UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

The Nevada Hydro Company, Inc.	)	Docket No. EL18-_____

PETITION OF THE NEVADA HYDRO COMPANY, INC.
FOR DECLARATORY RULING

Pursuant to Rule 207 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. § 385.207, The Nevada Hydro Company, Inc. ("Nevada Hydro") hereby requests the Commission to issue a declaratory order that based on the specific facts of this case: (1) the Lake Elsinore Pumped Storage ("LEAPS") facility is a wholesale transmission facility as established in the *Storage Policy Statement*,[1] and (2) LEAPS is entitled to cost-based rate recovery under the California Independent Operator Corporation's ("CAISO") Transmission Access Charge ("TAC") set forth in its Open Access Transmission Tariff ("OATT" or "Tariff").

I. INTRODUCTION AND SUMMARY

LEAPS is a $2 billion advanced pumped storage hydroelectric infrastructure project with a hydroelectric license application currently pending before the Commission. LEAPS will provide the kind of wholesale transmission and transmission support services that the CAISO has found necessary to preserve the reliability of the transmission grid given the challenges presented by California's policy to meet 50% (or more) of the State's energy needs through renewable energy. With Nevada Hydro's hydroelectric license in process, it is coming before the Commission with this Petition to confirm that LEAPS is eligible for the rate treatments outlined

[1] *Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery*, 158 FERC ¶ 61,058 (2017) ("*Storage Policy Statement*").

in the *Storage Policy Statement* to obtain the assurances necessary to continue the development process as it participates in CAISO's 2018-2019 transmission planning cycle.

As explained below, the Commission previously declared that LEAPS is an "Advanced Transmission Technology" under Sections 1223 and 1241 of the Energy Policy Act of 2005 ("EPAct 2005"),[2] but denied its request for cost-based rate recovery under the TAC over concerns that CAISO would be too involved with LEAPS' operations and risked its independence by becoming a market participant.[3] Since then, the Commission allowed such cost recovery in the *Western Grid* case where it found the CAISO independence concerns could be solved through operating procedures,[4] and elaborated upon its case-by-case criteria for treating electric storage as functional wholesale transmission facilities in the *Storage Policy Statement*. The gist of the test—which we will elaborate on below—is that to receive cost-based rates the owner and operator of the storage facility must (1) operate it as a transmission facility to provide grid support services at CAISO's direction, (2) assume responsibilities for operating the facility and setting offer parameters for any incidental market-based services sold into wholesale markets to ensure that CAISO does not become a market participant, and (3) establish revenue crediting or other means to ensure that any market-based sales do not result in double recovery of its cost-of-service revenue requirement.

LEAPS will have the characteristics and operating procedures to qualify it as a wholesale transmission facility as defined in *Western Grid* and the *Storage Policy Statement*. Nevada Hydro will be solely responsible for day-to-day operation of LEAPS as explained herein. Nevada Hydro will fully credit its cost-based transmission rates with any revenues it receives for

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[2] Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594, 953-54 (2005).

[3] *The Nevada Hydro Company, Inc*. 122 FERC ¶ 61,272 (2008).

[4] 130 FERC ¶ 61,056, *reh'g denied*, 133 FERC ¶ 61,029 (2010).

wholesale market services that are incidental to the transmission reliability and support services that it will provide at CAISO's direction. Full crediting of revenues ensures that LEAPS will not cause wholesale market distortions, as the Commission found in the *Storage Policy Statement*. Because LEAPS will operate as a wholesale transmission facility that will *not* seek to earn market revenues *in addition to* its cost-based rate recovery, there are no broader market pricing policy concerns of the sort expressed by Commissioner LaFleur in her dissent to the *Storage Policy Statement*.

The Petitioner respectfully requests the Commission to give prompt consideration to the matters raised herein to provide essential guidance as CAISO begins its 2018-2019 transmission planning cycle, where Nevada Hydro is requesting consideration of LEAPS as a wholesale transmission facility. Despite the Commission having repeatedly rejected CAISO's position in the *Western Grid* case and the *Storage Policy Statement* that electric storage facilities should always be treated as generation,[5] the CAISO has persisted in that view through its most recent 2017-2018 transmission planning process.[6] As a result, the CAISO has never included electric storage facilities in any transmission plan, while almost simultaneously producing a series of reports touting the grid management virtues of pumped storage. CAISO has instead urged the California Public Utilities Commission ("CPUC") to use its State procurement process to acquire the technology because the "fast ramping and flexible" services it can provide are necessary to "balance the grid," "mitigate over-generation conditions" caused by heavy reliance on renewable energy, and contribute "solutions that will allow for the reliable operation of a highly dynamic

[5] *Storage Policy Statement* at P 9; *Western Grid*, 130 FERC ¶ 61,056 at P 43.

[6] California Independent System Operator Corp., *2017-2018 Transmission Planning Process Unified Planning Assumptions and Study Plan*, at 30 (Mar. 17, 2017) ("energy storage . . . could be selected . . . *as an alternative to* the conventional transmission or generation solution") (emphasis added), *available at* http://www.caiso.com/Documents/Final2017-2018StudyPlan.pdf.

grid."[7] In fact, in the CPUC's proceeding to investigate the State's need for electric storage, CAISO explained that:

> CAISO studies demonstrate that additional bulk energy storage with fast-ramping capabilities is essential to balance California's rapid rise toward a 50% renewable grid. Not only would California benefit from additional bulk energy storage resources such as pumped storage, *California could be harmed without them*.[8]

As these are all precisely the sort of reliability and public policy matters that fall squarely within FERC's wholesale transmission and service reliability jurisdiction, they should not be left to the discretion of a state public service commission that is not charged with protecting interstate commerce. In short, this Petition presents the Commission with the opportunity to exercise its interstate wholesale transmission authority and thereby provide essential rate certainty to support a major job-creating infrastructure project that will supply the transmission and grid support services that CAISO itself has found to be necessary to protect the public interest.

Nevada Hydro is attaching as Exhibit 3 the affidavit of Mr. Ziad Alaywan, the President and Chief Executive Officer of transmission consulting firm ZGlobal Inc., to explain the wholesale transmission and grid support services that LEAPS will provide to the CAISO, the operating procedures that Nevada Hydro will follow to safeguard CAISO independence, and the revenue crediting plan to ensure LEAPS will not over-recover its cost of service revenue requirement. Mr. Alaywan provided the testimony that persuaded the Commission to conclude

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[7] Ltr. Of 7/21/2015 from S. Berberich, CAISO President & CEO to California Public Utility Commission at 1 (Attached as Exhibit 1).

[8] *Order Instituting Rulemaking to consider policy and implementation refinements to the Energy Storage Procurement Framework and Design Program (D.13-10-040, D.14-10-045) and related Action Plan of the California Energy Storage Roadmap, Rulemaking 15-03-011*, "Comments of the California Independent System Operation Corp. on Track 2 Issues," at 4 (filed Feb. 5, 2016) (emphasis added) (Attached as Exhibit 2).

that the storage project in the *Western Grid* case was a "wholesale transmission facility" entitled to cost-based rate recovery under the CAISO's TAC.

Mr. Alaywan also demonstrates that the benefits of LEAPS will far exceed its anticipated costs using the CAISO's own five-step cost-benefit analysis that led to its conclusion that new large-scale pumped storage will provide significant grid benefits for southern California. CAISO reached that conclusion based upon a truncated application of its study methodology. Mr. Alaywan first calculated the benefit-to-cost ratio that resulted from the CAISO's incomplete study, and then calculated the benefit-to-cost ratio that would result if the CAISO had complied with its own study method. Mr. Alaywan used the CAISO's computer model and assumptions to complete the CAISO's analysis and thereby quantify the benefits under numerous sensitivities. He shows that LEAPS could conservatively provide over $5 billion of benefits through its life cycle, with a potential benefit-to-cost ratio of 1.76:1. These benefits far exceed the 1:1 benefit-to-cost ratio in CAISO's Tariff for selecting transmission projects into its annual transmission plan, and do not count several difficult to quantify benefits that Mr. Alaywan addresses.

In sum, as discussed in more detail below, based on the facts presented herein, LEAPS will function and operate as a wholesale transmission facility, will credit incidental market revenues to consumers, and cost-effectively provide transmission and grid support services that CAISO has said are essential to protect the public interest. The Commission should grant the Petition. In further support, Nevada Hydro shows as follows:

II. COMMUNICATIONS

All correspondence and communications in this proceeding should be directed to the undersigned counsel for Nevada Hydro and to the following persons who should be included on the official service list compiled by the Secretary of the Commission in this proceeding:

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III. BACKGROUND

LEAPS is a proposed $2 billion pumped hydroelectric storage transmission infrastructure project with a planned power production capacity of 500 MW and a pumping capacity of 600 MW. It will be located in Riverside County California at Lake Elsinore, which will serve as the lower reservoir for the LEAPS facility. It will include two new 500 kV interconnecting transmission lines, two new 500 kV substations, three new 500/230 kV transformers, three new phase shifting transformers, and one new 230 kV transmission line. These facilities will be located approximately midway between Los Angeles and San Diego at Lake Elsinore, California, and will serve the transmission systems of San Diego Gas & Electric Company ("SDG&E") and Southern California Edison Company ("SCE"), thereby helping to relieve two of the largest transmission bottlenecks in California.[9] The total energy storage available will be approximately 6,000 MWh per day, allowing for 12 hours of generation at the full plant generating capacity of 500 MW. Nevada Hydro has filed a hydroelectric license application for LEAPS that is currently pending in Docket No. P-14227-003.

Mr. Alaywan explains that LEAPS will provide a variety of grid support services, including reactive power (*i.e.*, VAR) support, load and generation balancing services (*i.e.*, regulation-up and regulation-down services), moment-to-moment load following service,

[9] LEAPS' two 500 kV lines, however, will not connect directly with each other and, therefore, will not create free-flowing ties between SDG&E and SCE.

spinning reserve service and black start service. LEAPS will be able to switch from providing one service to another almost instantaneously. Mr. Alaywan notes that CAISO has recognized that pumped storage facilities support grid reliability in other ways, including:

- Renewable generation integration (*i.e.*, balancing variability and over-generation)
- Frequency regulation
- Power system stability
- Load following
- Contingency reserves
- Inertial response
- Cycling and ramping protection of thermal generation
- Relieving transmission congestion

These services are all becoming increasingly critical as California continues to transition to its ambitious 50% renewable energy goal while at the same time retiring fossil-fueled and nuclear generating resources historically relied upon to maintain a reliably functioning power grid.

With an expected useful life of 50 years, LEAPS would support grid reliability and resiliency in California for the next half century.[10] The need for the grid support services available from large scale pumped storage like LEAPS has grown significantly in California over the past ten years. California's heavy reliance on non-controllable renewable generation has already stressed the power grid and caused other undesirable consequences, such as mid-day price distortions known as the "duck curve," which require CAISO to impose and pay for

[10] The Commission has proposed to define "resiliency" as "[t]he ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event." *Grid Reliability and Resilience Pricing*, 162 FERC ¶ 61,102, at P 23 (2018). LEAPS would provide several attributes of resiliency because of its ability to absorb excess energy, rapidly produce energy on demand, steady grid frequency disturbances, and provide black start service to assist with the rapid recovery of the grid from an outage event.

wasteful generation curtailments, as Mr. Alaywan explains.[11] California's 50% renewable portfolio standard (which may go even higher) will worsen these stresses. Compounding the problems, continuing retirements of controllable fossil generating resources driven by California's regulatory policies and energy pricing trends have made grid management more difficult. Natural gas supply constraints such as service disruptions of the Aliso Canyon natural gas storage complex in southern California only compound the problems because they lead to the curtailment of flexible natural gas-fired generation.[12] On top of these challenges, large base-load nuclear generating facilities at San Onofre and Diablo Canyon will be permanently removed from service.[13] LEAPS can make a significant contribution to managing these grid challenges.

The Commission has ruled that LEAPS is an Advanced Transmission Technology under EPAct 2005,[14] but also denied incentive rates for the project because of concerns that turning operational control of the facility over to the CAISO (as such incentives require) would cause the CAISO to become a market participant.[15] In its previous consideration whether LEAPS should receive cost-based rate recovery via the CAISO's TAC, the Commission directed CAISO to assess the projects' benefits, including its ability to ensure grid reliability or reduce congestion. Rather than dispute LEAPS' benefits, the CAISO argued that LEAPS should rely on market revenues and objected to taking operational control of the project. The Commission ultimately sided with CAISO's operational control concerns to deny LEAPS' incentives petition.

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[11] Exhibit No. 3 at 44-45.

[12] *Id*. at 22.

[13] DOE's most recent national transmission congestion study raises worries about transmission constraints and reliability in southern California due to generation retirements and heavy reliance on renewable generation. Department of Energy, *National Electric Transmission Congestion Study*, at p. 46 (Sept. 2015), *available at*: https://www.energy.gov/sites/prod/files/2015/09/f26/2015%20National%20Electric%20Transmission%20Congestion%20Study_0.pdf.

[14] *The Nevada Hydro Company, Inc.*, 117 FERC ¶ 61,204, at P 27 (2006).

[15] *The Nevada Hydro Company, Inc*. 122 FERC ¶ 61,272 (2008).

Importantly, the Commission did not base its decision on the physical characteristics of the pumped storage facility or whether it would serve a transmission function.

Times have changed in the ten years since the Commission last considered LEAPS. The *Storage Policy Statement* reconciled the Commission's ruling against LEAPS' incentives request with a subsequent decision in the *Western Grid* case finding that storage project to be a wholesale transmission facility and allowing it to proceed through the TPP and potentially obtain rate incentives and cost recovery through the TAC.[16] The Commission found differences in the way the two applicants' proposed to operate their projects to be significant, with Western Grid retaining day-to-day operational control to provide grid support services while following CAISO's instructions.[17]

The *Storage Policy Statement* provides three options for electric storage facilities to obtain cost recovery on a case-by-case basis: (1) market-based rates for the sale of electric energy, capacity and ancillary services under pre-existing policy, (2) cost-based rate recovery of the full revenue requirement for electric storage facilities, or (3) a hybrid approach whereby the cost-based revenue requirement is reduced by market revenues to assure that there is no double recovery of costs from ratepayers. Applicants must show, on a case-specific basis, that their storage facilities will be "wholesale transmission facilities" like the storage facility in *Western Grid*, that they will follow operating procedures like "participating transmission owners," or "PTOs," under the CAISO's Tariff, so that CAISO will not inadvertently become a market participant, and they must show that there are protections against the storage operator over-recovering its cost-based revenue requirement through participation in wholesale power markets.

[16] *Storage Policy Statement* at P 9.

[17] *Id*. at P 8.

The *Storage Policy Statement* built upon the *Western Grid* case where the Commission applied a case-by-case approach for deciding whether electric storage facilities qualify as "wholesale transmission facilities" for purposes of cost recovery. The Commission found that battery storage does not fit neatly into one of the traditional asset functions of generation, transmission or distribution.[18] The Commission examined the way that Western Grid proposed to operate its storage facilities, the specific use of the facilities, and the proposed cost recovery mechanism.[19]

First, the Commission found that Western Grid would use its storage facility more like transmission than generation. Western Grid explained that it would use stored energy ultimately to serve retail load and to provide voltage support, similar to a transmission line.[20] Western Grid further explained its storage facility would be similar to hydroelectric pumped storage because neither facility is a net producer of electricity.[21] Rather, both kinds of storage facility convert electrical energy to another form of energy that can be stored (chemical energy in the case of batteries and potential energy through stored water in the hydroelectric case), and then convert that stored energy back to electricity when needed. Western Grid analogized its storage device to a capacitor bank, which is a device that the Commission has long considered to be a transmission facility.[22] Western Grid further explained that real power produced when it discharged its batteries would be provided to enhance the reliability of transmission service and not for the purpose of commercial sale.[23]

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[18] 130 FERC ¶ 61,056 at P 43.

[19] *Id*. at P 52.

[20] *Id*. at P 18.

[21] *Id*. at P 20.

[22] *Id*.

[23] *Id*. at P 18.

Second, Western Grid distinguished its proposed operating procedures from those the Commission found troublesome in its earlier *Nevada Hydro* ruling.[24] Western Grid stated that it would define the operational roles and responsibilities between itself and the CAISO through completion of the transmission control agreement ("TCA") set forth in the CAISO Tariff.[25] At a minimum, Western Grid planned to assume day-to-day responsibility for five discrete tasks: (1) ensure safe and reliable operation, (2) operate and maintain protective relaying automatics, (3) perform all planned and forced outage reporting, (4) maintain voltage levels, and (5) comply with WECC and NERC reliability standards.[26] Western Grid explained that it would operate its batteries under the CAISO's direction, similar to the way other wholesale transmission facilities are operated.[27]

Third, Western Grid stated that it would not operate its battery facilities for the main purpose of participating in wholesale power markets.[28] Western Grid promised to flow through any incremental market revenues to customers in its participating transmission owner tariff.[29]

The Commission agreed that the operational characteristics of Western Grid's batteries and its proposed operating procedures made the batteries wholesale transmission facilities for study in the TPP and ultimate cost recovery through the TAC. The Commission found that "Western Grid proposes to operate the Projects under the direction of the CAISO in a similar manner to the way in which high-voltage transmission facilities are operated by PTOs under the

[24] *Id*. at P 22.

[25] *Id*.

[26] *Id*.

[27] *Id*.

[28] *Id*. at PP 18-19.

[29] *Id*. at P 19.

direction of CAISO."[30] It added that "Western Grid will be responsible for all operating functions, including maintenance communication, and system emergencies."[31] "Importantly," FERC added, "Western Grid will operate the Projects, at the CAISO's direction, only as transmission assets. They will be operated in a way that is similar to the operation of other transmission assets (*e.g.*, capacitors that address voltage issues or alternate transmission circuits that address line overloads and trips)."[32] FERC also stated that "just like other transmission assets, and unlike traditional generation assets, Western Grid will not retain revenues outside of the transmission access charge, and it will credit any revenues it may accrue as a result of charging/discharging the Projects through its PTO tariff."[33] These operational characteristics and procedures, together with the pass-through of incidental market revenues, led the Commission to conclude that "the Projects are appropriately considered transmission."[34]

The Commission disagreed with the CAISO's arguments that Western Grid's storage facilities should be classified as generation. The Commission observed that "the Projects are being proposed to function as transmission by addressing reliability concerns on the transmission grid through the provision of voltage support and remaining revenue neutral in the CAISO markets."[35] This contrasted with generation, which is "built almost exclusively to produce electricity and has limited shared characteristics with transmission."[36] As to the question whether Western Grid's battery storage facilities should be limited to "capacitor-like services,"

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[30] *Id*. at P 45.

[31] *Id*.

[32] *Id*.

[33] *Id*.

[34] *Id*. at P 47.

[35] *Id*. at P 52.

[36] *Id*. at P 53.

the Commission ruled that selection of Western Grid's facilities would occur through the TPP where CAISO must decide whether they offered a "superior alternative" and whether they "pass a cost-benefit analysis."[37] Now, almost ten years later, the CAISO has found a specific need for large scale pumped storage of the size, location and characteristics that mirror LEAPS.

These FERC policy clarifications since Nevada Hydro last presented LEAPS to the Commission for a TAC cost recovery ruling have been complemented by an evolution in the way California uses electric resources to serve customer needs, which has been mirrored by CAISO's analyses of how those changes affect grid operations. Studies that it performed in conjunction with its 2016/2017 transmission planning cycle, and additional sensitivities published on January 4, 2018, examined the benefits of a "hypothetical" 500 MW pumped storage hydroelectric project in southern California in the vicinity of the SCE and SDG&E load pockets. The 2016/2017 modeling concluded that "[t]he new pumped storage resources brought significant benefits to the system, including reduced renewable energy curtailment . . . lower CO2 emissions, emission costs and production costs, and the flexibility to provide ancillary services and load-following and to help follow the morning and evening ramping processes."[38] Importantly, the CAISO acknowledged that "[t]he net market revenues of the pumped storage resources provided only a portion of the levelized annual revenue requirements. *Developing pumped storage resources would need other sources of revenue streams, which could be developed through policy decisions*."[39] CAISO repeated these conclusions on January 4, 2018,

[37] *Id*.

[38] Exhibit No. 4 at p. 336.

[39] *Id*. (Emphasis added.)

when it published a further study testing the benefits of large-scale pumped storage through several sensitivities.[40]

The *Storage Policy Statement* issued subsequent to the CAISO's 2016/2017 TPP report was precisely such a "policy decision" that makes now the right time for Nevada Hydro to return to the Commission for additional guidance. That policy decision recognized storage service providers must have the option to seek to recover their revenue requirements through both cost-based and market-based methods, provided that certain safeguards are in place. This is critical. As Mr. Alaywan explains in his accompanying testimony, CAISO's markets are structured to provide revenues for energy and a limited number of ancillary services products that leave no means to compensate pumped storage for all of the other services that they can provide. For example, there is no capacity market in CAISO.

As mentioned above, CAISO uses a "Transmission Economic Assessment Method," or "TEAM" for short, to assess the costs and benefits of transmission projects. Mr. Alaywan explains that he examined CAISO's TEAM-like analysis of a hypothetical 500 MW pumped storage facility under several sensitivities and confirmed the CAISO's conclusions that large-scale pumped storage would provide positive grid benefits, in part using CAISO's assumptions about market revenues.[41] To examine LEAPS in a manner comparable to the way CAISO evaluates traditional transmission facilities, Mr. Alaywan took CAISO's analyses further to include elements of the TEAM approach omitted by CAISO, including valuations of the services LEAPS can provide over the expected life of the facility.[42] Using this more complete TEAM

[40] Exhibit No. 5 at pp. 7-8.

[41] This valuation modeling technique does not mean that Nevada Hydro must be a market participant. Rather, it is a means of developing a value for the services that LEAPS can provide.

[42] Exhibit No. 3 at 83-84.

analysis, Mr. Alaywan concludes that the benefits of LEAPS would significantly exceed the positive benefits already found by CAISO through its truncated TEAM evaluation.[43] Expected market revenues will thus offset LEAPS cost of service revenue requirement, thereby making LEAPS revenue neutral in the markets while also being a more cost competitive alternative to other network transmission upgrades.

Below we explain why LEAPS' operating characteristics and proposed operating procedures, together with crediting of incidental wholesale market revenues, make it a wholesale transmission facility, just like the battery storage facility in *Western Grid*. Moreover, as shown by the conservative cost-benefit assessment used by CAISO through its TEAM analysis, LEAPS will provide significant benefits to the transmission network.

IV. REQUEST FOR DECLARATORY ORDER

A. LEAPS is Entitled to be Treated as a Wholesale Transmission Function Facility for Transmission Planning and Cost Recovery

The Commission should find that LEAPS will be a functional wholesale transmission facility under *Western Grid* and the *Storage Policy Statement* because it will have operating characteristics of electric transmission, Nevada Hydro will establish contract-based operating procedures with CAISO so that LEAPS will be used to provide transmission and transmission support services needed to enhance the reliability of the transmission grid, and Nevada Hydro will not operate LEAPS as a traditional market participant because it will credit to CAISO transmission customers all revenues it receives as a result of LEAPS incidental participation in California's wholesale power markets.

[43] *Id*. at 84.

Nevada Hydro is filing this Petition to remove uncertainty regarding the eligibility of LEAPS to be studied as a transmission facility in the CAISO transmission plan for cost-based rate recovery through its TAC like other wholesale transmission facilities. This uncertainty arises because of the CAISO's long-standing position that pumped storage hydroelectric facilities should always be evaluated as generating resources and load, but never as electric transmission.[44] Clarifying LEAPS's status as a wholesale transmission facility consistent with the *Western Grid* decision and the *Storage Policy Statement* will remove that uncertainty and pave the way for CAISO to select LEAPS as a wholesale transmission facility.

1. LEAPS Will Operate as a Wholesale Transmission Facility

The Commission has ruled that LEAPS meets the statutory definition to be classified as an "advanced transmission asset" under sections 1223 and 1241 of the EPAct 2005.[45] In Section 1223, Congress stated that "the Commission shall encourage as appropriate the deployment of advanced transmission technology."[46] Advanced transmission technology is defined in EPAct 2005 as "a technology that increases the capacity, efficiency, or reliability of an existing or new

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[44] *Electric Storage Participation in Regions With Organized Wholesale Electric Markets*, "Response of the California Independent System Operator Corp. to Data Requests," at 8 (Docket No. AD16-20-000)(filed May 16, 2016) (explaining the "distinct participation model for Pumped Storage Hydro units" whereby they "can operate in the mode of Generating Unit or Participating Load and can submit bid components for both modes"); *Utilization in the Organized Markets of Electric Storage Resources as Transmission Assets Compensated Through Transmission Rates for Grid Support Services Compensated in Other Ways, and for Multiple Services*, "Technical Conference Comments of the California Independent System Operation Corp.," at 1-2 (Docket No. AD16-25-000)(filed Dec. 14, 2016) ("While the CAISO is enthusiastic about the role energy storage projects may play in renewables integration (and the potential roles for the CAISO in facilitating these efforts) *these services are clearly not transmission services*") (emphasis added); *Western Grid*, 130 FERC ¶ 61,056, at P 27 (summarizing CAISO's argument that storage is not treated as transmission under its OATT); *see* California Independent System Operator Corp., *2017-2018 Transmission Planning Process Unified Planning Assumptions and Study Plan*, at 30 (Mar. 17, 2017) ("energy storage . . . could be selected . . . *as an alternative to the conventional transmission or generation solution*") (emphasis added), *available at* http://www.caiso.com/Documents/Final2017-2018StudyPlan.pdf.

