Diego Gas & Electric Company (SDG&E).

Option 2 discusses lowering the equity layer. While it is true that "the cost of debt is typically cheaper than the cost of equity," it does not logically follow that "a higher proportion of debt would reduce the overall cost of financing."[31] Private companies (such as IOUs) that are too highly leveraged are inherently risky from a financing standpoint (i.e., such a structure will "increase the probability of default").[32] SCE's current credit ratings are at BBB-/Negative (S&P) and Baa1/Stable (Moody's). Lowering the equity layer would increase the financial leverage of the operating company, potentially making the operating company a riskier holding, all else being held equal. This option is not practical because SCE is currently at the precipice of non-Investment Grade, particularly with S&P, since a rating below BBB- would be non-Investment Grade. Falling to non-Investment Grade would potentially raise the cost of capital across all forms of financing and raise customer costs more than the potential benefit of lower costs from the higher debt layer. Furthermore, SCE's short-term credit rating is currently at A3 (S&P)/P2 (Moody's) and any further downgrade by S&P would remove SCE's access to the commercial paper market and increase customer costs through increased short-term borrowing costs. In D.25-12-043, the Commission approved PG&E's Yield Spread Adjustment for their lack of access to the commercial paper market and its impact to interest on balancing and memorandum accounts.

Question 6: How does tax liability for government entities differ from that of investor-owned utilities?

In general, government-owned income-producing properties and activities are exempt from federal income tax. The exemption rests on constitutional intergovernmental tax immunity principles and statutory exclusions. The only consideration that potentially changes this taxable status is if the government entity sets up a corporate entity, in which case the newly formed legal entity may be subject to income taxes, but the government entity would be exempt from taxes on the subsequent dividend. Similarly, California government agencies are typically exempt from property taxes on property they own in the state. SCE is subject to income taxes on all its revenue and property taxes on everything it owns, although the 2017 Tax Cuts and Jobs Act (TCJA) reduced the corporate federal tax rate to 21 percent (from 35 percent). In a partnership scenario or joint venture, the government entity would be exempt from taxes on its share of profits, but any private entity involved in the partnership would be taxable on their share.

The CPUC should also not assume that tax-obligation avoidance associated with transmission projects would be cost-free for California customers.[33] While that may be generally true for

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31 Concept Paper, p. 3.

32 Concept Paper, p. 3.

33 *See* Concept Paper, p. 12 ("Assuming other costs are the same, tax savings could reduce transmission costs, in part shifting the burden from ratepayers to taxpayers.").

avoided federal income taxes, to the extent that future transmission projects do not result in certain taxes paid to California sovereign entities, that would result in a dollar-for-dollar revenue deficiency for those entities (in addition to foregone municipal franchise fees), potentially impeding their ability to fulfill their other spending obligations and commitments to the public without resorting to additional taxation.

Question 7: Are there publicly available examples of electric infrastructure project costs reduced because of any of: permitting exemptions or streamlining, meeting/beating timelines, or incentive/penalty structures for the project lead?

It is well understood that longer permitting processes lead to meaningfully increased project costs. Increased costs include those spent on the permitting process itself, as well as resulting secondary cost increases stemming from inflation, extended financial carrying costs and other issues that arise during the delay. A wealth of publicly available information highlights the additional expenses incurred during lengthy permitting processes.

According to a 2024 report from the United States Department of Energy (DOE), electric grid transmission projects took an average of 10 years to complete, with many projects taking up to 15 years.[34] Most of that time, often as much as 80 percent, was spent on waiting for the project to be permitted.[35] The CPUC's data show an average of 2.4-2.7 years for permitting, and SCE recently reviewed the permitting timelines for its own projects and found similar timeframes, although durations appeared to be getting longer.[36] SCE notes that the Concept Paper's reliance on an average for the amount of time required to complete transmission projects and the number of transmission projects that will require environmental review[37] significantly over-indexes on less complex, less costly, and therefore less meaningful installations.[38]

Permitting-related delays have significant cost implications. For large infrastructure projects, construction costs were susceptible to increases of 24 to 30 percent over project timelines,

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34 U.S. Department of Energy, *Transmission Impact Assessment Power Sector Infrastructure Deployment to Reduce Costs, Improve Reliability, and Lower Pollution* (Oct. 2024), *available at* https://www.energy.gov/sites/default/files/2024-10/DOE_OP_2024_Report-Transmission_Impact_Assessment.pdf.

35 *The High Costs and Dangers of Permitting Delays*, The National Register, Mar. 17, 2026, *available at* https://nationalinterest.org/blog/energy-world/the-high-costs-and-dangers-of-permitting-delays.

36 *Southern California Edison Company's (U 338-E) Comments On Order Instituting Rulemaking To Update And Amend Commission General Order 131-D*, Appendix A, filed June 2, 2023 in R-23-05-018, *available at* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M512/K127/512127378.PDF.

37 *See* Concept Paper, p. 8 ("[O]f the 715 active transmission projects, only 24 of the projects will require a full environmental review and CPUC permit.").

38 In addition, the report the Concept Paper relies on for this statistic only includes projects above $1 million with spending in the last five years, which excludes many older and expensive projects (i.e., those completed more than 5 years ago with no trailing spend).

spurred mainly by material and labor cost inflation and added overhead costs.[39] Similar results have held true for electrical transmission projects. One study showed transmission projects in the Pacific Northwest becoming more expensive by anywhere from 11 to 30 percent—hundreds of millions in real dollars—due to permitting delays, protracted environmental reviews, and in some cases associated litigation.[40] Supply chain issues, material shortages and increasing property values, among many other factors, contribute to project cost increases even if the project is not significantly modified or an alternative is selected during the permitting process.