[45] *The Nevada Hydro Company, Inc.*, 117 FERC ¶ 61,204, at P 27 (2006).

[46] Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594, 953-54 (2005).

transmission facility."[47] EPAct 2005 includes "energy storage devices" like pumped storage hydro facilities as advanced transmission technology.[48]

Putting these prior findings aside, LEAPS will have several physical characteristics that will cause it to function as a FERC-jurisdictional transmission facility. Just like the battery storage project in *Western Grid*, LEAPS "will transport stored energy to serve retail load, similar to a transmission line, and will provide voltage support that is necessary for operation of the transmission system."[49] In fact, Western Grid argued that its similarity to pumped storage supported its request to be treated as a wholesale transmission facility "because they are not a net producer of electricity."[50] As Mr. Alaywan explains, LEAPS will function to store energy purchased from CAISO's wholesale markets and be used to pump water into its reservoir to be released later to provide energy that will be converted back to electricity as needed.[51] As such, LEAPS will convert electrical energy to potential energy and back again to electricity with no net increase to electric production. In fact, as Mr. Alaywan points out, LEAPS will experience energy losses in the conversion process, just as transmission facilities experience energy line losses along their transmission paths.[52] This is similar to Western Grid's battery storage device which was able to convert electricity into chemical energy for storage and later conversion back into electricity.

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[47] *Id*., 119 Stat. at 953.

[48] *Id*. 119 Stat. at 954.

[49] 130 FERC ¶ 61,056 at P 18.

[50] *Id*. at P 20.

[51] Exhibit No. 3 at 7, 14. Nevada Hydro will pay the CAISO the locational marginal price for electricity required by LEAPS in the energy-storage conversion process. *See Electric Storage Participation in Regions with Organized Wholesale Electric Markets*, "Response of the California Independent System Operator Corp. to Data Requests," at 17 (Docket No. AD16-20-000) (filed May 16, 2016) (explaining CAISO electricity pricing rules for energy storage).

[52] Exhibit No. 3 at 14.

Moreover, LEAPS will, via its energy storage capability, be able to transmit electricity to both SCE and SDG&E despite existing transmission constraints. Mr. Alaywan explains that existing transmission bottlenecks make SCE and SDG&E two of the biggest load pockets in California.[53] At CAISO's direction, Nevada Hydro will be able to release energy from LEAPS for delivery to either load pocket to alleviate the constraint. This is a classic transmission service.[54] As the Commission noted in *Western Grid*, the NERC Glossary of Terms defines transmission as "[a]n interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems." The Commission, therefore, ruled that the "Projects are clearly equipment that is associated with the movement or transfer of electricity over the bulk power system."[55] LEAPS will function in this same way to provide transmission service.

Further, as the Commission agreed in *Western Grid*, it has treated facilities that operate and are physically constructed like LEAPS, such as large electrical capacitors, as FERC jurisdictional transmission facilities.[56] For example, in *Southern Co. Services*, 80 FERC 61,318 (1997), the Commission concluded that "reactive power sources available on the Southern system include transmission equipment such as capacitors, reactors and the natural capacitance of transmission lines." (Emphasis added.) More recently, in *Transmission Relay Loadability Reliability Standard*, Notice of Proposed Rulemaking, 127 FERC ¶ 61,175, P 20 (2009), the

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[53] *Id*. at 14, 26.

[54] *E.g.*, *Promoting Transmission Investment Through Pricing Reform*, Policy Statement, 141 FERC ¶ 61,129 (2012) (providing guidance on incentives for transmission investment to relieve congestion).

[55] 133 FERC ¶ 61,029 at P 14 & n.41.

[56] 130 FERC ¶ 61,056 at P 47 ("the Projects as Western Grid proposes to operate them do share some important characteristics with capacitors").

Commission described "specific criteria to be used for certain *transmission system configurations*," stating that such criteria "account for the presence of devices such as series capacitors and address circuit and transformer thermal capability." (Emphasis added.) Mr. Alaywan explains in more detail the ways that LEAPS will operate similar to capacitors.[57]

Finally, as Mr. Alaywan explains, LEAPS is designed to: (1) be used by the CAISO to resolve transmission and system reliability issues when the system is under over-generation conditions, (2) maintain reliability when other transmission facilities are out of service for maintenance, and (3) provide grid resiliencies as the grid is relying more and more in intermittent resources.[58] In such situations, LEAPS would automatically come on-line and would prevent NERC reliability violations, or any interruption of electricity service to customers, and LEAPS would be able to provide reliability services throughout the requisite peak hours and during over-generation hours. LEAPS will perform transmission and reliability functions by providing the voltage control support or load reduction needed for the operation of the transmission system when called to do so. In all, LEAPS will provide ten transmission reliability support services: (1) voltage support, (2) thermal overload protection, (3) frequency regulation, (4) load following, (5) balancing renewable generation, (6) ramping/regulation services, (7) black start service, (8) mitigation of transmission outages/contingency reserves, (9) inertial response, (10) relief of transmission congestion between major load pockets, and cycling/ramping protection of thermal generation. Through these services, LEAPS can be used to mitigate over-generation conditions, overloads, line trips, lines taken off line for maintenance, and voltage dips of affected

[57] Exhibit No. 3 at 17.

[58] *Id*. at 49-78.

transmission line segments on the CAISO transmission system.[59] These are all transmission, or transmission-related, services.

In providing transmission and transmission support services, LEAPS will differ from generators that obtain cost-based revenues as "reliability must run" units. Those units operate to provide capacity to the transmission grid primarily in circumstances when capacity shortage conditions exist. LEAPS, in contrast, will operate during all types of transmission system conditions to support grid reliability. That includes during periods of *excess capacity* provided by renewable resources when CAISO is currently forced to issue directives to curtail output and pay those generators for doing so. In those situations, LEAPS will operate in its pumping mode to pull electricity from the network for storage and conversion back to electricity during the evening ramp hours when electricity becomes scarce. Importantly, in these circumstances LEAPS will be able to quickly switch from absorbing excess electricity in its pumping mode to producing electricity from stored energy. In short, the "product" that LEAPS will provide "is a transmission reliability service that will only be used when there is no competitive product available to address a potential transmission reliability issue."[60]

For all of these reasons, LEAPS will have the characteristics of a transmission facility, rather than a traditional generating asset, just like the electric storage facility in *Western Grid*.

2. Nevada Hydro Will Implement Contract-Based Procedures to Operate LEAPS as a Traditional Transmission Facility.

Nevada Hydro will operate LEAPS consistent with *Western Grid* and the Commission's guidance in the *Storage Policy Statement* to ensure that it does not adversely affect the CAISO's independence and non-discriminatory services. Nevada Hydro will operate LEAPS to provide

[59] *Id*.

[60] 133 FERC ¶ 61,029 at P 17.

transmission and reliability services such as voltage support, relief from thermal overload conditions, and grid resiliency support at CAISO's direction, just like Western Grid.

In the *Storage Policy Statement* the Commission cited to its experience with Western Grid as an example of an acceptable arrangement that would avoid drawing CAISO into a market participant role, and thereby compromise its independence. Western Grid committed to use its battery storage to provide grid support services, and promised that it would retain responsibility for energizing the battery, operating and maintaining it, and would retain responsibility for communications with the CAISO and responding to emergency conditions. Nevada Hydro plans to operate LEAPS the same way, as Mr. Alaywan explains.[61]

Nevada Hydro will become a PTO and operate LEAPS as a transmission facility under the direction of the CAISO through the transmission control agreement in CAISO's Tariff. Nevada Hydro, therefore, will operate LEAPS in the same way that other PTOs operate their transmission facilities. The roles and responsibilities among Nevada Hydro as a PTO, CAISO, and the other PTOs will be defined in the TCA. Nevada Hydro will work with these parties to develop detailed operating procedures at the appropriate time. These detailed operating procedures will address dispatch protocols, other transmission provider responsibilities, such as operating procedures that describe the role and responsibility under normal and emergency conditions, and also describe daily operating responsibilities that Nevada Hydro must perform.

At a minimum, as in the case of *Western Grid*, Nevada Hydro will perform the following tasks: (1) monitor status of the LEAPS project; (2) report to CAISO; (3) coordinate with the CAISO and other PTOs; (4) approve LEAPS maintenance schedules; (5) ensure protective relaying and automatic transfers are maintained; and (6) monitor flows and voltage levels.

[61] Exhibit No. 3 at 18-20.

Nevada Hydro's obligations would include: (1) ensuring the safe and reliable operations of LEAPS; (2) performing the operation and the maintenance of the protective relaying automatics; (3) performing all planned and forced outage reporting; (4) maintaining voltage level; and (5) complying with WECC and NERC reliability standards.

Moreover, as Mr. Alaywan explains, Nevada Hydro, as a PTO, will perform the following operational activities: (1) operate LEAPS in accordance with Good Utility Practice and in a manner that ensures safe and reliable operation; (2) maintain appropriate voltage schedules; (3) provide voltage support when requested by CAISO; (4) operate LEAPS as required by the CAISO to alleviate thermal overload and voltage decay; (5) ensure that LEAPS can automatically connect to the grid upon pre-defined NERC N-1 and N-2 reliability contingencies; (6) respond if the CAISO notifies Nevada Hydro of changes to the status of LEAPS or limitations to automatic voltage regulators or power system stabilizers; (7) maintain or change either the LEAPS voltage schedule or its reactive power schedule as appropriate; (8) notify the CAISO of system conditions and coordinate switching of voltage support or phase shifter equipment; (9) notify the CAISO of events and changes that impact voltage support equipment availability or reliability; (10) de-energize the LEAPS facility; and (11) energize LEAPS.[62]

Nevada Hydro's contract-based operating procedures will, therefore, ensure that it uses LEAPS to provide transmission service and associated services to support the reliability of the transmission grid at CAISO's direction. Nevada Hydro will have full day-to-day operational responsibility. This also means that Nevada Hydro will not operate LEAPS with the intention of

[62] *Id*.

earning revenues through participation in CAISO's wholesale power markets. This is consistent with the Commission's classification of storage as transmission in *Western Grid*.

3. Nevada Hydro Will Not Offer LEAPS Into CAISO's Wholesale Power Markets as a Market Participant.

Nevada Hydro will file its revenue requirement methodology with the Commission for review pursuant to Section 205 of the Federal Power Act at the appropriate time. That filing will include a transmission rate formula, revenue crediting and protocols typical of the many transmission projects that have made such filings. The implementing details of that filing will ensure that LEAPS remains revenue neutral with respect to any incidental sales of electric products or services into CAISO's markets and, therefore, Nevada Hydro will not be a market participant.[63]

Nevada Hydro will not operate LEAPS as a market participant and will remain revenue neutral with respect to any incidental wholesale power sales, as Mr. Alaywan explains.[64] This is consistent with *Western Grid*, where the Commission found the battery storage owner's revenue crediting to be an important factor in treating the facility as transmission: "just like other transmission assets, and unlike traditional generation assets, Western Grid will not retain revenues outside of the transmission access charge, and it will credit any revenues it may accrue as a result of charging/discharging the Projects through its PTO tariff."[65] Nevada Hydro may receive revenues from CAISO for services that are incidental to its operation of LEAPS to support transmission reliability. This is comparable to the way the PG&E operates its Helms

[63] For example, a transmission-owning balancing authority does not become a "market participant" by trading imbalance energy as necessary to operate its transmission system when it flows the costs or credits through to its transmission customers on a dollar-for-dollar basis.

[64] Exhibit No. 3 at 20-21.

[65] *Id*.

Pumped Storage project, which is included in its cost-based rates as Mr. Alaywan explains.[66] Nevada Hydro will fully credit those revenues to LEAPS' cost of service.

Importantly, CAISO will play no role in decisions whether to offer LEAPS into the market, the parameters for such offers or the scheduling of market services from LEAPS. Nor will CAISO have any role in directing LEAPS to pump water for storage or other plant operations. Nevada Hydro will be solely responsible for these decisions, as Mr. Alaywan also explains. This implements the Commission's guidance in the *Storage Policy Statement*.[67]

Finally, Mr. Alaywan explains that LEAPS will not adversely impact CAISO's wholesale markets or unfairly distort prices. The Commission recognized in the *Storage Policy Statement* that collecting cost-based rates in conjunction with market-based services is nothing new because generators in some regions have cost-based rate schedules for the sale of reactive power alongside their market-based sales tariffs.[68] As mentioned, within the CAISO, itself PG&E recovers the revenue requirement for the Helms Pumped Storage facility through cost-based retail rates while offering services into wholesale power markets with the revenues credited to retail customers. This revenue crediting approach implements the Commission's method for protecting against cross-subsidies while also avoiding market distortions, as the Commission has ruled.[69]

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[66] *Id*.

[67] *Storage Policy Statement* at P 27 ("while the RTO/ISO always performs the actual optimization of resources participating in the organized wholesale electric markets, during periods when the electric storage resource is not needed for the separate service compensated at cost-based rates, the RTO/ISO would rely on offer parameters provided by the electric storage resource owner or operator for such operation, just as the RTO/ISO does with other market participants").

[68] *Id.* at P 22.

[69] *Id*. at P 23 ("we believe any concerns that electric storage resources would offer in a manner that suppresses market clearing prices simply because they receive cost recovery (in whole or in part) through cost-based rates could be addressed by the manner in which double recovery is addressed and the costs that go into cost-based rates are established").

4. Cost-Based Rates Ensures That LEAPS Will Realize the Value of All Its Services

Even as CAISO has found that "new pumped storage resources brought significant benefits to the system,"[70] it has candidly agreed that "[d]eveloping pumped storage resources would need other [non-market] sources of revenue streams, which could be developed through policy decisions."[71] The problem is that the lack of policy support has been an impediment to the development of new pumped storage hydroelectric generation for three decades since Pacific Gas and Electric Company placed its Helms pumped hydroelectric storage facility into service in 1984 with its revenue requirement covered by cost-of-service rates.[72]

The Department of Energy succinctly explained the cost recovery impediments to pumped storage (which it referred to as PSH) in its comprehensive Hydropower Vision report published in July 2016:

> While PSH plants provide numerous services and contributions to the power system (a total of 20 PSH services and contributions were identified by Koritarov et al.), in existing U.S. electricity markets they typically can receive revenues only from energy, certain ancillary services (typically for regulation, spinning, and non-spinning reserves), and capacity markets. The provision of black start capability is typically arranged through a long-term contract. <u>Most existing markets have no established mechanisms to provide revenues for other services and contributions of PSH to the power grid</u>. <u>In contrast to competitive electricity markets, the traditional regulated utilities do not have established revenue streams for specific PSH services</u>. The system operator typically optimizes the operation of PSH plants to minimize generation costs for the system as a whole. Therefore, <u>in both traditional and restructured market environments, many PSH services and contributions are not explicitly monetized</u>. <u>Since PSH plants typically provide multiple services at the same time, it is difficult to distinguish the specific value</u>

[70] Exhibit No. 4 at p. 336.

[71] *Id*.

[72] "The Commission has authorized a total of 24 pumped storage projects that are constructed and in operation, with a total installed capacity of approximately 16,500 megawatts. *Most of these projects were authorized more than 30 years ago*." Federal Energy Regulatory Commission, Pumped Storage Projects (webpage), *available at*: https://www.ferc.gov/industries/hydropower/gen-info/licensing/pump-storage.asp (emphasis added).

of particular services and contributions, such as the inertial response, voltage support, transmission deferral, improved system reliability, and energy security. [73]

The Commission's guidance in the *Storage Policy Statement* was animated by similar concerns. As the Commission put it, "electric storage resources may fit into one or more of the traditional asset functions of generation, transmission, and distribution. Enabling electric storage resources to provide multiple services (including both cost-based and market-based services) ensures that the full capabilities of these resources can be realized, thereby maximizing their efficiency and value for the system and to consumers."[74]

Reliance on wholesale markets to support pumped storage in the CAISO may be doomed to failure. As Mr. Alaywan explains, CAISO lacks markets to value many of the services that pumped storage can offer. Its markets are limited to energy and ancillary services, with capacity, voltage support and black start services all procured through bilateral contracts approved by the CPUC. Mr. Alaywan points out that in 2016 the CAISO performed an analysis that found net revenues for a combined cycle gas-fired generating plant ranged between $11/kW-year in northern California and $22/kW-year in southern California—a fraction of the 166 $/kW-year that the California Energy Commission estimated the plant would need.[75] Clearly, pumped storage—which can provide many more services than a combined cycle gas plant—cannot hope to be economic with Califonria's limited wholesale power market opportunities.[76]

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[73] *Hydropower Vision: A New Chapter for America's 1st Renewable Energy Resource*, section 2.7.7 (July 26, 2016) (emphasis added), *available at*: https://energy.gov/eere/water/articles/hydropower-vision-new-chapter-america-s-1st-renewable-electricity-source.

[74] *Storage Policy Statement* at P 2.

[75] California Independent Transmission System Operator Corp., *2016 Annual Report on Market Issues and Performance*, at p. 52 (May 2017); *available at*: http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf.

[76] Nevada Hydro appreciates the Commission's consistent efforts to incentivize electric storage, including the recent rulemaking in Order 841. *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 841, 162 FERC ¶ 61,127 (2018). Expanding market opportunities is unlikely to bridge the wide gap between available net market revenues and the revenue requirement

Following the *Storage Policy Statement* to solve the commercial problem should not be controversial. CAISO's studies have identified numerous grid benefits that new pumped storage resources would provide, and has counseled the CPUC on the wisdom of procuring such facilities. In July 2015, CAISO's President and CEO penned a letter to the CPUC summarizing his concerns with "over-generation and ramping" burdens caused by California's heavy and growing reliance on non-dispatchable renewable generation. He warned that renewable energy procurement trends "will only expedite the need for fast-ramping and flexible resources to balance the grid . . . ." The CAISO emphasized that "[p]umped energy storage, in particular, can be constructed at large scale, with characteristics that are necessary to meet our grid's over-generation and ramping needs."[77] Thus, the CAISO has been a consistent advocate for adding large-scale pumped storage to its grid management arsenal.

B. Mr. Alaywan Demonstrates That LEAPS Passes CAISO's TEAM Cost-Benefits Analysis by a Wide Margin

The Commission recognized in *Western Grid* that section 24 of CAISO's Tariff requires it to choose the superior project when presented with alternatives based on a cost-benefit analysis.[78] Section 24.4.6.7 provides that CAISO will conduct studies to identify transmission needed to address congestion, local area resource requirements, congestion projected to increase over time, or integration of new generation resources or load on an aggregate or regional basis.[79] In determining whether any additional transmission is needed, CAISO will consider the degree to

for a $2 billion project like LEAPS, nor can uncertain market revenues provide the long-term financial certainty that is essential to make such a project financeable.

[77] Exhibit No. 1.

[78] 130 FERC ¶ 61,056 at P 53.

[79] CAISO Fifth Replacement FERC Electric Tariff at § 24.4.6.7.

which the benefits outweigh the costs.[80] CAISO's Tariff establishes no minimum benefit threshold above 1:1.[81]

As Mr. Alaywan explains, CAISO uses the TEAM analysis to assess the costs and benefits of transmission projects for selection in its TPP.[82] He explains that TEAM examines five categories of benefits: (1) production cost savings, (2) capacity benefits through increased import capability into the CAISO balancing authority area, increased deliverability within CAISO, or relief of a known transmission constrained area within CAISO, (3) public policy benefits, such as the ability to lower the cost to integrate renewable energy resources, (4) the ability to relieve the over-supply and associated curtailment problems that arise from excess renewable energy production, and (5) reliability benefits and the ability to avoid other costly transmission upgrades.[83] The analysis uses a full network computer simulation model, market prices for energy and ancillary services, an uncertainty analysis to account for the variability of input assumptions such as natural gas prices, and examines alternatives, such as adding generating facilities, to assess whether there are more economic means to achieve objectives.[84]

The CAISO has in the past two years used portions of the TEAM method to analyze the potential for hydroelectric pumped storage facilities to serve as an alternative to transmission projects selected in the TPP, but not as a transmission solution to be selected as such in the transmission plan.[85] The CAISO performed such an analysis in conjunction with its 2016-2017

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[80] *California Independent Sys. Op. Corp.*, 143 FERC ¶ 61,057, at P 62 & n.116 (2013).

[81] *Id*. at P 300.

[82] Exhibit No. 3 at 26; *see* California Independent System Operator Corp., *Transmission Economic Assessment Methodology (TEAM)*, at pp. 3-4 (Nov. 2, 2017), *available at*: http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf.

[83] Exhibit No. 3 at 26-27.

[84] *Id*.

[85] CAISO's "unified planning assumptions" for the 2017-2018 planning cycle currently underway continues to treat electric storage as an alternative to transmission solutions. California Independent System Operation Corp., *2017-*

transmission plan.[86] The CAISO continued with sensitivity studies that it published on January 4, 2018.[87]

The CAISO's supplemental analysis used several economic sensitivities to confirm its original findings that adding 500 MW of hydroelectric pumped storage to the southern California transmission network "brought significant benefits to the system, including reducing renewable curtailment and renewable overbuild needed to meet the 50% [renewable portfolio standard] target; making use of the recovered renewable energy from curtailment as well as low cost out-of-state energy during hours without renewable curtailment; providing lower cost energy during the net peak hours in the early evening and flexibility to provide ancillary services and load-following and to help follow the load in the morning and evening ramping process; and lowering system production cost to serve load."[88]

The CAISO performed these studies using two variations on California's renewable energy vision: one where its renewable portfolio targets are met with greater amounts of solar than wind energy (the heavy solar case) and the other where wind energy development proceeds at a faster pace than solar energy (the heavy wind case). These two visions have important cost consequences because the heavy solar case leads to excessive energy production in the mid-day hours (the normal daily peak demand), which CAISO must curtail to keep the system in balance. The CAISO must pay the generators to curtail their output, which leads to a relatively more costly grid management future if solar power development predominates. Wind energy tends to

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2018 Transmission Planning Process Unified Planning Assumptions and Study Plan—Final, at p. 30 (Mar. 31, 2017), *available at* http://www.caiso.com/Documents/Final2017-2018StudyPlan.pdf.

[86] Exhibit No. 4.

[87] California Independent System Operator Corp., ISO 2016-2017 Transmission Planning Process—Supplemental Sensitivity Analysis: Benefits Analysis of Large Energy Storage (Jan. 4, 2018), available at: http://www.caiso.com/Documents/SupplementalSensitivityAnalysis-BenefitsAnalysisofLargeEnergyStorage.pdf.

[88] *Id*. at p. 7.

be more prevalent in the morning and evening hours (for example, warming daylight hours cause air over land to rise, leading to sea breezes that drive the wind turbines), thereby providing a more balanced supply profile. This vision leads to more conservative cost assumptions on the expectation that CAISO will curtail relatively less energy supply in the mid-day hours, thereby saving the cost of curtailment payments. Significantly, the CAISO found large-scale pumped storage hydroelectric generation to provide substantial benefits to the southern California power grid under both cases.[89]

Developments affecting the power grid after the initial pumped storage study only reinforced the CAISO's conclusions about the value of pumped storage. Those included the announced retirement of the Diablo Canyon nuclear power station, assuming 50% of combined heat and power ("CHP") gas-fired generation would be dispatchable,[90] and a lower load forecast with greater demand response that would allow California to meet its renewable portfolio standard goals with less new renewable generation. The CAISO found a new 500 MW pumped storage facility to be needed, despite conservatively reducing renewable generating facilities curtailments in the study model, which led to cost savings from less curtailment payments and lower production cost savings compared to its original study. CAISO acknowledged that its identified benefits were highly dependent on the assumptions used in the study model, such as the success of demand response initiatives and the ability to control the operation of CHP resources.[91] For example, "[w]hen all CHP resources are assumed to be non-dispatchable, the

[89] Exhibit No. 4 at p. 336; Exhibit No. 5 at pp. 7-8.

[90] Combined heat and power generating facilities are owned by large commercial and industrial customers for use in their manufacturing processes. Therefore, those generating facilities are operated to meet the manufacturing needs of the commercial or industrial owner, and not the electric needs of the CAISO power grid.

[91] CAISO did not account for natural gas supply-related curtailments of gas-fired general due to the extended and indefinite unavailability of Southern California Gas Company's Aliso Canyon natural gas storage complex.

renewable curtailment as well as the needed renewable overbuild to meet the 50% RPS target increased significantly, as do the production costs."[92] Given that the CAISO does not control the dispatch of CHP resources, the CAISO's qualification was prudent.

Consistent with the observations in DOE's *Hydropower Vision* paper, and the *Storage Policy Statement*, the CAISO acknowledged that market revenues alone are unlikely to support pumped storage:

> The net market revenues of the pumped storage resources provided only a portion of the levelized annual revenue requirements. Developing pumped storage resources would need other sources of revenue streams, which could be developed through policy decisions.[93]

The *Storage Policy Statement* and the ruling requested herein is precisely the sort of "policy decision" highlighted by the CAISO.

Although the CAISO's recent studies of large-scale pumped hydroelectric storage provide compelling support, the studies did not add up the benefits of pumped storage that CAISO identified. They also understated the full benefits by omitting key elements of the TEAM analysis, as Mr. Alaywan explains. In particular, the CAISO's studies had five critical limitations because they:

- were conducted for only one study year (2026),
- did not consider the project's benefit for avoided cost of other projects,
- did not quantify the "reliability" benefits category of the TEAM,
- were not based on a life cycle cost -benefits framework per section 2.4.1 of TEAM, and
- did not incorporate uncertainty or sensitivity analysis suggested in section 5 of TEAM.

Using the CAISO's modeling software, Mr. Alaywan performed three analyses to complete CAISO's work. First, he used the CAISO's analyses as a starting point and then

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[92] Exhibit No. 4 at p. 8.

[93] *Id*. at p. 7.

calculated the dollar benefits of pumped storage under the heavy solar and heavy wind development cases, leaving CAISO's assumptions otherwise unchanged. The following table, reproduced from his testimony, summarizes Mr. Alaywan's calculations:

Table 1. Summary of Benefits from ISO's Large Energy Storage Sensitivity Analysis

Summary of Benefits from CAISO's Large Energy Storage Sensitivity Analysis for a 500 MW Pump Storage in Southern California Load Pocket	**Solar Case ($ millions)**	**Wind Case ($ millions)**
Sensitivity #1 - Summary of the CAISO analysis of the Updated Default Scenario (2026 Base case)	$187.8	$167.0
Base case - Sensitivity #2 - Summary of CAISO analysis, Updated Default Scenario with Non-Dispatchable CHP (2026 Base case)	$217.0	$187.0
Sensitivity #3 - Summary of CAISO analysis, Updated Default Scenario with 2015 IEPR Mid-AEE Sensitivity (2026 Base case)	$188.0	$168.0
Sensitivity #4 - Summary of CAISO analysis, Updated Default Scenario with 4-tier Curtailments Prices (2026 Base case)	$183.0	$175.0

As Mr. Alaywan explains, CAISO's analysis for just one year of benefits (2026) showed that a 500 MW pumped storage facility in southern California would produce benefits to ratepayers between $167 million and $217 million. These benefits derived from just four of the five categories in the TEAM analysis, and did not consider the important "reliability benefits and avoided cost of other projects" category. When Mr. Alaywan compared the dollar benefits of 500 MW of pumped storage to his projected annual revenue requirement for LEAPS of $177

million, he calculated a one-year benefit-to-cost range of 1.03:1 to 1.23:1 and 0.94:1 to 1.06:1 for the heavy solar and heavy wind sensitivities, respectively.

Mr. Alaywan provides a more granular benefits calculation for "Sensitivity #2," which reflects the more realistic scenario where CAISO is unable to dispatch CHP resources. He summarizes those calculations in the following table:

Table 2. Quantified TEAM Benefits for ISO Sensitivity #2 – Updated Default Scenario with Non-Dispatchable CHP

Sensitivity #2 - Summary of the CAISO, Updated Default Scenario Non-Dispatchable CHP (2026 Base case)			
Benefit Categories per TEAM	**Net Cost Reduction / Benefits ($M)**	**Solar Case**	**Wind Case**
California Production Cost Benefits	Net reduction in Energy Cost	$31.0	$37.0
	Net Reduction in Load Following, Regulation and Spin Costs, and Energy Market Revenues for LEAPS	$55.7	$57.4
Capacity Benefits	LCR benefits	$38.0	$38.0
Public Policy Benefits	Reduction in RPS costs	$73.0	$44.0
	Reduction in Emission Costs	-$1.0	-$1.0
Renewable Integration Benefits	Overgeneration cost reduction	$20.4	$11.6
Reliability and Avoided Cost Benefit of other Projects	Interconnection Costs	not studied	not studied
	Avoided large transmission investments	not studied	not studied
	Reliability benefits / Grid Resiliency	not studied	not studied
Total Benefits		**$217.0**	**$187.0**
Annual Revenue Requirements		**$177.1**	**$177.1**
One Year Benefit to Cost Ratio		**1.23:1**	**1.06:1**

Mr. Alaywan built on CAISO's "Sensitivity #2" through an analysis of all five TEAM categories to develop three analyses of the net present value benefits of LEAPS, one for 2026 (as CAISO performed), one for 2030 and a third that calculated the 50-year life cycle benefits of LEAPS. Completing CAISO's analysis to include the fifth category of benefits (reliability and avoided transmission upgrade savings) shows that LEAPS consistently provides positive

benefits. Mr. Alaywan's more extensive life cycle study shows a net present value benefit for LEAPS in the high solar penetration case of $5.424 billion, with a benefit-to-cost ratio of 1.76:1.[94] For the high wind penetration case, the life cycle benefit would be $4.906 billion with a benefit-to-cost ratio of 1.59:1.[95]

Importantly, Mr. Alaywan demonstrates that the value of LEAPS is not confined to economic benefits alone because it will also provide important public policy and reliability benefits to the CAISO. As Mr. Alaywan explains, CAISO itself has found that a 500 MW pumped storage facility in southern California would reduce the renewable energy needs by a net of 323 MW under the high solar penetration case, and by 188 MW in the high wind penetration case. Mr. Alaywan testifies that this reduction in renewable generation would meet California's RPS targets while saving California's consumers $73 million under the high solar case, and $44 million under the high wind sensitivity—for year 2026 alone. Assuming these results are representative of all years, it would mean $226/kW-year and $234/kW-year of annual revenue requirement savings for the high solar and wind sensitivity cases, respectively.

Mr. Alaywan further identifies several ways that LEAPS will enhance grid reliability. These reliability benefits include adding essential capacity to southern California's local capacity resource ("LCR") area, increased load following capability, frequency response service, black start service, inertia,[96] and grid resiliency.

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[94] Exhibit No. 3 at 84.

[95] *Id*.

[96] Mr. Alaywan testifies that "inertia" is associated with the grid stabilizing capability of large generators that do not fluctuate significantly in response to frequency variations on the transmission grid. "Hydro generators have massive prime movers which have a lot of inertia, especially 500 MW hydro generators as in the LEAPS project. Hence, when a contingency occurs, and the frequency varies, they do not speed up or slow down rapidly like other generators. They continue to provide stability to the system. This gives primary response time to act and stabilize the frequency." Exhibit No. 3 at 66.

Mr. Alaywan explains that LEAPS will add valuable capacity to the southern California LCRs that will protect service reliability:

> My assessment shows that the proposed LEAPS project will allow the San Diego-Imperial Valley area to serve their customers reliably during periods of unusually high energy demand, unexpected outages and abnormal conditions. LEAPS also provides flexibility in operating California's transmission grid by adding additional import capability to San Diego County from the north, which has limited connectivity to the rest of the CAISO grid. In summary, my analysis demonstrates that LEAPS provides consumer benefits as an LCR resource and transmission reliability project. The value of the LCR capacity benefit is $6.31 kW-month based on 500 MW generation, and results in an annual benefit of $38 million.[97]

Mr. Alaywan goes on to explain how LEAPS will enhance grid reliability by providing essential load following and frequency response capability, and black start services, which he estimates to be worth a combined $50/kW-year,[98] which translates into an annual benefit of $30 million.[99]

Finally, Mr. Alaywan explains that LEAPS can play an essential role in grid "resiliency," which is a concept that encompasses mandatory NERC reliability criteria under Section 215 of the Federal Power Act,[100] and attributes that contribute to the robustness of the bulk electric system to respond to service disruptions.[101] As the Commission recently explained, resiliency generally means "[t]he ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly

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[97] *Id*. at 33.

[98] *Id*. at 77.

[99] *Id*.

[100] 16 U.S.C. § 824o (2012).

[101] *Grid Reliability and Resilience Pricing*, 162 FERC ¶ 61,012 (2018).

recover from such an event."[102] The inertia provided by large-scale pumped storage resources like LEAPs can serve a critical role in supporting grid resiliency.

For example, Mr. Alaywan explains that a resilient grid requires resources that can respond quickly in the critical first few moments following a blackout such as the one that occurred in the Southwestern United States on September 8, 2011.[103] In those critical moments the system requires large generating resources with the essential telecommunications and computer equipment coupled with a fast-reacting resource that operates under "automatic generation control" to help restore the grid to the harmony that exists when frequency is at (or very close to) 60 Hertz. Mr. Alaywan explains that "[i]f frequency deviation is not corrected in a few seconds, there is a risk for the grid to become unstable which leads to a catastrophic blackout."[104]

LEAPS will provide this essential resiliency service to southern California where "the availability of rotating machines equipped with AGC is diminishing and is being replaced mainly by wind and solar (both rooftop and utility scale)."[105] Compounding the resiliency problem, the 2,246 MW San Onofre nuclear plant with its massive 150-ton turbines has been taken out of service. Huntington Beach's 452-MVAR synchronous condenser is planned to be offline starting in 2018.[106] Encina will lose 950 MW of gas-fired generation, Morro Bay's 650 MW gas plant was shut down in early 2014, and the Diablo Canyon 2,200 MW nuclear facility is

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[102] *Id*. at P 23. FERC required regional transmission organizations to file explanations with FERC regarding their approaches to ensuring grid resiliency, including whether they agree with FERC's definition.

[103] Exhibit No. 3 at 73.

[104] *Id*. at 60.

[105] *Id*.

[106] *Id*.

scheduled to retire by 2026.[107] Mr. Alaywan concludes that these developments all significantly and adversely affect the frequency response capability of the power grid, thereby posing a threat to grid reliability.

Mr. Alaywan illustrates the grid resiliency benefits that LEAPS can provide through three studies. The first study simulated frequency response for a generic 500 MW solar photovoltaic facility located at Lake Elsinore compared to LEAPS during a single large contingency—the loss of the 500 kV Southwest Power Link transmission line, which serves as the major import path for SDG&E. Southwest Power Link is considered by CAISO to be one of the greatest threat contingencies for the area.[108] The September 8, 2011 blackout in Southern California began when that transmission facility tripped off-line. Mr. Alaywan's first study shows that with LEAPS, the frequency would deviate 77% less compared to the system with a new 500 MW solar photovoltaic facility.

Mr. Alaywan's second reliability study compared the frequency response pre-and post-LEAPS upon the loss of the same 500 kV Southwest Power Link transmission line for three existing generators in the SDG&E area: (1) a 500 MW solar photovoltaic facility connected to the Drew substation, (2) the 950 MW Encina combined cycle generating facility, and (3) the 45 MW El Cajon peaking gas turbines. As summarized in his Table 12, frequency excursions caused by the transmission line outage are 12% to 18% lower with LEAPS in service than without it. Also, with LEAPS, positive frequency deviation is 3% to 26% lower than without

[107] These generating capacity losses will be partially offset by the 500 MW Carlsbad gas-fired peaking plant which is expected to achieve commercial operation by the end of 2018. *See* NRG: Carlsbad Energy Center, *available at*: http://www.nrg.com/generation/projects/carlsbad-energy-center.

[108] For example, EDF Renewable Energy recently signed a long-term power sales contract with SCE to sell the output from a new 500 MW solar photovoltaic facility to be developed near Joshua Tree National Park.

LEAPS. Importantly, with LEAPS the frequency settles at a value closer to the initial frequency and reaches the initial steady state more quickly.

As a further illustration, Mr. Alaywan shows how LEAPS would help to stabilize the El Cajon power station from the loss of the Southwest Power Link line. His study shows the El Cajon gas turbine frequency dipped by 0.222 Hertz in the pre-LEAPS case, but in the post-LEAPS case its frequency dipped by just 0.192 Hertz or 14% less with LEAPS in-service, and the frequency of the natural gas generating plant stabilized in 8 seconds with LEAPS in service. Without LEAPS, El Cajon would take 20 seconds to stabilize. He found similar benefits for the Drew 500 MW photovoltaic generating station where the frequency dipped by 0.155 Hertz in the pre-LEAPS case, but just 0.136 Hz in the post-LEAPS case—a 12% improvement with 4% improved stabilization time. The frequency impact on the Ocotillo wind generation facility would also be lessened with improved stabilization time. All of these examples of grid resiliency benefits underscore the critical relationship to reliability—faster recovery times equal reliability improvements that may avoid future blackouts.

Mr. Alaywan points out that his study does not attribute a dollar value to these difficult to quantify resiliency benefits. It is, after all, difficult to estimate what a blackout ultimately costs. Adding a resource that can quickly help to stabilize the power grid or potentially avoid a blackout is undoubtedly a valuable benefit.

There are other difficult to quantify benefits of a fast-responding resource like LEAPS. Mr. Alaywan provides several examples, including the ability for the CAISO to avoid "reliability must run" payments to keep uneconomic resources in service, the ability to firm-up intermittent renewable generation, a contribution to demand response (through LEAPS's ability to reduce electric demand), and reduced renewable generation integration costs. These and the other

benefits quantified by Mr. Alaywan and the CAISO confirm that LEAPS is a meritorious addition to the power grid that should be studied as a transmission facility in the transmission planning process.

C. The Commission's Comparability Policy Requires CAISO to Study LEAPS in its Transmission Planning Process in the Same Way that it Studies Other Transmission Facilities

Order 1000 requires transmission solutions to be studied comparably to each other,[109] and even non-transmission alternatives must be studied in the same way.[110] Nevada Hydro has introduced LEAPS into the TPP on five previous occasions, but in none of them has CAISO studied LEAPS comparably to transmission solutions. The CAISO has not explained its findings that LEAPS was unneeded in those prior planning cycles, nor reconciled those decisions with its nearly simultaneous letters and pleadings to the CPUC cited above urging that large-scale pumped storage is needed to "allow for the reliable operation of a highly dynamic grid," to integrate and balance the enormous amounts of renewable energy flowing over California's interstate transmission lines, and thereby protect the public from being "harmed."

As Mr. Alaywan explains, CAISO's studies of a "LEAPS-like" 500 MW pumped storage generating facility, "hypothetically" located in southern California between SCE and SDG&E, have applied elements of the TEAM analysis to find the facility to be beneficial to the power grid, but the studies all stopped short of a full benefits analysis. None considered the full reliability or grid resiliency benefits of LEAPS (or a facility like LEAPS) as Mr. Alaywan has done. Indeed, as mentioned, CAISO's most recent "unified planning assumptions" for the 2017-2018 planning cycle treat electric storage as an "alternative" to transmission, presumably to be

[109] Order No. 1000, FERC Stats. & Regs. ¶ 31,323, at P 157.

[110] Order No. 1000-A, 139 FERC ¶ 61,132, at P 765.

studied in the same manner that CAISO has examined pumped storage in the studies described above.

Nevada Hydro has introduced LEAPS into the CAISO transmission planning process once more for the upcoming 2018-2019 cycle. As explained above, LEAPS has all of the characteristics of a wholesale transmission facility as found in *Western Grid* and further described in the *Storage Policy Statement*. As Mr. Alaywan further explains, CAISO's methodology supports the conclusion that LEAPS can conservatively provide over $5 billion of ratepayer benefits during its anticipated lifespan. Given this, the Commission should clarify that CAISO must study LEAPS comparably to other transmission facilities by examining the reliability, public policy and economic transmission needs that LEAPS could solve. Given that Mr. Alaywan simply completed the CAISO's work, it is reasonable to expect that CAISO will select LEAPS as a transmission solution to be incorporated in its 2018-2019 transmission plan, thereby becoming eligible for full cost of service rate recovery through the TAC. In this manner, LEAPS would obtain the "policy decision" that CAISO has suggested to support the development of the large-scale pumped storage resource it says it needs to manage the many challenges California faces to maintain reliable service to consumers in the years to come.

CAISO has found the need for large scale pumped storage to protect customers and has found that a project identical to LEAPS would be economical and provide necessary grid reliability benefits. If the Commission grants Nevada Hydro's Petition, but CAISO rejects LEAPS from its transmission plan, the Commission should require CAISO to file an explanation of its reasons in this docket for the Commission's review.

V. CONCLUSION

For the foregoing reasons, Nevada Hydro respectfully requests the Commission to declare that: (1) the Lake Elsinore Pumped Storage facility is a wholesale transmission facility

under the specific facts presented here and the criteria established in the *Storage Policy Statement*, and (2) LEAPS will be entitled to cost recovery under the CAISO's Transmission Access Charge. Nevada Hydro has introduced LEAPS into CAISO's recently-begun 2018-2019 transmission planning cycle and, therefore, respectfully requests the Commission to give prompt attention to the Petition so that its ruling can be implemented during the current planning process.

Respectfully submitted,

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The Nevada Hydro Company, Inc.

March 9, 2018

EXHIBIT 1

California ISO
Shaping a Renewed Future

California Independent System Operator Corporation

Steve Berberich
President & Chief Executive Officer

July 21, 2015

California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Commissioners,

As you know, California is experiencing unprecedented changes in how electricity is generated, delivered and consumed. As increasing amounts of renewable resources come on line, we are encountering new challenges for operating those resources most efficiently. We are already seeing certain times of day when more renewable energy is being generated than there is demand to use it. The Commission and the California ISO have both recognized that increased reliance on renewable resources requires thoughtful changes in policy and innovations in technology.

To this end, the ISO, the Commission and stakeholders have worked together within a number of forums to facilitate the changes necessary to lead the way to a reliable, efficient, low-carbon grid. This collaboration has included joint efforts, such as the Energy Storage Roadmap, and increased alignment in the ISO, Commission and Energy Commission planning and procurement processes.

In the Commission's current LTPP, the ISO has identified over-generation and ramping concerns associated with increased renewable generation. In the spring of 2015, changes to the net load curve outpaced expectations and significant renewable generation additions scheduled for 2016 and 2017 will only expedite the need for fast-ramping and flexible resources to balance the grid that also mitigate over generation conditions.

To meet these growing needs, the ISO and the Commission must be prepared to implement solutions that will allow for the reliable operation of a highly dynamic grid. Energy storage, with its unique ability to both consume excess renewable energy and to quickly inject clean energy back onto the grid to meet ramping and peak demand needs, has the potential to be a cornerstone of the new electric network.

Pumped energy storage, in particular, can be constructed at large scale, with characteristics that are necessary to meet our grid's over-generation and ramping needs. The ISO has begun a preliminary analysis of the benefits of large-scale pumped storage in regards to ramping and curtailment risk based on our 2014 LTPP modeling, and the results are promising. The ISO intends to further incorporate this initial work into its 2015-2016 transmission planning process. The ISO would be pleased to present these results in the context of the Commission's current LTPP in order to move the discussion forward.

In addition, the ISO intends to conduct further study leveraging updated LTPP and TPP standard planning assumptions and scenarios to analyze the benefits of large-scale pumped storage. The intent is to provide a solid, empirical basis to review the benefits of large-scale pumped storage to meet over-generation, ramping and other system needs in the in the 2016 LTPP. The ISO looks forward to sharing this study with the Commission and to using the results to inform potential procurement in the 2016 LTPP.

Please feel free to call me if you would like to discuss this further.

Sincerely,

Steve Berberich
President and Chief Executive Officer

EXHIBIT 3

Exhibit No. 3

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Nevada Hydro Company	)	Docket No. EL18-___-000

AFFIDAVIT OF ZIAD ALAYWAN P.E.
IN SUPPORT OF
NEVADA HYDRO COMPANY, LLC
PETITION FOR DECLARATORY ORDER

Contents

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address

A. My name is Ziad Alaywan. I am the founder, President and Chief Operating Officer of ZGlobal Inc. Located on 604 Sutter Street, suite 250, Folsom, CA 94630. I have been retained by Nevada Hydro Company, LLC ("Nevada Hydro") as a consultant on energy, operational, economic, regulatory, and technology issues in connection with its Lake Elsinore Advanced Pumped Storage ("LEAPS") project.

Q. Please describe your relevant experience.

A. I was employed by the Pacific Gas & Electric Company ("PG&E") between 1987 and 1996. From 1990 through 1996, I managed PG&E's real-time grid operations for the Northern and Central California Electric Grid. I was a member of PG&E's "7 x 24" operation staff where I served as a Transmission, Intertie Scheduler and Generation Dispatcher, as well as a Manager of Real Time Operations, of the PG&E Control Area, which during that time had a peak load of 18,000 MW.

In 1996, I joined the State of California Governor's office team focusing on implementation of California Assembly Bill 1890 that legislated the creation of the California Independent System Operator, Inc. ("CAISO"). As one of the first two interim CAISO employees, my efforts focused on the development and implementation of the First Tariff and subsequent Tariff amendments mainly regarding the CAISO's Bidding, Ancillary Services Pricing, Firm Transmission Rights, Scheduling, Pricing, Dispatch, and Settlements System. In addition, I was responsible for the Reliability Must Run, Transmission Contracts and Scheduling, Transmission Access Contract and Metered Subsystem. Subsequently, when the CAISO was formed in May 1997, I became a staff member and continued my responsibilities to oversee a $150 million budget

to implement the CAISO market, settlements, and dispatch systems. My responsibilities included obtaining certification from the North American Electric Reliability Corporation ("NERC") to combine the California investor-owned utility ("IOU") systems—which in addition to PG&E, included Southern California Edison Company ("SCE") and San Diego Gas and Electric Company ("SDG&E")—into a single Balancing Authority Area. I worked with the Federal Energy Regulatory Commission ("FERC") and the California Public Utilities Commission ("CPUC") to obtain certification to start the CAISO's wholesale energy markets. I successfully led the certification of the CAISO by FERC, the three inventor-owned utilities and the State and subsequently the launch of the ISO on March 31, 1998.

From 1998 to 1999, I was the Director of CAISO Market Operations responsible for the ISO market design, implementation and operation. From 1999 through 2001, I was the CAISO Managing Director of Engineering and Operations where I was responsible for all grid operations planning, including "reliability must run" generators, and the day-to-day operation of the transmission system and the wholesale power market under CAISO control.

During the period 2002 through 2005, I was the Managing Director of Market Operations, where I was responsible for the initiation of the CAISO market re-design after the California energy crisis of 2000 and 2001. That re-design included reforms to the energy and ancillary services markets, new congestion management protocols, the treatment of reliability must run generators, scheduling of generation, and the real-time and day-ahead markets, including settlements, billing, and metering functions.

In 2005, I founded ZGlobal Inc. My company provides power engineering and energy solutions for a wide sector of clients. Among other things, ZGlobal performs economic and reliability analyses for transmission, distribution and generation assets across the western

interconnection. I hold a Bachelors and a Master's degree in Electrical Engineering, graduating Summa Cum Laude with post-doctorate work in HVAC Power System Applications, Optimization, Production Model, Unit Commitment, and Power Economics from Montana State University. In 2002, I completed the Executive Management Program at the Haas School of Business, University of California at Berkeley. I am registered as Professional Engineer in the State of California and a Senior IEEE Member. Examples of my numerous publications and expert testimony are set forth in Exhibit NHC-E.

II. PURPOSE OF TESTIMONY AND CONCLUSIONS

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to support Nevada Hydro's petition for a declaratory ruling that, based on the facts present here, the proposed LEAPS project is a wholesale transmission facility consistent with the Commission's findings in its *Western Grid Development, LLC*[1] decision and is, therefore, entitled be studied as such in CAISO's annual transmission plan and included in the CAISO's cost-based system-wide transmission access charge for recovery of its annual cost of service revenue requirement. My analysis is guided by FERC's policy clarifications in its January 19, 2017, Policy Statement called "Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery" ("*Storage Policy Statement*" or "*Policy Statement*").[2]

Q. What do you conclude?

A. LEAPS will be a wholesale transmission facility as FERC defined it in *Western Grid* and the *Storage Policy Statement* because:

[1] 130 FERC ¶ 61,056 (2010).

[2] 158 FERC ¶ 61,051 (2017).

(a) LEAPS will transport stored (not *new* energy) that is necessary to serve CAISO customers,

(b) LEAPS will provide a number of transmission and grid reliability services that are necessary for the operation of the CAISO transmission system, such as voltage support, a new transmission path to the Los Angeles basin and San Diego load centers, frequency regulation and balancing services.

(c) LEAPS will provide transmission network services by moving power flow into SCE and SDGE load pockets if CAISO deems it necessary,

(d) LEAPS will stand ready to provide these services when directed to do so by the CAISO in the same manner as a California "Participating Transmission Owner" ("PTO). In fact, Nevada Hydro intends to enter into the CAISO's standard PTO and "transmission control" agreements as set forth in its Tariff. Nevada Hydro will have full responsibility to operate and maintain LEAPS to ensure that it is ready to perform all of the transmission and grid support services that it is capable of providing; and

(e) Nevada Hydro will utilize a certified Scheduling Coordinator and will bid LEAPS at its marginal cost into the CAISO Markets to ensure *no* market distortion. Moreover, Nevada Hydro will credit any and *all* market revenues that it receives to its cost of service revenue requirement that are incidental to LEAPS transmission and grid support services. Nevada Hydro will file a cost-based revenue requirement at a future time for Commission review and acceptance.

Q. Please elaborate on why is LEAPS a transmission facility?

A. In addition to the fact that LEAPS is contemplated to operate exactly as described in the *Western Grid* decision and FERC's *Storage Policy Statement*, there are other attributes that qualify

LEAPS as a transmission asset. For example, the following elements are also transmission assets since they play a key role in facilitating transmission of energy from one location to the other while allowing for a reliable, efficient and resilient grid:

i) Capacitors and Reactors: These devices are used in series and shunt compensation techniques to regulate transmission system voltage and stability. Capacitors and reactors are used extensively on the AC transmission system, particularly in the west with its long transmission lines. When transmission voltages are low, capacitors are switched on to increase the voltage level. When transmission voltages are high, reactors are switched on to reduce the voltage level.

ii) FACTS: "Flexible AC Transmission Systems" or FACTS refers to a group of resources used to overcome certain limitations in the static and dynamic transmission capacity of electrical networks. The IEEE defines FACTS as alternating current static controllers to enhance control ability and power transfer ability. The main purpose of these systems is to supply the network as quickly as possible with stored capacitance and inductive energy to ensure transmission quality and the efficiency of the power transmission system. FACTS work like capacitors and inductive devices by storing energy from the grid and releasing the energy when it is needed for reliability. FACTS provides the grid:

- Fast voltage regulation,
- Increased power transfer over long AC lines,
- Damping of active power oscillations, and
- Controls the flow of energy in meshed systems.