Even more, permitting delays can cause cost increases to cascade in several ways. Independent generator interconnections can be delayed while waiting for grid access, postponing production of clean energy and affecting those projects' incoming returns, ability to meet required financing or tax credit milestones, or developers' willingness to undertake new projects without significant additional financial incentives. For example, Internal Revenue Code sections 45Y and 48E, as amended in the One Big Beautiful Bill, establish stricter requirements for solar and wind projects seeking to utilize the Clean Electricity Tax Credit, including new deadlines for the start of construction and placement in service. While not specifically transmission-focused, similar delays in permitting utility interconnection facilities such as substations or transmission line improvements that carry energy generated from planned clean energy generation projects onto the grid could render those projects' eligibility for the tax credit at risk.

While it is difficult to quantify exactly how much of any particular project's costs might be avoided if permitting exemptions or streamlined processes were available, it is clear that exemptions and other streamlining efforts, including at CPUC, would substantially reduce overall transmission project costs. SCE recently estimated the cost impacts of permitting delays on five projects in the permitting process. Using 2025 inflation data as a basis for cost escalations, SCE found that project costs could be expected to increase by roughly 6 percent due to a three-year permitting delay, regardless of whether the project proponent were an incumbent utility or some other developer (even without accounting for extreme events such as Covid-related supply chain delays or equipment manufacturer unavailability or increases in project scope that also might emerge from longer permitting processes, such as alternative routing, additional property acquisition or more expensive technologies like undergrounding).[41]

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39 McKinsey & Company, *Unlocking US federal permitting: A sustainable growth imperative*, July 28, 2025, *available at* https://www.mckinsey.com/industries/public-sector/our-insights/unlocking-us-federal-permitting-a-sustainable-growth-imperative.

40 Siteline Institute*, The High Cost of Slow Permitting*, Nov. 20, 2025, *available at* https://www.sightline.org/2025/11/20/the-high-cost-of-slow-permitting/.

41 Two historical SCE projects illustrate the extreme cost implications of protracted permitting delays. First, the Riverside Transmission Reliability Project (RTRP) was at one point estimated to cost approximately $150 million, but after lengthy permitting processes at both the City of Riverside and the CPUC lasting more than 10 years, and subsequent re-consideration by Riverside and a Petition for Modification filed by the City of Norco, the project, now under construction, is currently estimated at $750 million – or about five times its original estimate

Conversely, SCE's preliminary but conservative internal analysis found that for a potential $2 billion transmission project, the savings from significant permit streamlining could be around $180 million. While already noteworthy, when scaled across the broad spectrum of transmission projects identified in CAISO's 20-year plan, eliminating these additional costs could lead to significant additional savings for California's electricity customers.

In other proceedings, the CPUC has raised concerns that while utilities may have a backstop in the form of Construction Work in Progress (CWIP) to offset rising costs, lengthy permitting processes and other delays lead to those increased costs being borne by customers.[42] While it is true that CWIP incentives can help bridge financial gaps so that regulated utilities are able to continue construction work, SCE agrees with the CPUC's concern that lengthy permitting processes ultimately result in rising costs borne by customers. SCE faithfully undertakes new transmission projects to benefit its customers through improvements to capacity, resiliency, and the deployment of renewable energy, and delivering upon those commitments when a project is delayed jeopardizes that objective. Moreover, SCE is committed to doing its part to help the state achieve policy goals related to greenhouse gas targets and carbon reduction goals by 2045. This can only be accomplished through the timely construction of both new generation and new transmission, much of which depends on efficient permitting. Incentives and backstops might help utilities finance individual projects in the short term, but overall reductions in permitting would be far more impactful in reducing project costs.

Question 8: How does exposure to liability and other risk affect public utilities' willingness to own transmission?

SCE is not submitting comments on this question at this time except to note that only the IOUs who have made significant shareholder contributions have access to the Wildfire Fund to protect customers from catastrophic financial losses in the case of an ignition caused by transmission equipment.

(albeit with about half of the transmission line to be underground). Second, SCE first submitted an application to construct the Alberhill Substation Project in 2009, and after years of environmental analysis, independent consultant reviews and evidentiary proceedings, it was not until just last week—March 19, 2026—that the project was approved. Over that time, project costs increased from $241 million to $472 million – almost doubling the early cost estimate (despite modifications SCE made to the project design which are actually expected to result in some *reductions* in overall project cost).

42 *See* CPUC Protest in FERC proceeding EL24-71-000, p .6.

III. Alternative Ownership Models

Question 9: Please comment on feasibility of either of these models (Build Operate Transfer or Lease Type PPP) for California. Please specify barriers and the structural elements that would have to exist for the model to develop transmission at lower costs.

SCE is unsure if this question assumes the private entity in the "Build and Operate" phase is assumed to be an IOU or a different private entity. SCE assumes the question assumes that a public entity would take final ownership over the transmission project at the end of the build-operate term. Based on this assumption, SCE refers back to its comments above.

Finally, in discussing a state entity assuming ownership of new transmission facilities and entering into lease agreements with private operators, the Concept Paper states that "[g]ranting this authority to an existing entity, rather than creating a new entity like [New Mexico's Renewable Energy Transmission Authority (RETA)]" could achieve more cost-effective financing.[43] California's history of re-purposing existing state entities to assume traditional electrical utility functions should be carefully considered before potentially implementing any similar structure.

[43] Concept Paper, p. 17.