FACTS thereby significantly improves the stability and performance of existing and future transmission systems. With FACTS, grid operators are able to utilize their existing

transmission networks better, substantially increase the availability and reliability of their line networks and improve both dynamic and transient network stability while ensuring a better quality of supply. FACTS devices give the grid more than voltage regulation, it also allows grid operators to re-route or increase power flow by changing the power angle, damping power oscillations.

iii) Phase shifting transformers: Phase shifting transformers (PSTs) have similar functions as the FACTS devices and are also used to re-route or increase power transfers by changing the power angle.

LEAPS comprises a combination of transmission lines (wires), reversible pumps, phase shifting transformers, substations and other equipment. LEAPS and its associated equipment serves the same functions as the capacitors, reactors, FACTS, and PSTs, all in one and more. LEAPS increases and decreases voltages. It is able to re-route or increase power flow by changing the power angle and damp power oscillations using its PSTs. In addition, LEAPS provides frequency control, and its 37 miles of transmission lines provides a new path for delivering stored energy into the load pocket, thus moving stored energy from one location to another.

LEAPS is unlike a generator because it does not produce any *new* electrons or *new* watts to the grid. Like capacitors and reactors located at substations, it stores energy from the grid for use by the grid at a later hour as needed by grid operators to ensure reliability and improve the efficiency of the transmission network. In this way, LEAPS produces net energy of zero or less into the grid.

In addition, LEAPS serves an important role on electric power systems by improving system-wide efficiency and reliability and allowing grid operators to better balance the system in an era of increased resource intermittency and decreased capacity resources that provide grid

resiliency. LEAPS will transmit stored and already purchased energy, to retail loads via two new transmission paths (wires) and will quickly react to contingencies. It will provide these reliability functions as a transmission asset without producing any new watts to the grid similar to shunt capacitors, reactors, FACTS and PSTs.

Given these characteristics, LEAPS is a transmission facility that FERC, other ISO's and utilities have considered as transmission facilities.

Q. What specific reliability benefits will LEAPS provide?

A. As demonstrated through specific analyses described in this affidavit, I found that LEAPS provides multiple benefits to support grid resiliency, including:

(a) Voltage regulation to manage high and low voltages,

(b) A new transmission path to serve retail load in the Los Angeles basin or San Diego,

(c) Ability to re-route energy flow across southern California through its PSTs,

(d) Reduced curtailments of renewable energy by storing excess energy during over-generation situations,

(e) Flexible capacity by being able to instantly dispatch stored energy to the grid. LEAPS' stored energy is not dependable on gas storage supply or weather conditions and its highly predicable,

(f) Ability to reduce the magnitude of frequency deviation and the number of frequency oscillations on the CAISO grid during an outage, and

(g) Over 200 MW of stored inertia to the CAISO grid during an outage.

Q. What economic benefits does LEAPS provide to ratepayers?

A. To quantify the LEAPS' benefits to ratepayers, I have applied the CAISO's Transmission Economic Assessment Method ("TEAM") approach to evaluate whether LEAPS' overall benefits

outweigh its cost. TEAM is used by CAISO to evaluate whether a proposed transmission facility has economic benefits to costs to include in its annual transmission plan. Using the CAISO software model, data and benefit to cost assumptions where available, I have quantified the benefits of LEAPS for the five categories of service benefits that CAISO examines. I have found that LEAPS will (a) provide a life cycle expected net present value benefit-to-cost ratio (BCR) of **1.76:1** in the high solar penetration case, and (b) provide a life cycle expected net present value benefit-to-cost ratio of **1.59:1** in the more conservative high wind penetration case. The solar case shows more value because CAISO is forced to curtail generation more often during peak daylight hours and pay the generators for curtailing them. In both cases, the ratios are conservative because they do not take into account several valuable services that are difficult to quantify. In my opinion, these robust benefits ranges would justify building LEAPS as transmission assets that can both provide local capacity reliability benefits in San Diego and provide a mechanism to store renewable energy that was already paid by the ratepayers for later use while lowering the overall energy cost to ratepayers. I will describe below each benefit and cost issue that are included in my TEAM analysis.

Q. Is there any benefit that you would like to highlight?

A. Yes. One overwhelming LEAPS benefit is its ability to be an essential, predictable, flexible and dependable tool to ensure grid resiliency because it will be able to relieve over-generation by renewable energy, transmit energy to relieve major transmission constraints, provide flexibility independent of gas-fired generation, provide much needed frequency and inertia response in an era where these services are diminishing, and help maintain transmission frequency at approximately 60 Hertz ("Hz"). These benefits have led CAISO to call repeatedly for the construction of large-scale pumped storage to manage over-generation by non-controllable

renewable resources, which poses a grid reliability problem.

A second major benefit is LEAPS' ability to reach the State's renewable portfolio standard ("RPS") goals at lower cost by reducing the quantity of overbuild needed to reach its 50% RPS target. Less renewable capacity is required to be built because LEAPS is able to store excess renewable energy during over-generation and dispatch the stored energy during other hours when that renewable energy may not have been produced. Thus, based on the facts present in the CAISO region, LEAPS provides dramatic benefits to ratepayers by reducing the overall cost for procurement of solar and wind capacity to achieve the State goals. This renewable capacity cost savings is quantified as one of the categories of LEAPS' benefits in my TEAM analysis.

In sum, LEAPS will operate as a transmission facility and will provide important grid support services to help maintain reliability, balance the grid, and integrate renewable generation. It will do so economically, without distorting CAISO Markets and will provide a grid management tool that the CAISO has called for on a number of occasions. LEAPS provides positive grid benefits, even when applying conservative assumptions to CAISO's TEAM analytic tool for selecting transmission projects for cost recovery through its transmission access charge. For all of these reasons FERC should find that LEAPS must be studied as a transmission facility in a manner comparable to other transmission assets that provide reliability, public policy and economic benefits and are eligible for inclusion in CAISO's transmission access charge.

III. THE LEAPS PROJECT

Q. Please describe the proposed LEAPS project.

A. The proposed LEAPS project will be comprised of a 500 / 600 MW advanced pumped storage facility, two new twenty-seven mile 500 kV interconnecting transmission lines, two new 500 kV substations, three new 500/230 kV transformers, three new phase shifting transformers,

and one new 10-mile 230 kV transmission line. One 500 kV line will interconnect with the transmission network of SCE and the other will interconnect with the transmission network of SDG&E.[3] These facilities will be located approximately midway between Los Angeles and San Diego at Lake Elsinore, California. Lake Elsinore, which is the largest natural lake in southern California, will serve as the lower reservoir for the proposed facility. The Decker Canyon reservoir, which is to be constructed above the crest of the Elsinore Mountains, will serve as the upper storage reservoir of the LEAPS project. The Decker Canyon Reservoir will be approximately 9,500 feet southwest of Lake Elsinore at an elevation of approximately 2,792 feet above mean sea level.

The proposed facility will have an installed discharging capacity of approximately 500 MW and a variable charging pumping capacity of 600 MW provided by two single-stage reversible pump-turbine units operating under an average net head of approximately 1,484 feet. The total energy storage available will be approximately 6,000 MWh per day, allowing for 10 hours of discharge of the stored energy at the full discharge capacity of 500 MW. The corresponding charging / pumping requirement will be 12 hours at the full plant pumping capacity of 600 MW, with additional required pumping occurring on Saturday and/or Sunday if a weekly cycle is used.

The pump-turbine and motor-generating units and associated mechanical and electrical equipment will be located below ground, immediately adjacent to Lake Elsinore, at the foot of the Elsinore Mountains. Stored energy will be released and transformed underground to 500 kV, and transmitted to the surface by way of oil-filled cables along the side of the elevator shaft. LEAPS will be interconnected to the grid at separate interconnections with SCE and SDGE.

[3] LEAPS' two 500 kV lines, however, will not connect directly with each other and, therefore, will not create free-flowing ties between SDG&E and SCE.

The upper reservoir will have a water surface area at full capacity of approximately 100 acres; the reservoir will be fully lined and constructed so that it is isolated from surface runoff and groundwater. An intake/outlet structure located in the upper reservoir will interconnect the reservoir with the reversible pumps through a single penstock, approximately 25-feet in diameter, bored into and through the Elsinore Mountains. A single-line electrical diagram is attached at Exhibit NHC -A.

Q. Please briefly describe the services that LEAPS will be able to provide.

A. LEAPS will be an electric storage resource with the ability to both charge and discharge electricity, and provide transmission and a variety of grid support services to CAISO. These services include reactive power (*i.e.*, VAR) support, load and resource balancing services (*i.e.*, regulation-up and regulation-down services), moment-to-moment load following service, spinning reserve service, black start service, and several additional grid support services. LEAPS will be able to switch from providing one service to another almost instantaneously.

Q. What is the projected cost of the LEAPS project and its forecasted annual revenue requirement?

A. Nevada Hydro currently estimates the project's total cost to be approximately $2 billion. I have utilized the CAISO TEAM study assumptions to the extent possible: a 50-year project life, a 50%/50% debt-to-equity ratio, 5.0% debt rate, 11% nominal return on equity ("ROE"), 29.65 % state and federal taxes, 1.85% inflation[4] and 0.1% G&A.[5] The resulting levelized real revenue requirement is estimated at $177 million annually.

[4] Inflation Rates: https://inflationdata.com/inflation/inflation_rate/currentinflation.asp http://www.usinflationcalculator.com/inflation/current-inflation-rates/

[5] This include fixed maintenance cost only. Variable maintenance cost of 3$/MWH is included in the Production cost modelling.

IV. FERC's *STORAGE POLICY STATEMENT*

Q. What does the *Storage Policy Statement* provide?

A. The *Storage Policy Statement* "provide[s] additional guidance regarding issues that arise for electric storage resources seeking to recover their costs through both cost-based and market-based rates concurrently."[6] FERC further stated that it "also believe[s] that clarification regarding our *Nevada Hydro* and *Western Grid* precedent is warranted due to potential confusion with respect to that precedent."

Q. What guidance did FERC provide on cost recovery by storage resources?

A. The *Policy Statement* provides three options for electric storage facilities to obtain cost recovery on a case-by-case basis: (1) market-based rates for the sale of electric energy, capacity and ancillary services under pre-existing policy, (2) cost-based rate recovery of the full revenue requirement for electric storage facilities, or (3) a hybrid approach whereby the cost-based revenue requirement is reduced by market revenues to assure that there is no double recovery of costs from ratepayers. Applicants must show that their storage facilities will be "wholesale transmission facilities" like the storage facility in *Western Grid*, that they will follow operating procedures like PTOs that will not inadvertently cause CAISO to become a market participant, and that there are protections against the storage operator over-recovering its cost-based revenue requirement through participation in wholesale power markets.

Q. Why did FERC issue the *Policy Statement*?

A. The *Policy Statement* reconciled conflicting precedents where FERC denied Nevada Hydro's petition to recover the costs of the LEAPS project in transmission rates,[7] whereas FERC

[6] *Storage Policy Statement* at P 9.
[7] *Storage Policy Statement*, 158 FERC ¶ 61,051 at PP 3, 9.

allowed such cost recovery in *Western Grid*.[8] FERC rejected Nevada Hydro's rate proposal over ten years ago because it would have given CAISO operational control and thereby raised potential conflicts with other market participants. In the subsequent *Western Grid* case—in which I provided a supporting affidavit—FERC ruled that battery storage used to transport stored energy for ultimate delivery to retail customers and to provide voltage support and transmission overload protection served as "wholesale transmission facilities subject to the Commission's jurisdiction if operated as described by Western Grid."[9] FERC found that Western Grid solved the CAISO's market participant dilemma by offering to operate its storage facility at CAISO's direction like the PTOs whereby Western Grid retained all operating functions, including maintenance, communication and system emergencies, and ultimate responsibility for energizing the battery array.[10] FERC stated that Western Grid, not CAISO, would be responsible for buying power to charge its battery, and for physically operating the batteries when they were being charged or discharged.[11] "Importantly," FERC added, "Western Grid will operate the Projects, at the CAISO's direction, only as transmission assets. They will be operated in a way that is similar to the operation of other transmission assets (e.g., capacitors that address voltage issues or alternate transmission circuits that address line overloads and trips)."[12] FERC also stated that "just like other transmission assets, and unlike traditional generation assets, Western Grid will not retain revenues outside of the transmission access charge, and it will credit any revenues it may accrue as a result of charging/discharging the Projects through its PTO tariff."[13]

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[8] *Id.* at P 4.

[9] 130 FERC ¶ 61,056 at PP 43.

[10] *Id*. at P 45.

[11] *Id*.

[12] *Id*.

[13] *Id*. at P 43.

Q. Does LEAPS fit FERC's definition of a "wholesale transmission facility" as described in *Western Grid*?

A. Yes. Just like the battery storage project in *Western Grid*, LEAPS "will transport stored energy to serve retail load, similar to a transmission line, and will provide voltage support and other reliability services that are necessary for operation of the transmission system."[14] In fact, Western Grid argued that its similarity to pumped storage supported its request to be treated as a wholesale transmission facility "because they are not a net producer of electricity."[15] LEAPS will function to store energy purchased from CAISO's wholesale markets and used to pump water into its reservoir to be released later to provide energy that will be converted back to electricity as needed. As such, LEAPS will convert electrical energy to potential energy and back again to electricity with no net increase to electric production.

Moreover, LEAPS will, via its energy storage capability, be able to transmit electricity between SCE and SDG&E using LEAPS 37 miles of new transmission (wires) to relieve transmission constraints. Existing transmission choke points make SCE and SDG&E two of the biggest load pockets in California where prices can rise significantly higher than those prevailing outsides of the San Diego and Los Angeles basins. Thus, at CAISO's direction, Nevada Hydro will be able to release energy from LEAPS for delivery to either load pocket to alleviate the constraint. In addition, LEAPS will be able to provide another pathway to move electricity when network transmission facilities are out of service. As such, LEAPS will be able to serve a critical transmission function.

[14] *Id.* at P 18.

[15] *Id.* at P 20.

LEAPS will also be able to provide a variety of grid support services which the CAISO has recognized in its analyses of the potential benefits of adding 600 MW of pumped storage hydroelectric capability to southern California.[16] These services include reactive power (*i.e.*, VAR) support, load and resource balancing services (*i.e.*, regulation-up and regulation-down services), moment-to-moment load following service, spinning reserve service and black start service. LEAPS will be able to switch from providing one service to another almost instantaneously. Other grid support services that CAISO has recognized pumped storage facilities like LEAPS can provide include:

- Renewable generation integration (*i.e.*, balancing variability and over-generation)
- Frequency regulation
- Power system stability
- Load following
- Contingency reserves
- Inertial response
- Cycling and ramping protection of thermal generation
- Relieving transmission congestion

In providing transmission and transmission support services, LEAPS will differ from generators that obtain cost-based revenues as "reliability must run" units. Those units operate to provide capacity to the transmission grid primarily in circumstances when capacity shortage conditions exist. LEAPS, in contrast, will operate during all types of transmission system conditions to support grid reliability. That includes during periods of over-generation by

[16] California ISO, *ISO 2016-2017 Transmission Planning Process, Supplemental Sensitivity Analysis: Benefits Analysis of Large Energy Storage* (2018).

renewable resources when CAISO is currently forced to issue directives to curtail output and pay those generators for doing so. Importantly, LEAPS will be able to quickly switch from absorbing excess electricity in its pumping mode to producing electricity from stored energy when transmission system conditions require, such as during the evening ramp when renewable resources are providing less electricity. I will discuss these grid support services and quantify the value they provide later in my testimony when I discuss the CAISO's benefits analysis of large-scale pumped storage.

For the moment, it is important to note that the flexibility to provide the foregoing long list of grid support services contrasts with the battery storage facility in *Western Grid*, which proposed to operate to provide voltage support and to relieve thermal overloads.[17] LEAPS will be able to address those worrisome reliability conditions, and many others as well. Indeed, *no other generating resource packages all of these services and grid benefits* in the way that a large pumped storage facility like LEAPS can. Although battery storage can do some of these things, it cannot do all of them, and with the largest battery facilities being in the 15-40 MW range, those facilities simply cannot substitute for the grid resiliency benefits of a pumped storage project like LEAPS.

Q. Has FERC found LEAPS to be a transmission asset?

A. Yes. The Commission has ruled that LEAPS meets the statutory definition to be classified as an "advanced transmission asset" under sections 1223 and 1241 of the EPAct 2005.[18] In Section 1223, Congress stated that "the Commission shall encourage as appropriate the deployment of advanced transmission technology."[19] Advanced transmission technology is defined in EPAct 2005 as "a technology that increases the capacity, efficiency, or reliability of an existing or new

[17] 130 FERC ¶ 61,056 at P 47.

[18] *The Nev. Hydro Com., Inc.*, 117 FERC ¶ 61,204, at P 27 (2006).

[19] Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594, 953-54 (2005).

transmission facility."[20] EPAct 2005 includes "energy storage devices" like pumped storage hydro facilities as advanced transmission technology.[21] LEAPS will provide classic transmission services, as I explained above, and will also enhance the capabilities of the existing transmission network as contemplated by EPAct 2005. Thus, FERC correctly found that LEAPS will be a transmission facility many years ago.

Q. Are there any other reasons why you believe LEAPS will be a transmission facility?

A. Yes. LEAPS will have physical characteristics similar to large capacitors that have historically been classified as FERC-jurisdictional transmission facilities.

As the Commission agreed in *Western Grid*,[22] it has treated facilities that operate and are physically constructed like LEAPS, such as large electrical capacitors, as FERC jurisdictional transmission facilities. For example, in *Southern Co. Services*, 80 FERC 61,318 (1997), the Commission concluded that "reactive power sources available on the Southern system include transmission equipment such as capacitors, reactors and the natural capacitance of transmission lines." (Emphasis added.) More recently, in *Transmission Relay Loadability Reliability Standard*, Notice of Proposed Rulemaking, 127 FERC ¶ 61,175, P 18 (2009) the Commission described "specific criteria to be used for certain <u>transmission system configurations</u>," stating that such criteria "account for the presence of devices such as series capacitors and address circuit and transformer thermal capability." (Emphasis added.)

Further, as explained, LEAPS is designed to: (1) be used by the CAISO to resolve transmission and system reliability issues when the system is under over-generation conditions,

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[20] *Id*. at 953.

[21] *Id*. at 954.

[22] 130 FERC ¶ 61,056 at P 47 ("the Projects as Western Grid proposes to operate them do share some important characteristics with capacitors").

(2) maintain reliability when other transmission facilities are out of service for maintenance, and (3) provide grid resiliencies as the grid is relying more and more in intermittent resources. In such situations, LEAPS would automatically come on-line and would prevent any NERC reliability violations, or any interruption of electricity service to customers, and LEAPS would be able to provide reliability services throughout the requisite peak hours and during over-generation hours. LEAPS will perform transmission and reliability functions by providing the voltage control support or load reduction needed for the operation of the transmission system when called to do so. Also, LEAPS can be used to mitigate overloads, line trips, lines taken off for maintenance, and voltage dips of affected transmission line segments on the CAISO transmission system.

Q. How does Nevada Hydro propose to operate the LEAPS project?

A. Nevada Hydro will operate LEAPS consistent with the Commission's guidance in the *Policy Statement* to ensure that it does not adversely affect the CAISO's independence or any distortion to CAISO markets and non-discriminatory services. Nevada Hydro will operate LEAPS to provide transmission and reliability services such as voltage support, relief from thermal overload conditions, and grid resiliency support at CAISO's direction, just like Western Grid.

In the *Policy Statement* FERC cited to its experience with Western Grid as an example of an acceptable arrangement that would avoid drawing CAISO into a market participant role, and thereby compromise its independence. I testified on behalf of Western Grid in that proceeding. Western Grid committed to use its battery storage to provide grid support services, and promised that it would retain responsibility for energizing the battery, operating and maintaining it, and would retain responsibility for communications with the CAISO and responding to emergency conditions. Nevada Hydro plans to operate LEAPS the same way.

The roles and responsibilities among Nevada Hydro as a PTO, CAISO, and the other PTOs will be defined in a CAISO transmission control agreement as provided in the CAISO Tariff. Nevada Hydro will work with these parties to develop detailed operating procedures at the appropriate time. The more detailed operating procedures would address dispatch protocols, other transmission provider responsibilities, such as operating procedures that describe the role and responsibility under normal and emergency conditions, and also describe daily operating responsibilities that Nevada Hydro must perform. Nevada Hydro operating personnel have decades of utility experience, are NERC certified and, therefore, are able to perform these duties.

At a minimum, Nevada Hydro will perform the following tasks: (1) monitor status of the LEAPS project; (2) report to CAISO; (3) coordinate with the CAISO and other PTOs; (4) approve LEAPS maintenance schedules; (5) ensure protective relaying and automatic transfers are maintained; and (6) monitor flows and voltage levels. Nevada Hydro's TCA can provide that it will perform all duties associated with the daily 24 x 7 operations and maintenance of the LEAPS facility. These responsibilities would include: (1) ensuring the safe and reliable operations of LEAPS; (2) performing the operation and the maintenance of the protective relaying automatics; (3) performing all planned and forced outage reporting; (4) maintaining voltage level; and (5) complying with WECC and NERC reliability standards.

Moreover, Nevada Hydro, as a PTO, will perform the following operational activities: (1) operate LEAPS in accordance with Good Utility Practice and in a manner that ensures safe and reliable operation; (2) maintain appropriate voltage schedules; (3) provide voltage support when requested by CAISO; (4) operate LEAPS as required by the CAISO to alleviate thermal overload and voltage decay; (5) ensure that LEAPS can automatically connect to the grid upon pre-defined NERC N-1 and N-2 reliability contingencies; (6) respond if the CAISO notifies Nevada Hydro of

changes to the status of LEAPS or limitations to automatic voltage regulators or power system stabilizers; (7) maintain or change either the LEAPS voltage schedule or its reactive power schedule as appropriate; (8) notify the ISO of system conditions and coordinate switching of voltage support or phase shifter equipment; (9) notify the CAISO of events and changes that impact voltage support equipment availability or reliability; (10) de-energize the LEAPS facility; and (11) energize LEAPS as requested by CAISO.

Q. Will LEAPS participate in CAISO's wholesale power markets?

A. Nevada Hydro will use LEAPS similar to Pacific Gas and Electric Company's ("PG&E") Helms Pumped Storage project.[23] In my experience at PG&E and CAISO, this 1,200 MW pumped storage hydroelectric facility has been used for reliability response to mitigate over-voltage and under-voltage conditions in the Fresno area, to reduce transmission overloads, and respond to over-generation conditions.[24] Nevada Hydro may receive revenues for incidental energy production delivered to CAISO in connection with its reliability and transmission support services. Nevada Hydro will credit such revenues to its cost of services rates.

Q. Will Nevada Hydro retain the revenues for incidental market-based sales of electricity from LEAPS?

A. No. Nevada Hydro proposes to recover the full revenue requirement for the LEAPS project through the CAISO's TAC and to revenue credit the proceeds of sales for any energy and ancillary electric products to TAC customers. This would include any revenue from the hourly locational marginal price of electric energy produced by LEAPS, regulation services (*i.e.*,

[23] Helms Pumped Storage participates in the ISO wholesale power market; however, the project costs are included in retail rates.

[24] California Energy Commission, 2015 Bulk Storage Workshop (Nov. 20, 2015) (PG&E presentation by Michael L. Jones), available at: http://docketpublic.energy.ca.gov/PublicDocuments/15-MISC-05/TN206696_20151119T101527_PGE_Bulk_Storage_Presentation.pdf.

regulation up and regulation down service), and spinning reserve service. Nevada Hydro will credit market revenues received for the production and sale of electric energy incidental to its wholesale transmission and transmission support services.

Q. Is rate recovery through the TAC needed to ensure the construction of large scale pumped storage facilities?

A. Yes. Large-scale pumped storage hydroelectric projects must be licensed by the FERC and involve capital costs in the hundreds of millions of dollars to well over one billion dollars. The development lead time often is ten years or more. Nevada Hydro's efforts to develop LEAPS has already passed the decade mark. Although existing large scale pumped storage facilities provide extremely valuable services, they all were constructed before the Commission began its open access policies to promote electric competition. PG&E's Helms Project was the last pumped storage hydroelectric project placed into service in the Western Interconnection, but that was a very long time ago in 1984. The fact that no new large scale pumped storage facilities have been constructed since the FERC restructured the electric industry in the 1990's speaks for itself.

The Department of Energy's ("DOE") recent "Hydropower Vision" policy paper highlights the importance of hydroelectric pumped storage, but flagged uncertain rate recovery as the key barrier to new projects.[25] The Hydropower Vision report (which uses the acronym "PSH" for pumped storage hydro projects) observes:

> While PSH plants provide numerous services and contributions to the power system (a total of 20 PSH services and contributions were identified by Koritarov et al.), in existing U.S. electricity markets they typically can receive revenues only from energy, certain ancillary services (typically for regulation, spinning, and non-spinning reserves), and capacity markets. The provision of black start capability is typically arranged through a long-term contract. Most existing markets have no established mechanisms to provide revenues for other services and contributions of

[25] U.S. Department of Energy, "Hydropower Vision—A New Chapter for America's 1st Renewable Energy Resource," Section 2.7 (July 26, 2016) ("Hydropower Vision"), *available at*: https://energy.gov/sites/prod/files/2016/10/f33/Hydropower-Vision-10262016_0.pdf.

> PSH to the power grid. In contrast to competitive electricity markets, the traditional regulated utilities do not have established revenue streams for specific PSH services. The system operator typically optimizes the operation of PSH plants to minimize generation costs for the system as a whole. Therefore, in both traditional and restructured market environments, many PSH services and contributions are not explicitly monetized. Since PSH plants typically provide multiple services at the same time, it is difficult to distinguish the specific value of particular services and contributions, such as the inertial response, voltage support, transmission deferral, improved system reliability, and energy security.[26]

The Commission's *Policy Statement* is essential to removing this cost recovery barrier because of the numerous valuable services that pumped storage can provide.

Q. Can you elaborate on the need for hydroelectric pumped storage in California?

A. Hydroelectric pumped storage facilities have been the only commercially viable form of large scale electric storage. For this reason, California has an especially urgent need for hydroelectric pumped storage because of its aggressive RPS requirements. At the same time, dispatchable natural gas-fired generation is in decline, and its future is in doubt, especially in southern California where there is a question about the future operation of the Aliso Canyon natural gas storage facility[27]. Relying more on the remaining gas-fired generation for cycling and ramping will place greater stress on those generating machines, while market revenues may be inadequate to make it economic to keep them running.

Worse, California has closed all but one of its nuclear plants and the last, the 2,300 MW Diablo Canyon facility, is also set to close soon along with natural gas fired generating plants, thereby depending even more heavily on non-dispatchable renewable generation. The combined effect of more variable generation with the decline of flexible and base load generation is creating significant challenges for grid reliability. CAISO has acknowledged, hydroelectric

[26] *Id*., at Section 2.7.7 (footnote omitted).

[27] On 2/23/2018 and until 3/3/2018, CAISO issued a Restricted Maintenance Operations due to natural gas curtailments due to Aliso Canyon.

pumped storage can play a critical role in supporting the evolving power grid.

Q. Why do the CAISO Markets not provide sufficient revenue to support pumped storage?

A. First, it is not clear that infrastructure projects the size of pumped storage projects could be financed and constructed based on market revenues alone. The CAISO market is limited to energy and ancillary services, which provide uncertain revenue streams. Capacity and other reliability based services such as voltage support and black start services are done thought bilateral contracts with prices regulated by the CPUC. This market model does not monetize all of the services that pumped storage provides, as the DOE Hydropower Vision paper recognized. For instance, the California Energy Commission in 2016 market showed that net revenues for a combined cycle unit in the CAISO ranged between $11/kW-year in northern California and $22/kW-year in southern California given day-ahead and real-time market conditions.[28] These prices were well below the CEC estimated annual revenue requirement of a natural gas plant, which it placed at 166 $/kW-year.[29]

V. ANALYSIS OF LEAPS' BENEFITS

A. CALIFORNIA'S RPS POLICY

Q. Please describe California's carbon emissions policy.

A. California's policy hopes to achieve a 40 percent reduction in CO_2 emissions from 1990 levels by 2030 and an 80 percent reduction by 2050. Air quality goals include a 90 percent

[28] https://www.ISO.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf, Page 52

[29] Annual fixed costs are derived from California Energy Commission's Estimated Cost of New Renewable and Fossil Generation in California report which is published once every couple year. The annual fixed costs in this report are the average between IOU, POU and Merchant fixed costs reported in the March 2015 final staff report, Appendix E: http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SF.pdf.

reduction in emissions of nitrogen oxides from 2010 levels in some of the state's most polluted areas by 2032. Meeting these ambitious clean energy and clean air goals requires, as we have witnessed thus far, fundamental changes over the next decade and beyond.

Q. Please describe the amount of renewable energy resources in California and how they impact the need for large scale pumped storage.

A. California utilities are now required to procure 50% of their electric retail sales from eligible renewable resources by the year 2030. There is, however, a push to accelerate the achievement of 50% sooner than 2030 and possibly increase the goal from 50% to 75%, or possibly even 100%. To support achieving 40% statewide GHG reductions by 2030 and 80% by 2050, California's Integrated Resource Plan and Long-Term Procurement Plan ("IRP-LTPP") recommends a 42 MMT GHG planning target for the electric sector but also considered a more aggressive 30 MMT target to assess ratepayer cost impacts.[30]

California has another challenge because the amount of dispatchable fossil- and nuclear-fueled generating capacity is decreasing, especially in Southern California and the Los Angeles basin load pocket. The natural gas-fired generating capacity that remains faces fuel supply challenges because the main natural gas distributer, Southern California Gas Company, has faced debilitating operational challenges at its Aliso Canyon natural gas storage facility. Those difficulties have contributed to the CPUC's examination of electric storage technologies, including pumped storage, as an alternative.

Electric storage can provide a number of services to supplement or even replace transmission support services otherwise provided by natural gas-fired generation. For example, a

[30] Integrated Resource Plan and Long-Term Procurement Plan proceeding, Proposed Reference System Plan, http://cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/AttachmentA.CPUC_IRP_Proposed_Ref_System_Plan_2017_09_18.pdf.

2015 Rocky Mountain Institute study of "The Economics of Battery Energy Storage" identified 13 services provided by battery storage facilities.[31]

Q. Has the need for LEAPS changed over the years?

A. The LEAPS project has been in development for in excess of 10 years. Since the project's initial development energy policies have gone through transformational and unprecedented changes that now puts large pump storage located in the load center at more of an advantage than ever before. In 2010 the State Water Resources Control Board ("SWRCB") approved a once-through cooling ("OTC") policy that included many grid reliability recommendations made by the ISO. The Office of Administrative Law approved the policy on September 27, 2010, and it became an effective regulation on October 1, 2010. The OTC policy requires electric generators to reduce or eliminate the use of coastal or estuarine water to minimize the harmful impacts of cooling water intake structures on the environment. The OTC policy recognizes that some of these plants are critical for system and local reliability. For example, many of the plants affected by the OTC policy provide operational services needed to integrate renewable resources into the state's electric grid. Some power plant owners will repower their facilities and use dry cooling technologies to replace OTC to remain compliant with the policy, while others will retire their facilities altogether. The permanent closure of San Onofre Nuclear Generation Station in 2012 presents additional challenges to the grid especially in Southern California, which provided generating capacity and voltage support for the region.

More recently, constraints on the natural gas infrastructure in the region have limited the natural gas supply for power generation in Southern California. In the longer term, the total

[31] Rocky Mountain Institute, *The Economics of Battery Energy Storage: How Multi-Use, Customer-Sited Batteries Deliver the Most Services and Value to Customers and the Grid* (Oct. 2015). Available at: https://indico.hep.anl.gov/indico/getFile.py/access?resId=2&materialId=paper&confId=1129.

demand for natural gas for electric generation is expected to decline as newer more efficient natural gas plants replace older, less efficient gas plants, and more renewable resources come on-line to meet the state's RPS goals displacing natural gas generation.

Moreover, LEAPS is ideally located just a few miles from the now shuttered San Onofre plant and SDG&E's OTC plants. Its fuel source is independent of gas pipelines, it provides significant reliability benefits to two of the three largest load pockets in California and in the era of increasing intermittency, LEAPS provides flexible and fast ramping capacity which is becoming the most needed reliability tool for the CAISO operators. For these reasons, I conclude that the need for LEAPS has increased substantially.

B. CAISO'S TRANSMISSION ECONOMIC ASSESSMENT METHODOLOGY

Q. Does CAISO have a method to evaluate the benefits of electric transmission facilities for selection in its transmission planning process?

A. Yes. CAISO's Transmission Economic Assessment Methodology (TEAM) uses principles for economic planning. TEAM was first used by the CAISO in 2004,[32] and since then has become the "bedrock" for CAISO's evaluation of transmission projects and their alternatives to ensure ratepayer protection.[33]

Q. Please describe the CAISO's TEAM method.

A. TEAM relies on five key benefits categories:

1. **Production benefits:** Net ratepayer savings based on production cost simulation as a consequence of the proposed transmission upgrade, including energy and ancillary service benefits.

[32] http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology.pdf

[33] http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

2. Capacity benefits: The benefit of increased import capability into the CAISO BAA or a load pocket to meet a specific Local Capacity Requirement ("LCR") set by the CAISO. Decreased transmission losses and increased generator deliverability contribute to capacity benefits as well.

3. Public-policy benefits: Transmission projects can help to reduce the cost of reaching renewable energy targets by facilitating the integration of lower cost renewable resources located in a remote area, or by avoiding over-build.

4. Renewable integration benefit: Interregional transmission upgrades help mitigate integration challenges, such as over-supply and curtailment, by increased access to energy and ancillary services.

5. Reliability benefits and avoided cost of other transmission projects: If a reliability or policy project can be avoided because of the economic project under study, then the avoided cost contributes to the benefit of the economic project.

Q. Are there other important attributes of the ISO TEAM methodology?

A. Yes, TEAM has four important components: (1) the use of a full network transmission model, (2) market-based calculation of energy and ancillary services using marginal cost, (3) an uncertainty analysis, as the economic assessment is sensitive to input assumptions such as load growth and natural gas pricing, and (4) evaluation of alternatives, including non-wire alternatives, to determine the most economic, preferred solution. In addition, CAISO conducts reliability studies to validate that alternatives do not raise reliability concerns.[34]

Q. Has CAISO applied the TEAM analysis to pumped storage projects?

[34] http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf, page 3 and 4

A. Yes, within the last two years CAISO performed at least four assessments or sensitivities to quantify the benefits of bulk storage. The CAISO used the 2026 study year as the basis for its analysis.

Q. Did the CAISO comply with its TEAM methodology in conducting its study, "Benefits Analysis of Large Energy Storage"? [35]

A. Partly. Over the last two years, CAISO conducted updates to previously performed studies with at least four sensitivities for a generic 500 MW hydro pump storage in Southern California noting two known potential locations in the San Diego load pocket. Although, the CAISO sensitivities are very helpful, they fell short of performing what is done under the TEAM in five important areas: [36]

(a) the analysis was conducted for only one study year (2026),

(b)the analysis did not consider the project's benefit for avoided cost of other projects,

(c) the analysis did not quantify the "reliability" benefits category of the TEAM,

(d) the analysis was not based on a life cycle cost -benefits framework per section 2.4.1 of the TEAM, and

(f) the analysis does not incorporate uncertainty or sensitivity analysis suggested in section 5 of the TEAM.

Q. What did the CAISO conclude about the benefits of bulk storage?

A. The CAISO stated that new pumped storage resources brought significant benefits to the system, including:

[35] http://www.caiso.com/Documents/SupplementalSensitivityAnalysis-BenefitsAnalysisofLargeEnergyStorage.pdf, (2018).

[36] http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

- reducing renewable curtailment and renewable overbuild needed to meet the 50% RPS target;
- making use of the recovered renewable energy from curtailment as well as low cost out-of-state energy during hours without renewable curtailment;
- providing lower cost energy during the net peak hours in early evening and flexibility to provide ancillary services and load-following and to help follow the load in the morning and evening ramping processes; and
- lowering system production cost to serve the load.[37]

Q. What do you observe and conclude from the CAISO's analysis?

A. The CAISO has consistently found that large-scale pumped storage is needed to support the reliability, public policy and economic transmission development needs of the network under its control.

The State's energy policies of increased RPS goals and lowered emission targets, coupled with coastal gas outages, OTC, coal and nuclear plant retirements leads to less reliable operating conditions for the CAISO. The CAISO is concerned that the future resource mix will: (1) increase over-generation, (2) provide limited flexibility to respond to intermittency, and (3) have decreased capability to provide inertia and frequency response.

Q. After applying the TEAM methodology to the CAISO's study results, what are the quantified benefits for a 500 MW pump storage located between the Southern California load pockets?

A. Using the results of the CAISO's own analysis, I quantified the benefits of a 500 MW pump storage in the Southern California load pockets as shown below:

[37] http://www.caiso.com/Documents/SupplementalSensitivityAnalysis-BenefitsAnalysisofLargeEnergyStorage.pdf at , page 7.

Table 1. Summary of Benefits from CAISO's Large Energy Storage Sensitivity Analysis

Summary of Benefits from CAISO's Large Energy Storage Sensitivity Analysis for a 500 MW Pump Storage in Southern California Load Pocket	Solar Case ($Million)	Wind Case ($Million)
Sensitivity #1 - Summary of the CAISO analysis of the Updated Default Scenario (2026 Base case)	$187.8	$167.0
Basecase: Sensitivity #2 - Summary of the CAISO analysis of the Updated Default Scenario with Non - Dispatchable CHP (2026 Base case)	$217.0	$187.0
Sensitivity #3 - Summary of the CAISO analysis of the Updated Default Scenario with 2015 IEPR Mid - AAEE Sensitivity (2026 Base case)	$188.0	$168.0
Sensitivity #4 - Summary of the CAISO analysis of the Updated Default Scenario with 4-tier Curtailments Prices (2026 Base case)	$183.0	$175.0

CAISO's analysis for a 2026 study year showed that 500 MW pump storage in the Southern California load pockets had benefits to ratepayers that ranged from $217 million to $167 million. The benefits quantified included four of the five categories in the TEAM; however, this excluded TEAM benefit category #5, "reliability benefits and avoided cost of other projects." Applying these four TEAM benefit categories for all four sensitivities to my estimate of LEAPS' annual revenue requirement of $177 million results in a one-year benefit-to-cost range of 1.03:1 to 1.23:1 and 0.94:1 to 1.06:1 for the heavy solar and heavy wind sensitivities, respectively.

Table 2. Summary of 1-year BCR for ISO's Large Energy Storage Sensitivity Analysis

Summary of 1-year BCR from ISO's Large Energy Storage Sensitivity Analysis for a 500 MW Pump Storage in Southern California Load Pocket	Solar Case ($)	Wind Case ($M)
Sensitivity #1 - Summary of the ISO analysis of the Updated Default Scenario (2026 Base case)	1.06	0.94
Basecase: Sensitivity #2 - Summary of the ISO analysis of the Updated Default Scenario with Non - Dispatchable CHP (2026 Base case)	1.23	1.06
Sensitivity #3 - Summary of the ISO analysis of the Updated Default Scenario with 2015 IEPR Mid -AAEE Sensitivity (2026 Base case)	1.06	0.95
Sensitivity #4 - Summary of the ISO analysis of the Updated Default Scenario with 4-tier Curtailments Prices (2026 Base case)	1.03	0.99

Q. Can you elaborate on how you calculated the benefits summarized?

A. Yes, for instance, under Sensitivity #2, the quantified benefits from CAISO's study are presented below:

Table 3. Quantified TEAM Benefits for ISO Sensitivity #2 – Updated Default Scenario with Non-Dispatchable CHP

Sensitivity #2 - Summary of the ISO analysis of the Updated Default Scenario with Non - Dispatchable CHP (2026 Base case)			
Benefit Categories per TEAM	**Net Cost Reduction / Benefits ($M)**	**Solar Case**	**Wind Case**
California Production Cost Benefits	Net reduction in Energy Cost	$31.0	$37.0
	Net Reduction in Load Followings, Regulation and Spin Costs, and Energy Market Revenue for LEAPS	$55.7	$57.4
Capacity Benefits	LCR benefits	$38.0	$38.0
Public Policy Benefits	Reduction in RPS costs	$73.0	$44.0
	Reduction in Emission Costs	-$1.0	-$1.0
Renewable Integration Benefits	Over-generation cost reduction	$20.4	$11.6

Sensitivity #2 - Summary of the ISO analysis of the Updated Default Scenario with Non - Dispatchable CHP (2026 Base case)			
Benefit Categories per TEAM	**Net Cost Reduction / Benefits ($M)**	**Solar Case**	**Wind Case**
Reliability and Avoided Cost Benefit of other Projects	Interconnection Costs	not studied	not studied
	Avoided large transmission investments	not studied	not studied
	Reliability benefits / Grid Resiliency	not studied	not studied
Total Benefits		**$217.0**	**$187.0**
Annual Revenue Requirements		**$177.1**	**$177.1**
One Year Benefit to Cost Ratio (BCR)		**1.23**	**1.06**

As shown in **Table 3**, the benefit-to-cost ratio for 2026 ranged from 1.23:1 to 1.06:1 based on four out of the five TEAM categories that CAISO analyzed in its study. The fifth TEAM category, "reliability and avoided cost benefits of other projects," was not quantified by the CAISO. I will explain later in my testimony how I expanded the CAISO analysis to also include this benefit category, and expand the analysis over the project life cycle. I used Sensitivity #2 for my expanded analysis, which also includes an expected benefits analysis where I varied input assumptions such as natural gas prices, energy efficiencies, hydro and other important factors that can influence ratepayer benefits.

Q. Can you describe in more detail the components of each benefit category of the CAISO analysis?

A. Yes, the following is a summary of the bulk storage benefits resulting from the CAISO's study. For instance, Sensitivity # 2 found:

(a) California ISO Production Cost benefits:

i. $31 million and $37 million in reduced energy costs

ii. $55.7M and $57.4M benefit to ratepayers for revenue requirement offsets from the pump storage's net market revenue for energy, load following, regulation and spin

(b) Capacity benefits: Although no specific reliability analysis was conducted by CAISO for the 500 MW pumped storage, the CAISO noted in their study that the location of LEAPS will without any doubt qualify to provide local capacity for LCR requirements.[38] The LCR benefit is valued at $6.31 kW-month[39] which is equal to $38 million for a 500 MW pump storage.

(c) Public policy benefits:

i. RPS cost: Without pumped storage, CAISO's study indicated that an additional 1,619 MW of solar or 1,211 MW of wind will be needed in 2026 to achieve the 50% RPS goal. After adding the 500 MW pumped storage facility in Southern California, however, CAISO's study showed that this RPS requirement would be reduced from 1,619 MW to 1,296 MW in the high solar penetration case, and from 1,211 MW to 1,023 MW in the high wind penetration case. Therefore, the net reduction of RPS nameplate capacity is 323 MW of solar or 188 MW of wind respectively, which is 20% less solar generation and 15.5% less wind generation to achieve the same RPS target. The CAISO calculated an RPS annual cost reduction of $73 million and $44 million, respectively.

ii. Emission cost: CAISO calculated a $1 million cost increase for each case.

(d) Renewable integration benefits: The main benefit from this category is reduction in the cost of excess renewable generation. Without pumped storage, CAISO's calculated that

[38] 2016-2017 Board Approved ISO Transmission Plan, March 17, 2017, pages 337-338, http://www.caiso.com/Documents/Board-Approved_2016-2017TransmissionPlan.pdf

[39] https://www.ISO.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf. Section 10.8 and the soft offer cap basis was established as the sum of mid-cost results for insurance, ad valorem, and fixed operation and maintenance costs included in the CEC's draft staff report *Estimated Cost of New Renewable and Fossil Generation in California*: available at: http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SD.pdf. The levelized fixed cost target presented in DMM's analysis of net market revenues for new gas-fired generation in Chapter 1 is based on the same report, but includes financing and taxes.

meeting the 50% RPS goal in 2026 would result in the need to curtail 4,615 GWh of renewable energy in the high solar generation case and 3,515 GWh in the high wind generation case. With 500 MW of pumped storage in Southern California, the curtailment would be reduced to 3,721 GWh and 2,970 GWh, respectively. The net reduction in renewable curtailment would be 894 GWh and 545 GWh respectively. CAISO used a curtailment price of -$15/MWh for the first 200 GWh of curtailment and -$25/MWh for the next 12,400 GWh of curtailment. The addition of LEAPS reduced the curtailment cost to ratepayers by $20.4 million and $11.6 million, respectively. Note that LEAPS can store approximately 2,400 GWh a year of renewable curtailment protection. The economics of additional savings are reflected in the production cost calculation. The fifth TEAM benefit category "Reliability and Avoided Cost Benefit of other Projects" was not studied by CAISO.

The following tables summarize the benefits quantified for the other three CAISO sensitivity cases that were studied for the 2026 year.

Table 4. Quantified TEAM Benefits for CAISO Sensitivity #1 – Updated Default Scenario

Sensitivity #1 - Summary of the CAISO analysis of the Updated Default Scenario (2026 Base case)			
Benefit Categories per TEAM	**Net Cost Reduction / Benefits ($M)**	**Solar Case**	**Wind Case**
California Production Cost Benefits	Net reduction in Energy Costs	$48.0	$40.0
	Net Reduction in Load Followings, Regulation and Spin Costs, and Energy Market Revenue for LEAPS	$52.3	$52.8
Capacity Benefits	LCR benefits	$37.8	$38.0
Public Policy Benefits	Reduction in RPS costs	$40.0	$29.0
	Reduction in Emission Costs	-$1.0	$0.0
Renewable Integration Benefits	Over-generation cost reduction	$10.7	$7.3
Reliability and Avoided Cost Benefit of other Projects	Interconnection Costs	not studied	not studied

Sensitivity #1 - Summary of the CAISO analysis of the Updated Default Scenario (2026 Base case)			
Benefit Categories per TEAM	**Net Cost Reduction / Benefits ($M)**	**Solar Case**	**Wind Case**
	Avoided large transmission investments	not studied	not studied
	Reliability benefits / Grid Resiliency	not studied	not studied
Total Benefits		**$187.8**	**$167.0**
Annual Revenue Requirements		**$177.1**	**$177.1**
One Year Benefit to Cost Ratio (BCR)		**1.06**	**0.94**

Table 5. Quantified TEAM Benefits for ISO Sensitivity #3 – Updated Default Scenario with 2015 IEPR Mid-AAEE

Sensitivity #3 - Summary of the CAISO analysis of the Updated Default Scenario with 2015 IEPR Mid -AAEE Sensitivity (2026 Base case)			
Benefit Categories per TEAM	**Net Cost Reduction / Benefits ($M)**	**Solar Case**	**Wind Case**
California Production Cost Benefits	Net reduction in Energy Costs	$42.0	$45.0
	Net Reduction in Load Followings, Regulation and Spin Costs, and Energy Market Revenue for LEAPS	$54.2	$52.7
Capacity Benefits	LCR benefits	$38.0	$38.0
Public Policy Benefits	Reduction in RPS costs	$44.0	$26.0
	Reduction in Emission Costs	-$2.0	-$2.0
Renewable Integration Benefits	Over-generation cost reduction	$11.9	$8.3
Reliability and Avoided Cost Benefit of other Projects	Interconnection Costs	not studied	not studied
	Avoided large transmission investments	not studied	not studied
	Reliability benefits / Grid Resiliency	not studied	not studied
Total Benefits		**$188.0**	**$168.0**
Annual Revenue Requirements		**$177.1**	**$177.1**
One Year Benefit to Cost Ratio (BCR)		**1.06**	**0.95**

Table 6. Quantified TEAM Benefits for ISO Sensitivity #4 – Updated Default Scenario with 4-tier Curtailment Prices

Sensitivity #4 - Summary of the CAISO analysis of the Updated Default Scenario with 4-tier Curtailments Prices (2026 Base case)			
Benefit Categories per TEAM	**Net Cost Reduction / Benefits ($M)**	**Solar Case**	**Wind Case**
	Net reduction in Energy Costs	$36.0	$43.0

Sensitivity #4 - Summary of the CAISO analysis of the Updated Default Scenario with 4-tier Curtailments Prices (2026 Base case)			
Benefit Categories per TEAM	**Net Cost Reduction / Benefits ($M)**	**Solar Case**	**Wind Case**
California Production Cost Benefits	Net Reduction in Load Followings, Regulation and Spin Costs, and Energy Market Revenue for LEAPS	$67.4	$63.0
Capacity Benefits	LCR benefits	$38.0	$38.0
Public Policy Benefits	Reduction in RPS costs	$33.0	$25.0
	Reduction in Emission Costs	$0.0	$0.0
Renewable Integration Benefits	Over-generation cost reduction	$8.6	$6.0
Reliability and Avoided Cost Benefit of other Projects	Interconnection Costs	not studied	not studied
	Avoided large transmission investments	not studied	not studied
	Reliability benefits / Grid Resiliency	not studied	not studied
Total Benefits		**$183.0**	**$175.0**
Annual Revenue Requirements		**$177.1**	**$177.1**
One Year Benefit to Cost Ratio (BCR)		**1.03**	**0.99**

VI. EXPANDED ANALYSIS

Q. How does your TEAM analysis expand on the ISO's analysis?

A. My analysis augments CAISO's analysis in five areas:

1. I used CAISO Sensitivity #2 results for benefits categories 1 through 4 and I calculated benefits category #5 (reliability benefits and avoided cost of other projects). The combined results are referred to as the "2026 base case."
2. I determined benefits for 2030 for all five categories. This is referred to as the "2030 base case."
3. I used the 2026 base case and 2030 base case results to calculate the benefits over the life cycle of the LEAPS project.
4. I calculated the base net present value benefits to cost ratio which is equal to the sum of the NPV of all benefit categories divided by the present value of LEAPS' total

revenue requirement ("BPV_BCR") for the life cycle of the project. The BPV_BCR is based on the specific input assumptions used by ISO in its Sensitivity #2 study.

5. I utilized the "uncertainty analysis" method from TEAM to calculate the net present value of expected benefits over the life cycle of LEAPS for 20 sensitivity cases that represent unique combinations of various input variables, and used to calculate the present value expected benefit to cost ratio or EPV BCR for the project.

Table 7 below summarizes the five benefit categories that I used to perform my analysis.

Table 7. TEAM Benefit Categories Quantified for LEAPS

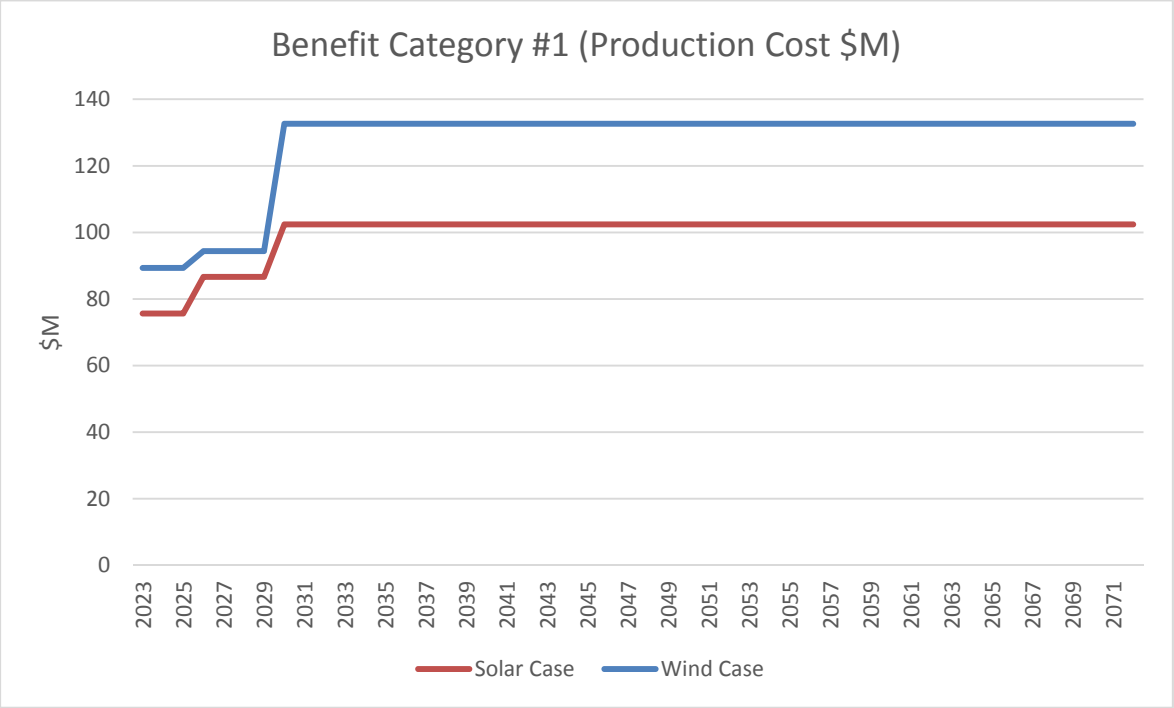
Benefit Categories per TEAM	Operational Use	Value Metrics	Methodology used to Calculate Benefits
California Production Cost Benefits	**Production Cost Savings**	LEAPS is used to charge during low-cost energy hours or hours with high renewable energy dispatch and store that energy so that it may be used or sold at a later time when it is more valuable. Its presence in the supply stack has potential to lower overall cost of energy to consumers.	ISO PLEXOS software and data & PUC RESOLVE software and assumptions.
	Ancillary Services	LEAPS has the ability to ramp up and down to maintain a supply and demand balance. LEAPS can provide regulation up / regulation down to comply with Reliability Standards and ensure second by second balance of supply and demand. LEAPS can provide on-line reserve capacity to comply with Reliability Standards.	
Capacity Benefits	**Local Transmission (LCR) Savings**	Avoided cost of purchasing existing capacity to meet LCR or deferral of cost in later years to build a new combustion turbine in the local area.	CAISO assumptions of LCR capacity benefit, $6.31/Kw-month.
Public Policy Benefits	**Reduced Cost of Renewables (RPS)**	RPS capacity reduction (reduced overbuild of solar or wind) to meet 50% RPS with LEAPS.	ISO study and data / PUC RESOLVE software and assumptions.
	Emission Cost Savings	LEAPS is a hydro pump storage and is able to reduce reliance of gas-fired energy, thus reducing emissions.	ISO PLEXOS software and data & PUC RESOLVE software and assumptions.
Renewable Integration Benefits	**overgeneration cost**	reduce the amount of renewable curtailments	ISO PLEXOS software and data PUC RESOLVE software and assumptions (overgeneration Pricing was based on historical avoided energy cost to load)
Reliability and Avoided cost Benefit for other Projects	**Transmission Interconnection Cost**	LEAPS reduces the nameplate capacity of renewables needed to achieve 50% state goals, therefore, reducing transmission interconnection cost associated with lowering capacity procurement.	PUC assumptions of transmission interconnection cost of $22/kW-yr.
	Avoided Large Transmission Investment	To meet the State's 50% RPS goals and 42MMt or 30MMt emissions targets under a high wind scenario, new transmission line investments are needed.	CAISO assumptions of new transmission cost of $12 $/MWH
	Grid Resiliency (Electric Reliability Services): Frequency Response and Inertia, Flexibility, Black Start, System Reliability	LEAPS provides a large and quick response to the depleted grid from essential reliability elements such as rotating mass near the load center, immediate response in the event of power outage lasting seconds to 12 hours.	this benefits is not included in the analysis since we consider voltage support is part of the electric reliability and is part of #2 benefit. However, CES/SCE separate Voltage from Electric Service reliability benefits and estimate the voltage benefits at $40/KW-YR. Table 11, page 64.

Q. What assumptions did you use to calculate LEAPS benefit category #1?

A. The base case for my expanded TEAM analysis was based on the ISO model and results for 2026, Sensitivity #2. This base case includes all CAISO assumptions for the Updated Default Scenario with non-dispatchable CHP. The only changes for 2030 base case was to update the load

forecast for the CAISO areas and the WECC. I then performed a chronological production cost analysis using the PLEXOS software and calculated the production cost savings and LEAPS' net market revenues from energy, load following, regulation and spin before and after LEAPS for 2030. **Figure 1** summarizes the production cost benefits to California ratepayers over the life of the project for the high solar penetration and high wind penetration sensitivities:

Figure 1. Production Cost Benefits to California Ratepayers due to LEAPS



Q. What assumptions did you use to calculate LEAPS benefit category #2 – Capacity Benefits?

A. LEAPS is located in the San Diego and Los Angeles load areas. For my analysis, I matched CAISO assumptions and considered LEAPS to be within the San Diego LCR area. I assumed that the capacity benefit in 2030 remained the same as 2026 base case, which is a $38 million annual benefit for both the high solar and high wind penetration sensitivities over the life of the project.

Q. Describe the local capacity requirement?

A. The CAISO's "Local Capacity Requirement" or LCR is defined as the amount of generation resource capacity that is needed within a defined area to reliably serve the load located within that area to protect against contingencies. A benefit of the LEAPS project is that it can provide local and system resource reserve capacity needed to satisfy the LCR for the San Diego-Imperial Valley area as well as be used for system wide capacity requirements.

Q. Did the CAISO agree that LEAPS qualifies to fulfill local capacity requirements?

A. Yes, CAISO's 2016-2017 Final Transmission Plan indicated that LEAPS would be inside the San Diego load pocket and qualifies as a local capacity resource.[40] In addition, the Net Qualifying Capacity ("NQC") that counts toward local capacity is 100% versus out-of-state wind's NQC of 17% or large solar's NQC of 47%. So, 100% of LEAPS can be counted towards LCR or system capacity needs, or Resource Adequacy.[41]

Q. What contingency worries the CAISO in the San Diego-Imperial Valley area?

A. The most critical contingency resulting in thermal loading concerns for the overall San Diego-Imperial Valley area is the G-1/N-1 (Category B) overlapping outage that involves the loss of the 593 MW Termoelectrica De Mexicali ("TDM") combined cycled power plant, system readjustment, followed by the loss of the Imperial Valley – North Gila 500 kV line (Category C), or vice versa. This overlapping contingency could thermally overload the Imperial Valley – El Centro 230 kV line (the "S" line). This contingency establishes a total local capacity need of 4,643 MW (includes 71 MW of deficiency) in 2022 for reliable load serving capability within the overall San Diego – Imperial Valley area.

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[40] http://www.caiso.com/Documents/Board-Approved_2016-2017TransmissionPlan.pdf, Section 6.5.6.

[41] *Id. at* Table 6.5-5 of CAISO 2016-2017 Transmission Plan.

The overload of the S line planning contingency is in the CAISO powerflow base case that I used as the starting point for my analysis. The power flow studies I performed show that adding the LEAPS project resolves the S line overload when the TDM plant and the Imperial Valley-North Gila 500 kV line are both out of service. This shows that the LEAPS project significantly benefits the system and resolves violations under the most critical conditions.

Q. How can LEAPS reduce the LCR for the San Diego-Imperial Valley area?

A. To decrease LCR for a specific area, either new major transmission projects need to be added, or a new resource needs to be placed in strategic spots to reliably serve the load under a critical outage. In this case, LEAPS project serves as both, (1) a new major transmission project that will benefit both the SDG&E and SCE systems, and (2) a new 500 MW generating facility that is within the San Diego-Imperial Valley LCR that can replace the existing conventional generation.

I ran power flow analyses to determine LEAPS' benefits for satisfying LCR needs. Per my analysis, adding LEAPS benefits both the SCE and SDG&E areas. Adding LEAPS decreases imports from the Imperial Valley substation by 377 MW compared to a no LEAPS case, and decreases imports from SCE by approximately 134 MW compared to a no LEAPS case. This means that SCE and SDG&E will be able to reduce their reliance on high cost local gas-fired generation to satisfy its LCR. Exhibit NHC - C provides further details regarding the assumptions, study approach and results of my power flow analysis.

Q. What do you conclude about the LCR benefits of LEAPS?

A. My assessment shows that the proposed LEAPS project will allow the San Diego-Imperial Valley area to serve their customers reliably during periods of unusually high energy demand, unexpected outages and abnormal conditions. LEAPS also provide flexibility in operating

California's transmission grid by adding additional import capability to San Diego County from the north, which has limited connectivity to the rest of the CAISO grid. In summary, my analysis demonstrates that LEAPS provide consumer benefits as an LCR resource and transmission reliability project. The value of the LCR capacity benefit is $6.31 kW-month based on 500 MW generation, this results in an annual benefit of $38 million.[42] I kept the capacity benefits flat over the project life cycle.

Q. What assumptions did you use to calculate LEAPS benefit category #3 – Public Policy Benefit?

A. I calculated the public policy benefits as the cost savings from reduced solar or wind overbuild to meet the 50% RPS criteria. The cost savings is based on the CAISO Sensitivity #2 results summarized below:

	Overbuild Generation Before LEAPS		Overbuild Generation with LEAPS	
Summary of RPS MW Overbuild	**Solar Case (MW)**	**Wind Case (MW)**	**Solar Case (MW)**	**Wind Case (MW)**
Basecase: Sensitivity #2 - Summary of the ISO analysis of the Updated Default Scenario with Non - Dispatchable CHP (2026 Base case)	1619	1211	1296	1023

Summary of RPS MW Overbuild Reduction	**Solar case (MW)**	**Wind Case (MW)**
Basecase: Sensitivity #2 - Summary of the ISO analysis of the Updated Default Scenario with Non - Dispatchable CHP (2026 Base case)	323	188

[42] https://www.ISO.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf. Section 10.8 and the soft offer cap basis was established as the sum of mid-cost results for insurance, ad valorem, and fixed operation and maintenance costs included in the CEC's draft staff report *Estimated Cost of New Renewable and Fossil Generation in California*: available at: http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SD.pdf. The levelized fixed cost target presented in DMM's analysis of net market revenues for new gas-fired generation in Chapter 1 is based on the same report, but includes financing and taxes.

The CAISO calculated that 500 MW pump storage would reduce the renewable energy needs by a net of 323 MW and 188 MW under the high solar and wind sensitivities, respectively. This reduction in renewable generation while meeting the State energy RPS objectives would save California's ratepayers $73 million and $44 million under the high solar and wind penetration sensitivities, respectively for year 2026. This translate to $226/kW-year and $234/kW-year of annual revenue requirement for the high solar and wind sensitivity cases, respectively. RPS cost savings is directly attributed to the loads. As load increases, the RPS capacity needed to maintain 50% also increases.

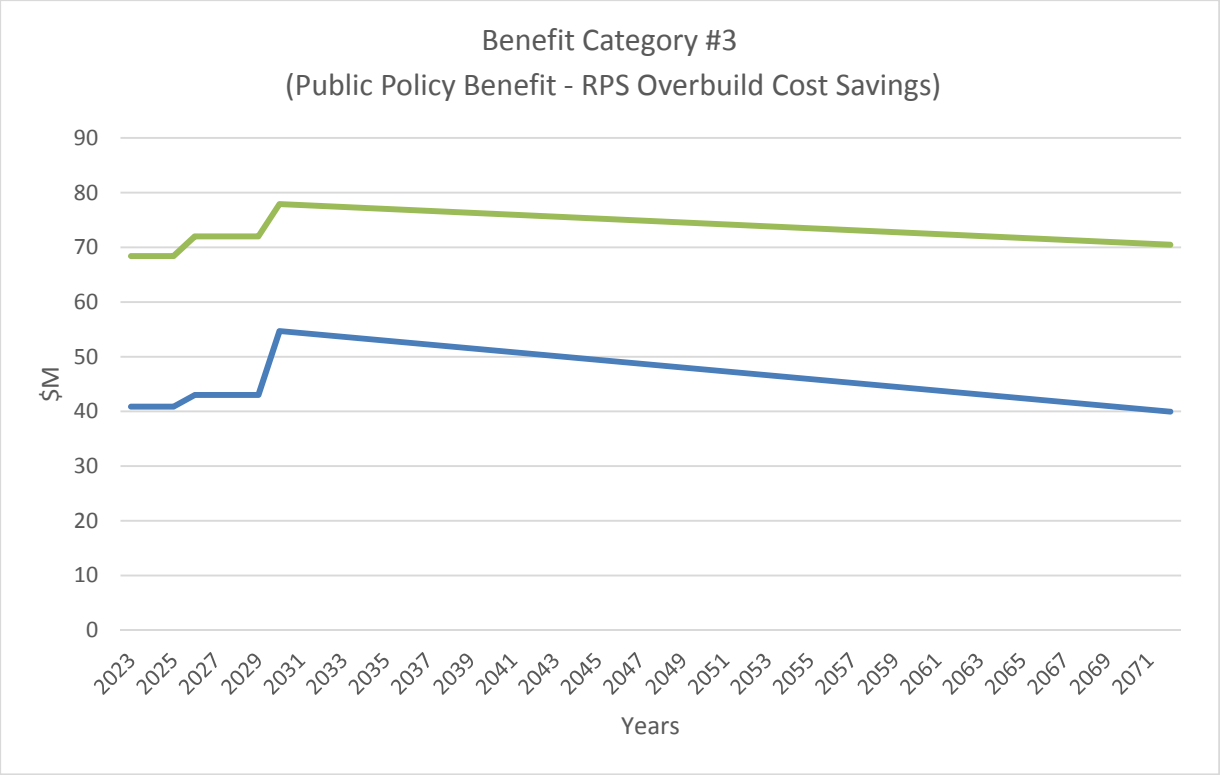
Table 8 shows the projected CAISO load in GWh for 2030. I estimated that 50% of the incremental RPS requirement from load increase in 2030 will come from solar and wind generation. I also used a 3% annual decrease in incremental renewable costs from the 2030 annual revenue requirement. Table 8 summarizes the projected load growth.

Table 8. Projected Loads for 2030

California Load for LEAPS PLEXOS Model			
Region	2026 Energy (GWh)	2030 Energy (GWh)	% Increase
PGE_Bay	52,535	54,992	4.7%
PGE_Valley	67,268	69,267	3.0%
SCE	120,825	124,049	2.7%
SDGE	24,691	25,609	3.7%
CAISO	**265,320**	**273,918**	3.2%
IID	4,709	5,009	6.4%
LADWP	31,717	32,801	3.4%
SMUD	19,639	20,464	4.2%
TID	2,975	3,084	3.7%

Figure 2 below summarizes the benefits realized from RPS overbuild cost savings with LEAPS for the life cycle of the project.

Figure 2. RPS Overbuild Cost Savings to California Ratepayers due to LEAPS



Q. Can you explain how LEAPS would provide TEAM benefit for category #4 – Renewable integration benefit?

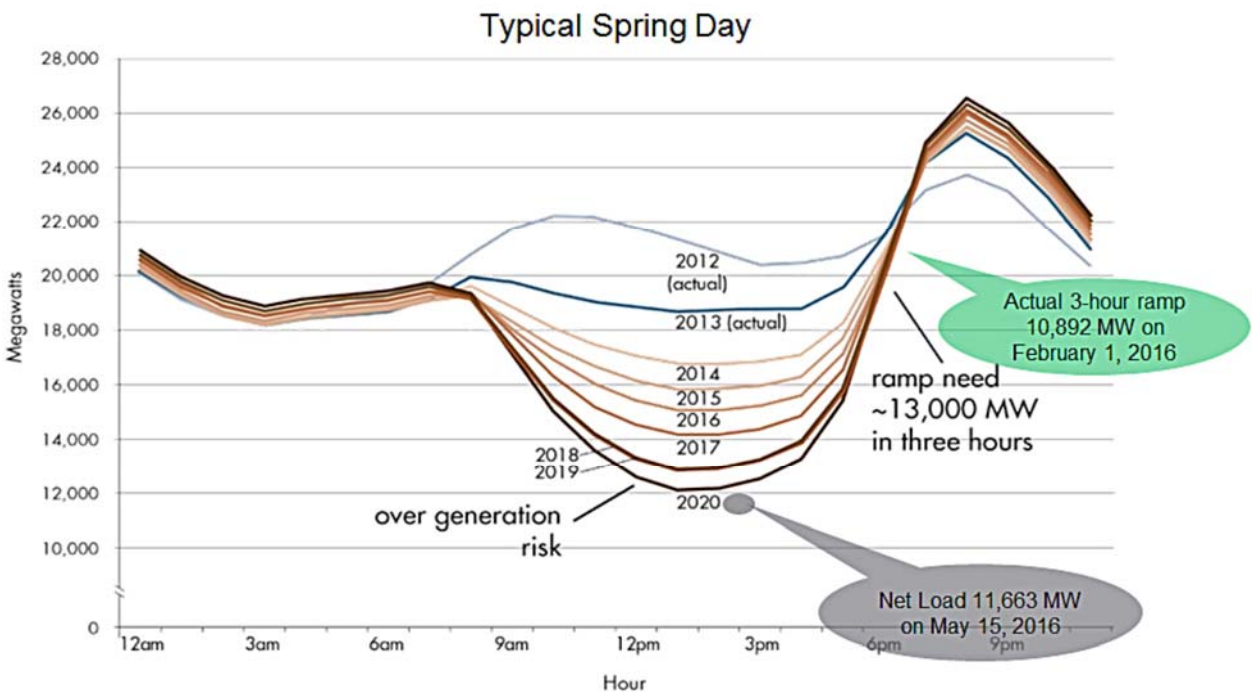
A. The main benefit from LEAPS in this category is its ability to reduce over-generation and thus the costs of renewable generation curtailments under these conditions.

Q. Please elaborate on the problem of over-generation.

A. This problem has existed for years and is increasing as the proportion of renewable energy increases in California. Over-generation is a condition that occurs when total supply exceeds total demand in the CAISO Balancing Authority Area. The CAISO has what is sometimes called a "Day 2" wholesale power market because generator owners offer to make their generating capacity available on one day, and then must deliver it the next day when it is settled at the real-time energy price. When—as is normally the case—the amount of generating capacity accepted for sale the first day differs from the amount of capacity the CAISO actually needs to serve load the next day,

it makes adjustments, which have consequences for the wholesale price of electricity in real time, as shown in **Figure 3**.

Figure 3. The Duck Chart



Net load shown in the chart is the difference between forecasted load and expected electricity production from variable generation resources. In certain times of the year, these curves produce a "belly" appearance in the mid-afternoon. Increasing demand in late afternoon requires generation to ramp up, that appears in the chart as an "arch" that resembles the neck of a duck—hence the industry moniker of "The Duck Chart".

The Duck Chart shows that over-generation conditions can occur in real-time when the quantity of supply needed to meet demand is less than the generating capacity that cleared in the Day Ahead Market. The excess day ahead cleared supply needs to be curtailed by CAISO to maintain reliable operations because currently there are extremely limited opportunities to store the extra electricity. CAISO Operating Procedures No. 2390 states "[t]his condition may affect

the reliable operation of the ISO Controlled Grid, Balancing Authority Area, and the WECC interconnected Bulk Electric System. Severe Over-generation may result in critically loaded transmission facilities, significant frequency deviations, high or low voltage conditions, and unacceptable system performance."[43] The price consequences for curtailments necessitated by the Duck Chart are further illustrated at Exhibit NHC-B, which provides several examples of how generators are paid for curtailing energy in such scenarios.

Increasing renewable energy penetration will make the challenges represented by the Duck Chart worse. In an analysis published in January 2014 funded by the State's utilities with participation by the CAISO, Energy and Environmental Economics ("E3") reported that the largest integration challenge for renewable energy is over-generation, which they expect to be pervasive at RPS levels above 33 percent.[44] E3's modeling of a 40 percent RPS scenario showed over 5,000 MW of over-generation, while the modeling of a 50 percent Large Solar Portfolio scenario—relying mostly on large, utility-scale solar photo-voltaic resources in keeping with current procurement trends—indicated over 20,000 MW of over-generation. Clearly, simply building more generation will not relieve these burgeoning difficulties.

The CAISO also performed detailed analysis for every day of the year from 2012 to 2020 to understand changing grid conditions. The analysis showed how real-time electricity net demand changes in response to renewable policy goals. Several conditions emerged that will require specific resource operational capabilities. The conditions include the following:

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[43] Operating Procedure 2390: http://www.caiso.com/Documents/2390.pdf

[44] Energy and Environmental Economics (E3), *Investigating a Higher Renewables Portfolio Standard in California*, pp. 25-33 , *available at*: https://www.ethree.com/wp-content/uploads/2017/01/E3_Final_RPS_Report_2014_01_06_ExecutiveSummary-1.pdf.

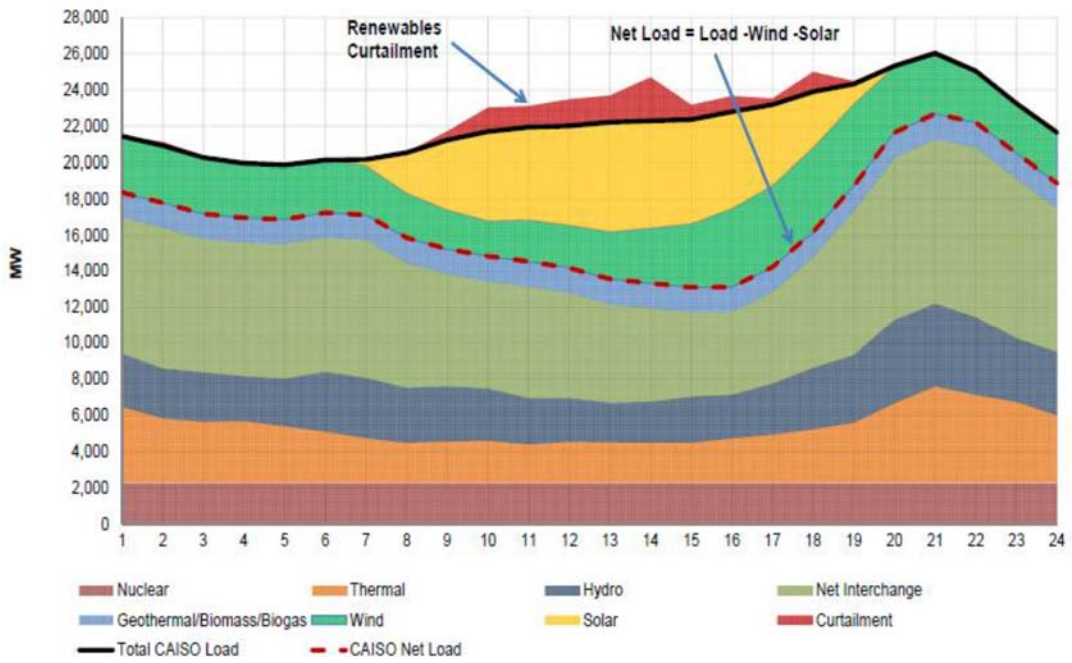
- Short, steep ramps – when the ISO must bring on or shut down generation resources to meet an increasing or decreasing electricity demand quickly, over a short period of time;
- Oversupply risk – when more electricity is supplied than is needed to satisfy real-time electricity requirements; and
- Decreased frequency response – when less resources are operating and available to automatically adjust electricity production to maintain grid reliability.

Maintaining reliability requires balancing supply and demand. The net load curves represent the variable portion that CAISO must meet in real time. To maintain reliability, the CAISO must continuously match the demand for electricity with supply on a second-by-second basis, which is known as frequency response. Historically, the CAISO directed conventional, controllable power plant units with automatic generation control capability to move up or down with the instantaneous or variable demand. With the growing penetration of renewable generation on the grid, there are higher levels of non-controllable, variable generation resources that lack frequency response capability.

Inadequate frequency response is not the only problem. Balancing Authority Areas must also balance supply with demand over the generation scheduling interval (historically an hour). Generation would be scheduled to meet anticipated changes in demand that is somewhat predictable. Demand typically ramps up during the morning hours and again in the early evening hours, for example. With dispatchable fossil generation, the transmission system operator is concerned only with load variability, which is accommodated through regulation service (the "Schedule 3" ancillary service in the transmission tariff). Renewable generation is variable and not controllable, which means the system operator must balance the system over the scheduling interval to account for changes to both load *and* generation. The net load curve shown for a sample

day in the CAISO region in Figure 4, below, best illustrates this variability. The net load is calculated daily by taking the forecasted load and subtracting the forecasted electricity production from variable generation resources (wind and solar). The daily net load curves capture one aspect of CAISO's forecasted variability. There will also be variability intra-hour and day-to-day that must be managed.

Figure 4. ISO Net Load Curve



The foregoing explanation and the charts at **Figure 3** and **Figure 4** illustrate the challenges the CAISO faces with integrating and managing renewable resources in real time. As I will explain, the LEAPS project is a solution that can help avoid oversupply conditions, instantly resolve real-time over-generation and mitigate cost risks associated with renewable energy curtailments which, as shown later, impact California ratepayers in a significant way.

Q. Is there a solution to this problem?

A. Yes. The current solution to this problem is to curtail renewable resources. But there are other options. Electric storage, flexible load, or regional coordination solutions could reduce the

cost impacts by enabling a larger portion of renewable energy output to be delivered to the grid without the adverse pricing consequences shown in the Duck Chart.[45]

Q. Can CAISO sell the over-generation to a neighboring balancing authority within WECC?

A. The State of California restricts PCC1 and PCC2 renewable energy from being exported as the renewable generator may lose its PCC1 or PCC2 renewable designation. Losing this designation will have a significant financial impact on these renewable generators, and therefore CAISO will be reluctant to sell over-generation energy resulting from excess renewable generation.

Q. How did you calculate the benefit of pumped storage from the LEAPS project to ease the over-generation problem?

A. I applied the CAISO 4-tiered renewable curtailment prices applied in its study as shown in the **Table 9** below to the curtailment reduction in each of the cases.[46]

Table 9. Curtailment Price Assumptions

	Tier 1	Tier 2	Tier 3	Tier 4
Curtailment Price ($/MWh)	-15	-25	-50	-150
Max Curtailment (GWh)	200	1,300	500	All the rest

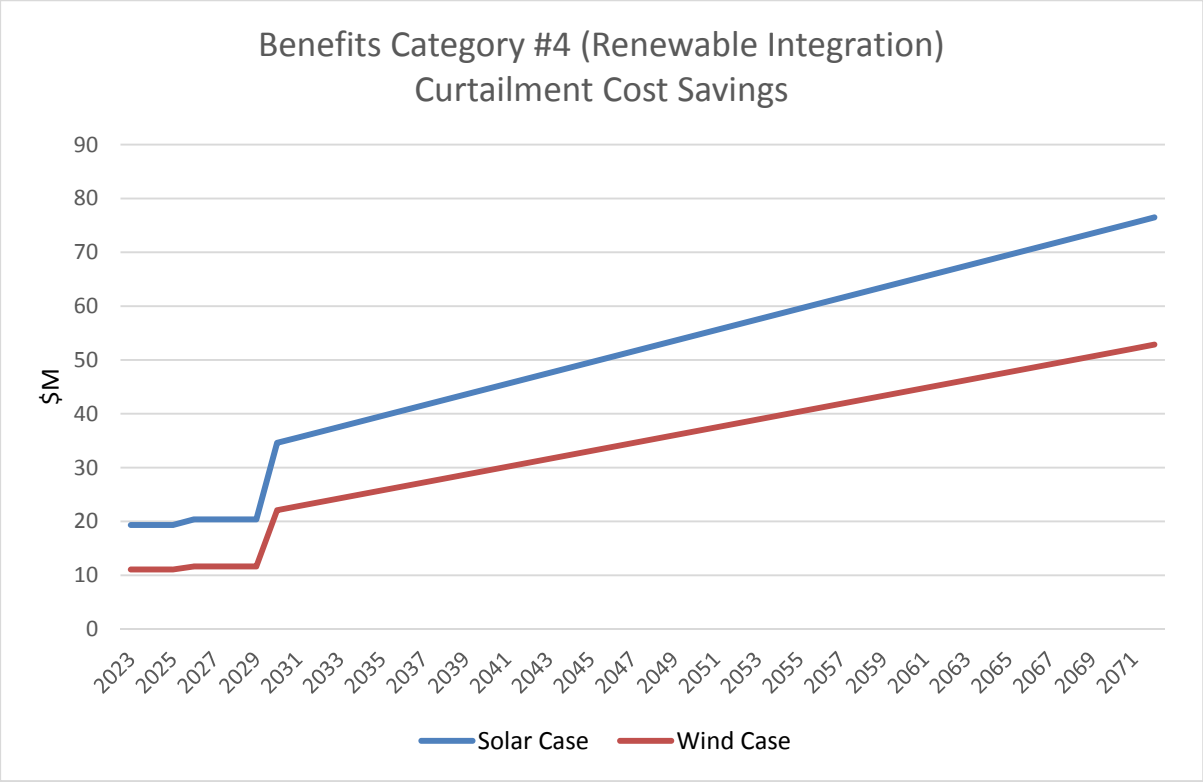
Q. Can you summarize LEAPS' renewable integration benefits?

[45] California ISO, Using Renewables to Operate Low Carbon Grid: Demonstration of Advanced Reliability Services from a Utility-Scale Solar PV Plant (2016), available at: https://www.caiso.com/Documents/UsingRenewablesToOperateLow-CarbonGrid.pdf .

[46] http://www.caiso.com/Documents/SupplementalSensitivityAnalysis-BenefitsAnalysisofLargeEnergyStorage.pdf, at page 6.

A. **Figure 5** below summarizes the over-generation cost savings over the life cycle of the project. As expected, the benefits increase every year as clearing prices during solar hours will continue to decrease.

Figure 5. ***Curtailment Cost Savings to California Ratepayers due to LEAPS***



VII. RELIABILITY AND AVOIDED COST OF OTHER PROJECTS

Q. Can you explain TEAM benefit category #5?

A. Yes, for my analysis, I quantify three sub-categories for the reliability and avoided cost benefits as follows:

1. Reliability benefits due to increased flexible capacity, frequency response and inertia,
2. Avoided generation interconnection cost, and
3. Avoided cost of large transmission investments.

Q. What is flexible capacity?

A. Load following is the ability to match generation schedules to load over the course of the scheduling interval. In the days when utilities block-scheduled generators to serve load on an hourly basis, a generator might schedule 100 MW of capacity to meet an expected average load of 100 MW over the hour scheduling period. At the beginning of the hour the load might be 90 MW and at the end of the hour the load might be 110 MW. A generating resource is necessary to back down at the beginning of the hour to absorb the extra 10 MW being delivered, and then have the flexibility to make up the 10 MW shortfall at the end of the hour. Generators that can provide this "load following" have flexible ramping capability, which is essential to providing reliable service. Generation schedules in CAISO do not work exactly this way today, but the example illustrates the concept. CAISO considers load following to be a service that follows the deviations between five-minute and hourly block schedules of energy.

Q. What type of reliability services does LEAPS provide?

A. A bulk storage resource is known in the industry for its ability to quickly response to system needs outside the regulation band. The LEAPS project is designed to be highly flexible. The variable speed technology utilized by the project provide an incredible ability to move hundreds of stored MW's in minutes both in the generation and pump modes. The flexibility is a valuable reliability services and is in addition to the ancillary services such as regulation, spinning and load followings. The ability to start on a moment notice, provide voltage support, inertia and flexible capacity and energy with virtually no constraints beyond the 10 hrs. a day of full generation at full load (500 MW/hr) and 12 hour a day at full pumping of (600 MW/hr.). Furthermore, as I will discuss later in my testimony, LEAPS ability as a rotating machine can provide much needed flexibility/ramping and frequency response capabilities to the grid given the anticipated loss of more gas fired resources and Huntington beach synchronous condensers resources. As California

increases its renewable energy generation supply portfolio, the need for flexible generation will compound, because the system operator will need to account for the variability of both load and generation. As the amount of variable renewable generation increases, so will the need for "flexibility resources" that can accommodate the increased variability of generation as well as ever-changing real-time load. LEAPS will be able to help keep generation schedules and load in balance because it will have fast ramping capability is more than 100 MW per minute.

Q. Why can't CAISO use conventional generation provide this flexibility?

A. The first difficulty is the amount of conventional generation available to the CAISO is in decline, as I have mentioned. Beyond this, flexibility in a world with high renewable generation using conventional generation may be problematic for several reasons.

First, the grid needs fast moving resources to accommodate a large fluctuation of wind and solar variable output that is caused by a sudden wind gust (such as a thunderstorm) or cloud covering. Conventional generation does not have the ability to provide a fast response as their ramp rates are relatively lower than a hydro pump storage.

Second, considering that renewable generation will displace a portion of conventional generation best suited to address the grid's ramping requirements, a large number of the remaining units must be kept online and partially loaded or "spinning," which adds to wear-and-tear and degrades reliability.

Third, volatile ramping on conventional gas fired generation may have undesirable side effects, such as impacts to natural gas pipeline balances and increased emissions that conflict with restrictions in environmental operating certificates.

Fourth, market revenues may not adequately compensate the generators for their operating costs, forcing retirements or additional cost-based reliability must run ("RMR") contracts.[47]

Q. What is the solution?

A. To reliably operate in these conditions, the CAISO requires flexible resources defined by their operating capabilities. These characteristics include the ability to perform the following functions:

- sustain upward or downward ramp
- respond for a defined period of time
- change ramp directions quickly, store energy or modify use
- react quickly and meet expected operating levels
- start with short notice from a zero or low-electricity operating level
- start and stop multiple times per day, and
- accurately forecast operating capability.

The CAISO needs a resource mix that can react quickly to adjust electricity production to meet the sharp changes in electricity net demand. **Figure 3** (the "Duck Chart"), above, shows a net load curve for a typical spring day for years 2012 through 2020. This curve shows the megawatt amounts the CAISO must follow on the y axis over the different hours of the day shown on the x axis. Four distinct ramp periods emerge. This means that to ensure reliability under changing grid conditions, the CAISO needs resources with ramping flexibility and the ability to start and stop multiple times per day. To ensure supply and demand matches at all times, controllable resources will need the flexibility to change output levels, and start and stop as dictated by real-time grid

[47] It is worth noting at this point that RMR contract payments are recovered through CAISO transmission rates paid by all customers.

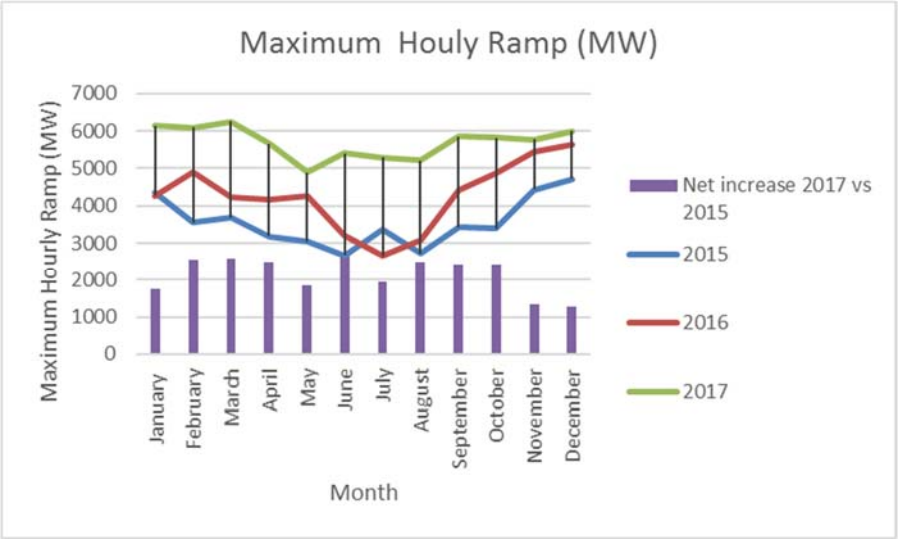
conditions. Grid ramping conditions will vary through the year. The net load curve or duck chart in **Figure 3** illustrates the steepening ramps expected during the spring. The duck chart shows the system requirement to supply an additional 13,000 MW, all within approximately three hours, to replace the electricity lost by solar power as the sun sets.

Q. How can LEAPS help?

A. LEAPS can provide the necessary quick-ramp load following for the CAISO grid. For instance, when the sun sets, California loses virtually all its solar energy in about 30 minutes.

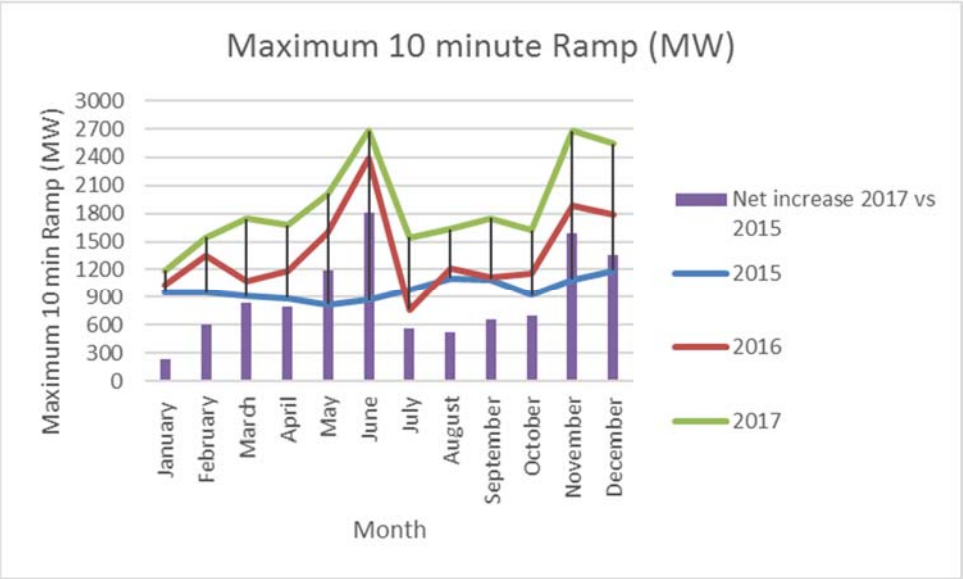
Figure **7** show the maximum hourly and 10-minute ramp requirement in megawatts by month for 2015, 2016 and 2017.[48] Both maximum and 10-minute ramp requirement steadily increase from 2015, 2016 and 2017. The net increase in ramping since 2015 is on the rise. LEAPS can be an effective, predictable and a large enough resource to deal with these multiple ramping requirements throughout the day.

Figure 6. ISO's Maximum Hourly Ramp Requirement by Month for 2015 - 2017



[48] http://www.ISO.com/Documents/MonthlyRenewablesPerformanceReport-Nov2017.html.

Figure 7. CAISO's Maximum 10-minute Ramp Requirement by Month for 2015 - 2017



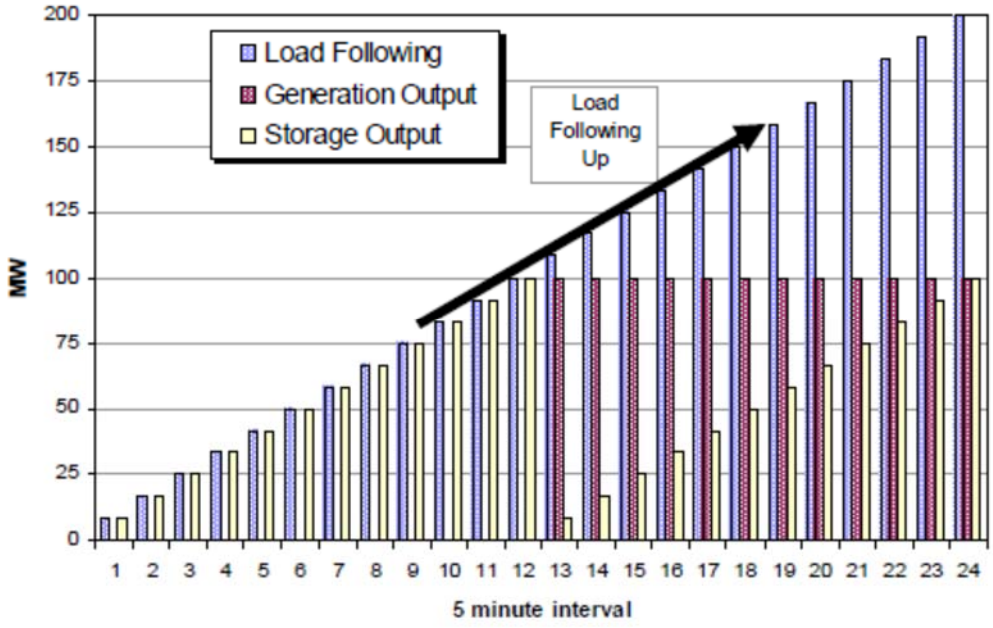
Q. Please explain.

A. The maximum hourly ramp in a given month is the amount of energy the CAISO would need from one hour to the next. Similarly, the maximum 10-minute ramp is the maximum amount of energy in a 10-minute period for a given month that CAISO needs to balance the system and maintain reliability. Energy for CAISO's steep ramping requirement means that it can only come from fast moving resources that are dispatchable. Solar and wind are intermittent resources and are non-dispatchable. Hydro and battery storage are considered the best, most responsive resources that can quickly be available. For instance, LEAPS can supply 500 MW in a few minutes, and turn around and shut down and act as a load in just four minutes. LEAPS can provide the flexibility and load following that the grid is increasingly needing.

Figure 8, below, illustrates this. The load following capacity is indicated by the blue bars labeled "Load Following." The rate of LEAPS' generation output increases as load increases (shown by the yellow bars labeled "Storage Output"). After the first hour of load following with LEAPS, a full 100-MW block of other ISO generation is dispatched (shown by the red bars) while

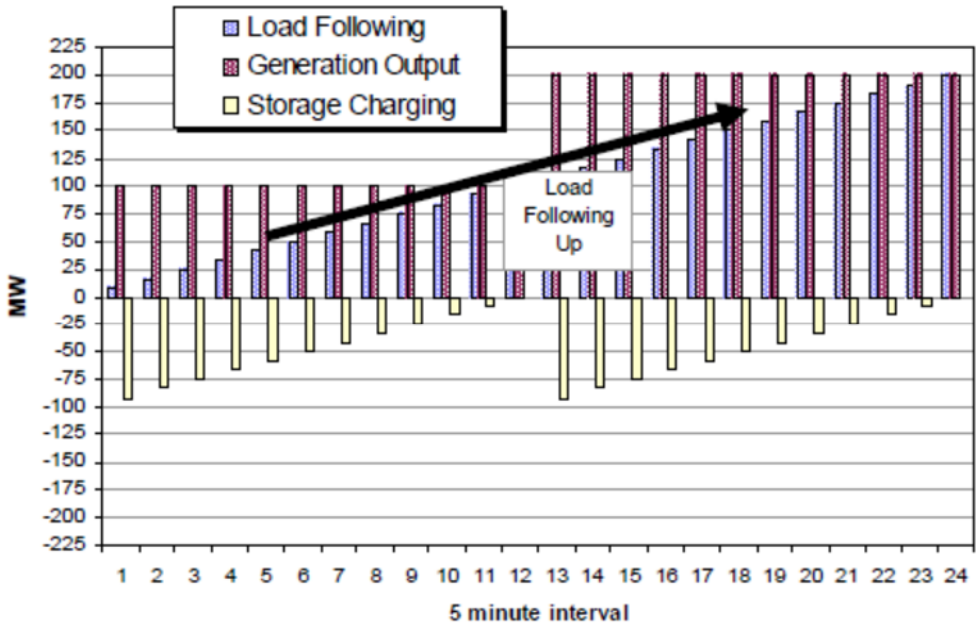
LEAPS generation is curtailed (at interval #13) when generation output such as wind (Red) becomes available. Throughout the second hour of load following, LEAPS' output can be increased every five minutes (as it was during the first hour) as load increases.

Figure 8. Illustration of How LEAPS Provides Load Following Up



LEAPS pumping can also be used to provide load following up by reducing the pumping load throughout an hour, commensurate with increasing load. Consider the illustration shown in , below. At the beginning of the first hour of load following, a 100-MW wind generator becomes available (see the red bars labeled "Generation Output"). At the same time, LEAPS begins pumping at a rate of 100 MW, which is equal to the wind generation. Every five minutes, the pumping load is reduced to the extent that load has increased (note the yellow bars labeled "Storage Charging"). The resulting load following up is shown by the blue bars. At the beginning of the second hour of load following, an additional 100 MW of wind generation becomes available, and LEAPS pumping commences again at 100 MW equal to the output of the second wind generator.

Figure 9. Illustration of How LEAPS Provides flexibility Up in Pump Mode



Q. How does LEAPS work when renewable generation decreases?

A. LEAPS provide load following down by decreasing its generation output and/or by increasing its pumping load as illustrated in **Figure 10** and , below. **Figure 10** shows how LEAPS generation can be used for load following down. LEAPS generation is dispatched from full output to very low (or no) output twice in a two-hour period. The example assumes that at the end of the previous hour (not shown), a 200 MW wind generator is reduced to 100 MW. Then LEAPS comes online (as shown by the yellow bars labeled "Storage Output"). Another 100 MW of wind generation is still online (shown by the red bars labeled "Generation Output"). The generation output is reduced every five minutes during the first hour as load drops. The resulting load following capacity is shown by the blue bars labeled "Load Following." At the beginning of the next hour, the 100 MW wind generator is reduced to zero and LEAPS begins generating again at 100 MW. Energy output from LEAPS decreases throughout the second hour as load decreases until output is zero at the end of the second hour.

Figure 10. Illustration of How LEAPS Provides Load Following Down

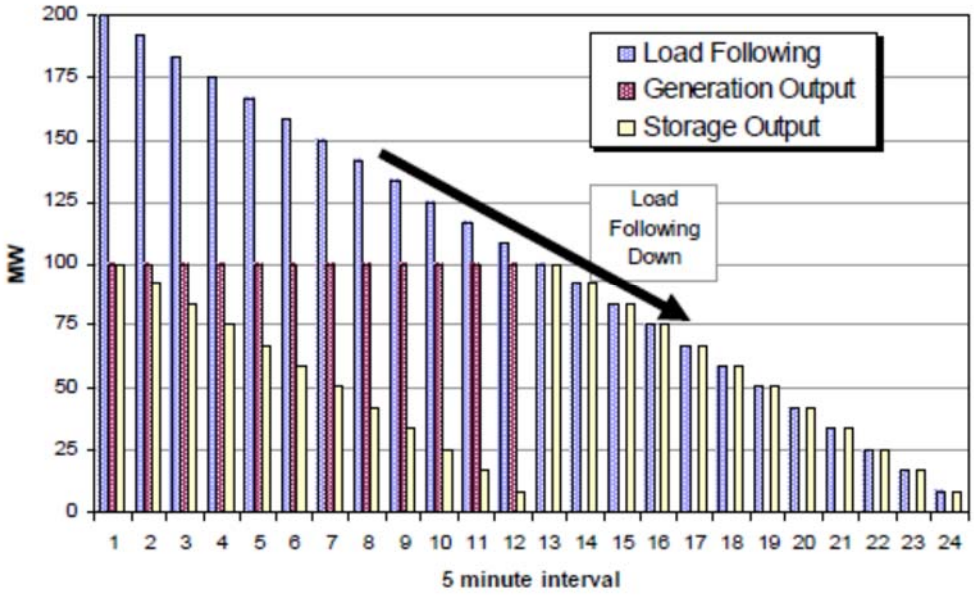
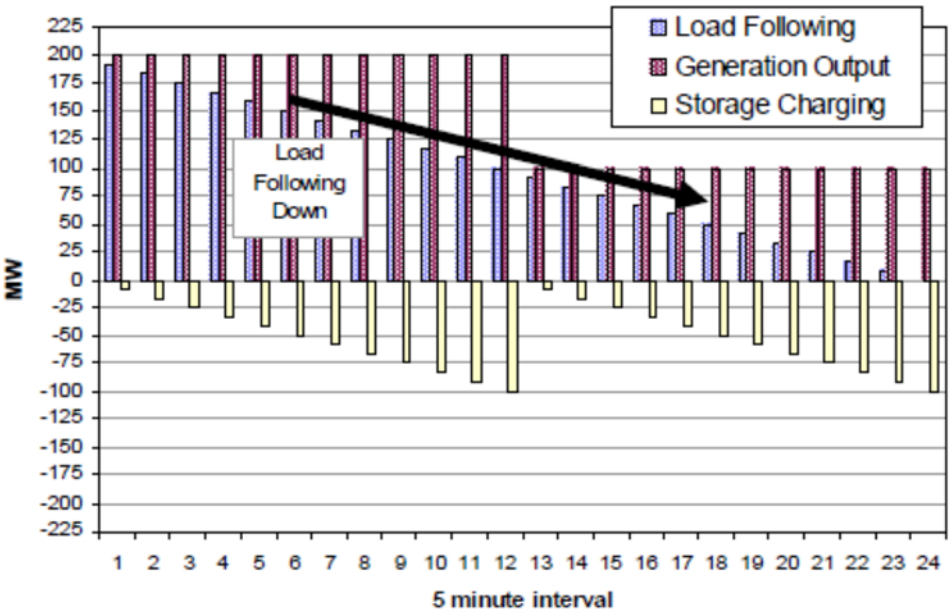


Figure 11 shows how LEAPS can be used to provide load following down while pumping. At the beginning of the hour, two 100 MW wind generators are on-line for a total of 200 MW (shown by the red bars labeled "Generation Output"). As load decreases, there is a commensurate increase of LEAPS pumping (shown by the yellow bars labeled "Storage Charging"). The resulting load following capacity is shown by the blue bars labeled "Load Following." At the beginning of the second hour, 100 MW of wind generation is not available, LEAPS begins pumping again with a low pump load. As load continues to diminish, LEAPS' pumping is increased until the beginning of the next hour (not shown) when LEAPS' pumping and wind generation both decrease to zero.

Figure 11. Illustration of How LEAPS Provides Load Following Down in Pump Mode



Q. What other critical reliability services does LEAPS provide?

A. LEAPS has the capability to provide the grid with more resiliency.

Q. What is grid resiliency?

A. Grid resiliency is a concept that encompasses traditional reliability through compliance the NERC rules concerning the operation of the bulk electric system in compliance with Section 215 of the Federal Power Act,[49] but also includes attributes that contribute to the robustness of the bulk electric system to respond to service disruptions, as the Commission recently explained an order on a proposed rule to address grid resiliency and pricing issues.[50] As FERC explained in its grid resiliency order, there is no common industry definition of "resilience," but commenters in the proceeding generally used the term to mean "[t]he ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to,

[49] 16 U.S.C. § 824o (2016).

[50] Order Terminating Rulemaking Proceeding, Initiating Proceeding, and Establishing Additional Procedures Proceeding reGrid Reliability and Resilience Pricing, 162 FERC ¶ 61,012 (2018).

and/or rapidly recover from such an event."[51] Among the questions FERC has posed for industry comment is to identify generation and transmission services that support grid resilience.[52]

I agree with FERC's definition. Resiliency has many attributes, but fundamentally it is obtained from a robust transmission system coupled with generating facilities with rotating mass or turbines (such as hydro, nuclear, coal, geothermal, biomass and gas-fired generation). One aspect is the ability of the grid to use generation and transmission assets to respond to any imbalance.

Q. Can you give an example?

A. Yes. A critical threat that lies at the root of most major blackouts is what happens in the first few seconds on the grid following an outage. These first few seconds is what determines whether the grid can absorb and recover from an outage, which lies at the core of FERC's proposed resiliency definition. For instance, one of the most common measures of reliability is system frequency which measures the extent to which supply and demand are in balance. To ensure reliability, system frequency must be managed in a very tight band around 60 hertz. When an unexpected event occurs that disrupts the supply-demand balance, such as a loss of a generator or transmission line, frequency is impacted. These events do not allow time for manual response and balance is maintained through generating facilities equipped with automatic generation control ("AGC") telecommunications and computer facilities that allow the generator to fluctuate in response to moment-to-moment frequency changes on the grid. Conventional and rotating generation resources include frequency-sensing equipment, or governors, that automatically adjust electricity output within seconds in response to frequency to correct out-of-balance conditions. If

[51] *Id*. at P 23. FERC required regional transmission organizations to file explanations with FERC regarding their approaches to ensuring grid resiliency, including whether they agree with FERC's definition.

[52] *Id*. at P 27(c).

frequency deviation is not corrected in a few seconds, there is a risk for the grid to become unstable which leads to a catastrophic blackout. Transmission providers are required to make frequency response service available to transmission customers under Schedule 2 of their open access transmission tariffs.

Q. Have generation trends in California impacted the frequency response capability of the transmission network?

A. Yes. In California, the availability of rotating machines equipped with AGC is diminishing and is being replaced mainly by wind and solar (both rooftop and utility scale).[53] Figure 12, below, shows the increase in renewable fueled generation. In addition, and in the vicinity of the LEAPS project, the 2,246 MW San Onofre nuclear plant with its massive 150-ton turbines has been taken out of service. Huntington Beach's 452-MVAR synchronous condensers is planned to be offline starting in 2018.[54] Encina will lose 950 MW of gas-fired generation, Morro Bay's 650 MW gas plant was shut down in early 2014, and the Diablo Canyon 2,200 MW nuclear facility is scheduled to retire by 2026. These developments all significantly and adversely affect the frequency response capability of the power grid.

Furthermore, section 2.3.4.2 of the ISO 2016-2017 transmission plan points out that the renewable generation dependability as a percentage of name plate under stress summer peak conditions varies between 100% for biomass, geothermal and biogas to 36 % for solar and 0% for wind.[55]

Q. Do transmission facilities contribute to resiliency?

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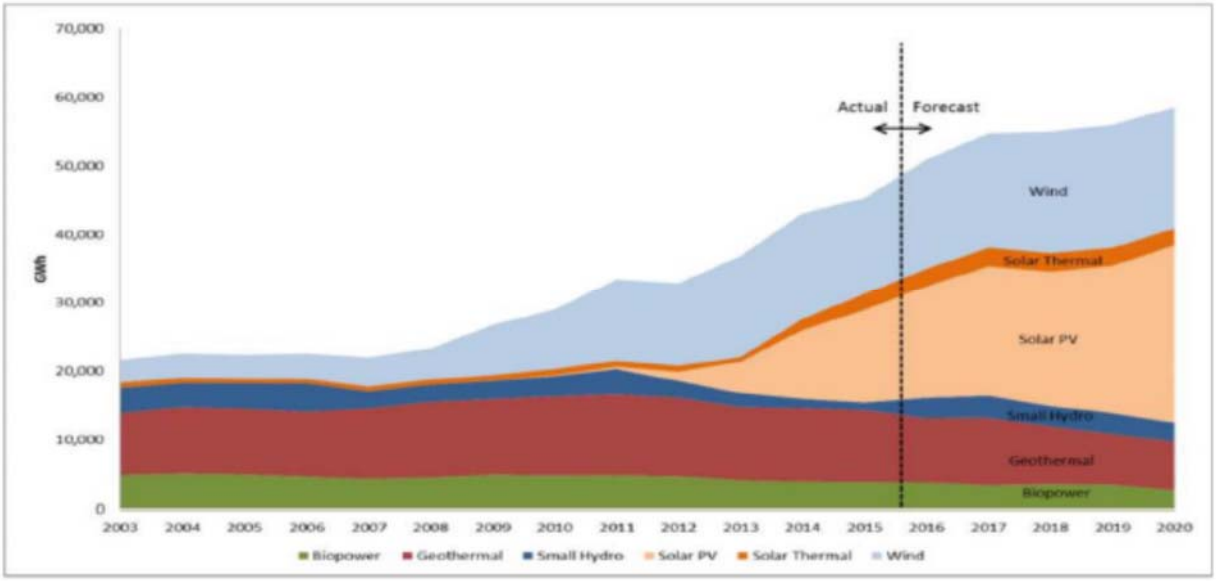
[53] CPUC Report to the Legislature in Compliance with Public Utilities Code Section 910, May 2015

[54] http://www.caiso.com/Documents/Board-Approved_2016-2017TransmissionPlan.pdf, Table 2.3-7, page 43.

[55] *Id.* at Table 2.3.6, page 41.

A. Yes, when the facilities are adequate to reach all economic supply. That is not always the case, however, which is why there are load pockets that require local generation to serve peak demand. For example, San Diego's load cannot be served exclusively from electric imports because there is not enough transmission capacity. Therefore, local generating capacity is required to serve peak demand.

Figure 12. Generation mix (Actual and Forecast)



Q. Has CAISO studied frequency response resiliency?

A. Yes. Part of the renewable integration analysis conducted by the CAISO uncovered concerns about frequency response capabilities due to the displacement of conventional generators on the system. The CAISO's 2020 33% renewable penetration studies show that in times of low load and high renewable generation, as much as 60% of the energy production would come from renewable generators that displace conventional generation, thereby depressing frequency

response capability.[56] Under these operating conditions, the grid may not be able to prevent frequency decline following the loss of a large conventional generator or transmission asset (*i.e.*, a NERC "N-1" reliability contingency). This situation would arise because renewable generators are not currently required to include AGC equipment and are operated at full output. Without this automated capability, the system becomes increasingly exposed to blackouts when generation or transmission outages occur.

Q. Have there been any other studies?

A. Yes. A recent study by the US Department of Energy's ("DOE") National Renewable Energy Laboratory found that about 65% of a typical rooftop solar energy customer's electricity demand is non-coincidental with the electricity generated from their own rooftop solar photovoltaic generating equipment.[57] Therefore, a 100% solar PV power supply portfolio would neither be capable of meeting peak demands nor be capable of supplying consumers connected to the grid with the electricity that they want, whenever they want it. That is clearly a problem.

Q. Has FERC done anything about this?

A. Yes. On January 16, 2014, FERC approved NERC Reliability Standard BAL-003-1, which placed a new frequency response requirement on BAAs (including the ISO). BAL-003-1 requires balancing authorities to demonstrate sufficient primary frequency response to disturbances in system frequency.[58] Primary frequency response is a service that provides an actual response to a

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[56] http://www.caiso.com/documents/FlexibleResourcesHelpRenewables_FastFacts.pdf and http://www.ISO.com/Documents/IssuePaper_FrequencyResponsePhase2.pdf.

[57] Lori Bird, *et al*., *Impact of Rate Design Alternatives on Residential Solar Customer Bills: Increased Fixed Charges, Minimum Bills and Demand-Based Rates,* https://www.nrel.gov/docs/fy15osti/64850.pdf.

[58] *Frequency Response and Frequency Bias Setting Reliability Standard*, Order No. 794, 146 FERC ¶ 61,024 (2014) ("Order 794") ("the purpose of this section is to present the reliability need underpinning frequency response service. The reliability need is to control frequency to stable levels to support a well-functioning grid. An interconnection needs to have a system frequency that is on average near the scheduled frequency value at 60 Hz. If frequency increases far above the scheduled value due to over-generation relative to demand it can lead to grid instability. If frequency decreases well below the scheduled value due to insufficient generation

frequency change when additional power is provided to the grid to arrest and stabilize frequency within 52 seconds by automatic, autonomous response either through control devices or system operator signals based on an algorithm that matches product specifications.

CAISO's analysis showed that it could at times be short of its required share of frequency response.[59] CAISO, therefore, filed tariff revisions to ensure interim compliance with BAL-003-1 for 2017 by procuring "transferred frequency response" and strengthening requirements for conventional resources.[60] Transferred frequency response is an annual contract to allow a transfer of frequency response performance between BAAs. FERC approved the filing September 16, 2016.[61] CAISO committed to evaluate whether a market mechanism should be designed to encourage frequency response capabilities of all participating resources, enable the diverse mix of resources to provide services, and ensures CAISO meets applicable reliability criteria.

Q. Are there other aspects of frequency response that are important?

A. Yes. Frequency response ride through and frequency inertia are two important concepts to understand, particularly when it comes to seeing how the LEAPS project can help the system.

Q. What is frequency response ride through?

A. This concept takes a bit of technical explanation. The frequency of the system will vary as load and generation change. Increasing the mechanical input power to a synchronous generator will not greatly affect the system frequency, but will produce more electric power from that unit. During a severe overload caused by tripping or failure of generators or transmission lines, the power system frequency will decline due to an imbalance of load versus generation. Loss of an

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relative to demand it can lead to grid instability. The under-frequency events introduce a high grid reliability risk since if an under-frequency event persists it could cause cascading black outs.").

[59] *Id*. at 4

[60] *Cal. Indep. Sys Operator Corp*., Tariff Revisions (Apr. 21, 2016).

[61] *Cal. Indep. Sys Operator Corp*., 156 FERC ¶ 61,182 (2016).

interconnection, while exporting power (relative to system total generation) will cause system frequency to rise. AGC is used to maintain scheduled frequency and interchange power flows. Control systems in power stations detect changes in the network-wide frequency and adjust mechanical power input to generators back to their target frequency. This counteraction usually takes a tens of seconds due to the large rotating masses involved. Temporary frequency changes are an unavoidable consequence of changing demand.

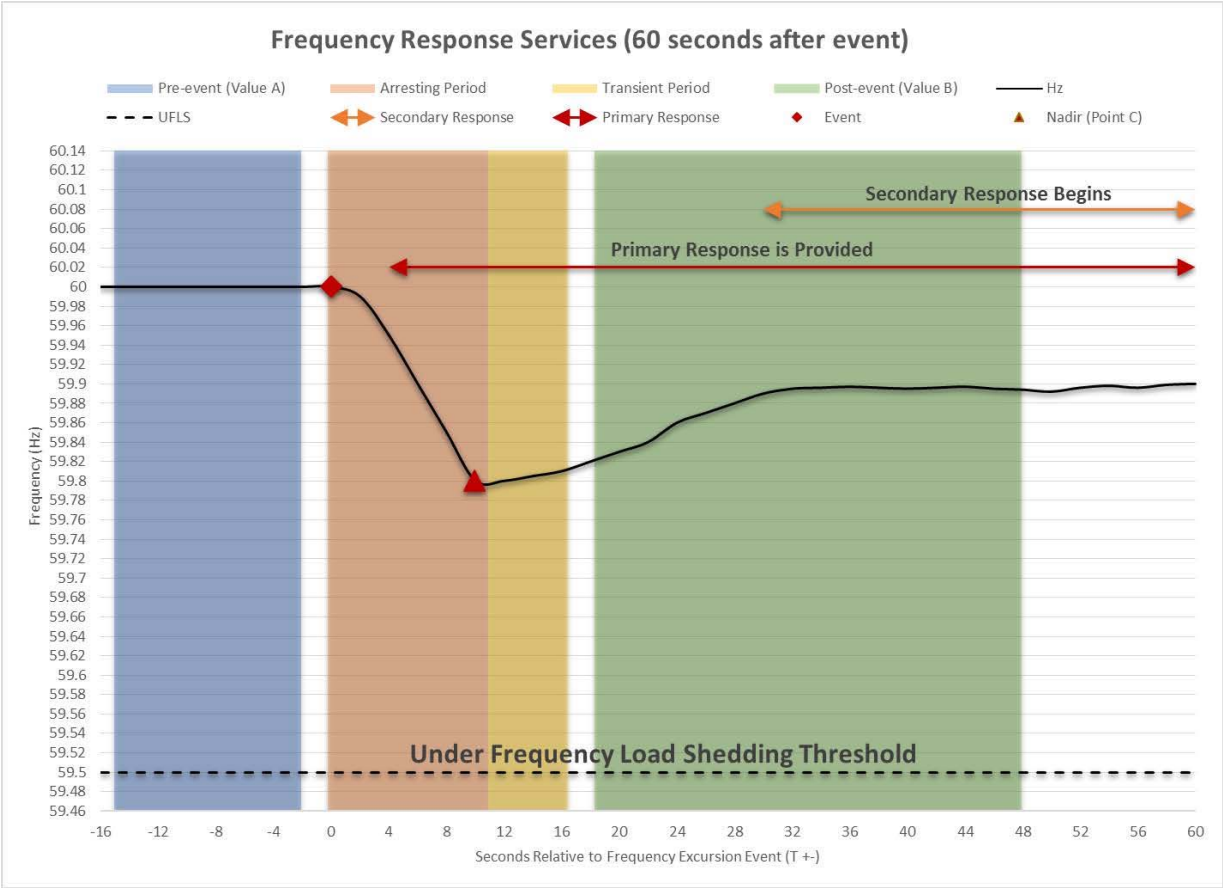
The operating frequency of the US grid is 60 Hz. Typically, a decreased frequency indicates that the load demand is greater than generation and vice versa. The frequency response of the system is a measure of its stability. For CAISO the frequency response required is around 258 MW for each 0.1 Hz (*i.e.*, capability to provide 258 MW in response to a drop in frequency by 0.1 Hz).[62] The resiliency of the system to frequency deviations improves with an increase in this value.

Frequency deviations occur during contingencies like loss of generation, loss of a transmission line followed by a remedial action scheme, etc. When such deviations occur, there are three types of actions taken to remediate the deviation: primary, secondary, and tertiary response.

Primary frequency response is the first line of defense against frequency deviations after an event, the frequency change is arrested and stabilized through automatic generator response, load response and other devices. The primary response starts within a few seconds of an event that leads to frequency deviation as shown in **Figure 13**, below. During these few seconds the frequency drops rapidly, and the drop is proportional to the amount of generation MW lost. This excursion will have to be arrested to prevent generators from tripping and to avoid load shedding.

[62] http://www.ISO.com/Documents/IssuePaper_FrequencyResponsePhase2.pdf, Table 1

Figure 13. Frequency Response Services after an Event[63]



Note that frequency during the "arresting period" needs to recover to 60 Hz in a couple of seconds. The longer the "arresting period," the less the grid is reliable. Arrest generators are protected by relays that read the frequency of the grid and isolate the generators from the grid when required. If the relays trip the generators for small up or down frequency deviations, they add to the instability in the system. So, NERC and WECC have mandated that a generator should operate within specific frequency limits even during a contingency event for a set period, this feature is called frequency ride through. These settings are given in **Table 10**, below. Beyond these limits, the generators are free to trip.

[63] *Id.*

Table 10. WECC Frequency Ride-Through Setting.

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

Q. What is generator inertia?

A. Inertial response of the system plays an important role in arresting the frequency excursion. The slope of the frequency excursion after the drop is inversely proportional to the inertia of the system. The inertial response with load damping provide stability to the system before frequency response can take place.

Hydro generators have massive prime movers which have a lot of inertia, especially 500 MW hydro generators as in the LEAPS project. Hence, when a contingency occurs, and the frequency varies, they do not speed up or slow down rapidly like other generators. They continue to provide stability to the system. This gives primary response time to act and stabilize the frequency. Even after the excursions, during the transient period hydro generators provide better stability than inverter based photovoltaic solar generation of similar size.

Q. How can LEAPS help frequency response?

A. To quantify the benefits that LEAPS can provide, I performed two frequency response studies and one inertia assessment for the SDG&E system using CAISO's transmission planning base case for 2022. I chose the 2022 base because that is when the project is expected to be in service.

Q. Please explain your first study.

A. The first study simulated frequency response for a generic 500 MW solar photovoltaic facility located at Lake Elsinore versus LEAPS upon the loss of the 500 kV Southwest Power Link transmission line, which serves as the major import path for SDG&E. Southwest Power Link is considered by ISO to be one of the greatest threat contingencies for the area.[64] The September 8, 2011 blackout in Southern California began when that transmission facility tripped off-line. The frequency response of each generator was monitored under both scenarios and the results are shown in **Table 11**.

Table 11. Frequency Response comparison for the loss of the 500 kV Southwest Power Link.

Frequency Response Comparison	Generic PV or LEAPS (Hz.)
Generic PV Case	-0.096
LEAPS Case	-0.022
% change in - ΔF	-77%

Q. What did your first study show?

A. My study shows that in the LEAPS case, the negative frequency deviation is less following the outage. The frequency deviates 77% less with LEAPS compared with 500 MW of Solar PV.

Q. Please describe your second study.

A. The second study compares the frequency response pre-and post-LEAPS upon the loss of the same 500 kV Southwest Power Link transmission line for three existing generators in the SDG&E area: (a) Solar PV connected to the Drew substation, (b) the 950 MW Encina combined

[64] For example, EDF Renewable Energy recently signed a long-term power sales contract with SCE to sell the output from a new 500 MW solar photovoltaic facility to be developed near Joshua Tree National Park.

cycle gas-fired generating facility, and (3) the 45 MW El Cajon gas turbines. **Table 12** summarizes the results pre-LEAPS and post-LEAPS simulations.[65]

Table 12. Summary of Frequency response Pre-LEAPS and Post-LEAPS.

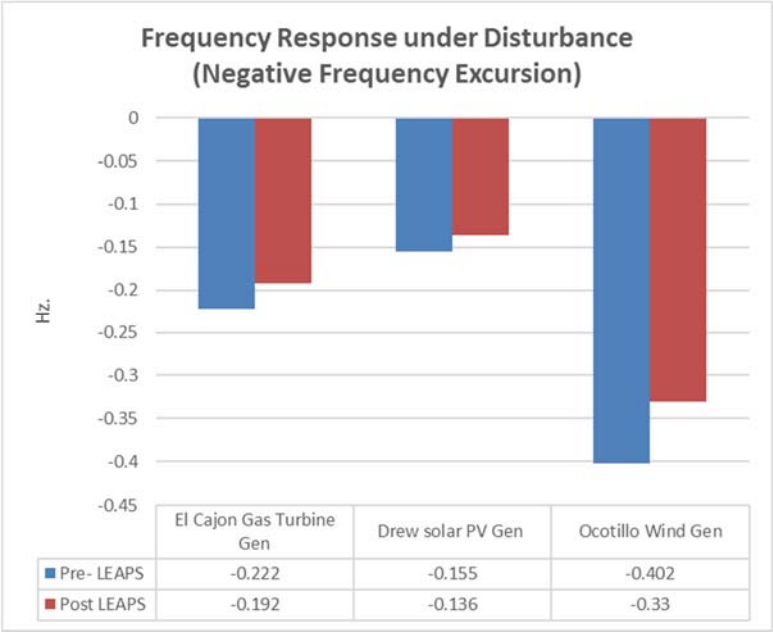
Plot Number-Generator	PRE - LEAPS				POST - LEAPS					
	Min Frequency Hz	-ΔF Hz	Max Frequency Hz	+ ΔF Hz	Min Frequency Hz	-ΔF Hz	% change in - ΔF	Max Frequency Hz	+ΔF Hz	% change in +ΔF
El Cajon Gas Turbine Gen	59.778	-0.222	60.140	0.140	59.808	-0.192	-14%	60.107	0.107	-24%
Drew solar PV Gen	59.845	-0.155	60.188	0.188	59.864	-0.136	-12%	60.183	0.183	-3%
Ocotillo Wind Gen	59.598	-0.402	60.133	0.133	59.670	-0.330	-18%	60.098	0.098	-26%

Q. What do you conclude from your second study?

A. The primary frequency response of different generators in the SDGE Area is monitored pre-LEAPS and post-LEAPS. When comparing the pre-LEAPS and post-LEAPS frequency values in **Table 12**, it is apparent that LEAPS reduces the magnitude of frequency excursions. The percentage change in frequency excursions (*i.e.*, ΔF presented in **Table 12** are negative indicating that the deviation in frequency is a lot less when LEAPS is present in the system). This is illustrated in **Figure 14**.

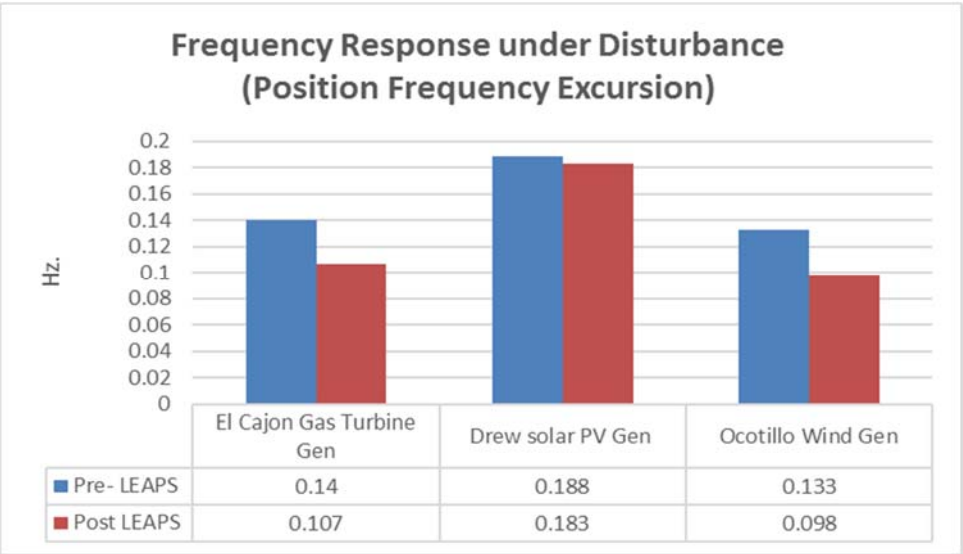
[65] Min Frequency is the lowest frequency, Max Frequency is the highest frequency. +ΔF represents change in frequency from the steady state value (60 Hz.). Small increase in frequency is consider more resilient grid. -ΔF represents decrease in frequency below the steady state value i.e. 60 Hz. Small decrease in frequency is considered as a more resilient grid scenario.

Figure 14. Graphical comparison of Negative Frequency Excursions Pre-LEAPS and Post-LEAPS



As shown in **Table 12** and **Figure 14**, with LEAPS, negative frequency deviation is 12% to 18% lower than without LEAPS. This means that under the outage, frequency "dips" less with LEAPS, as illustrated in **Figure 15**.

Figure 15. Graphical comparison of Positive Frequency Excursions Pre-LEAPS and Post-LEAPS



As shown in **Table 12** and **Figure 15**, with LEAPS, positive frequency deviation is 3% to 26% lower than without LEAPS. This means that under the outage, frequency "overshoot" is less with LEAPS. Also, note that with LEAPS the frequency settles at a value closer to the initial frequency and reaches the initial steady state quicker. In the plots shown in **Figure 16** through*, my study results show there are oscillations in the pre-LEAPS plots (Green) around the 13th second and the 18th second, which are not present in the plots obtained with LEAPS (Red).*

A general observation is that the oscillations in the plots are a lot less pronounced with LEAPS. **Figure 16**, below, also shows the response from the existing El Cajon Plant for a given loss of the same line under both a pre-LEAPS and a post-LEAPS scenario. The El Cajon gas turbine frequency dipped by 0.222 Hz in the pre-LEAPS case. In the post-LEAPS case, its frequency dipped by 0.192 Hz. El Cajon's frequency dipped 14% less with LEAPS in-service. **Figure 16** also shows that the frequency "over shoot" under the LEAPS scenario was 24% lower than without LEAPS. Finally, the gas turbine frequency stabilized in 8 seconds with LEAPS compared to without LEAPS, whereas the frequency for the gas turbine took 20 second to stabilize.

Figure 16. Frequency Response for an Existing Gas Turbine in San Diego Pre-LEAPS and Post-LEAPS

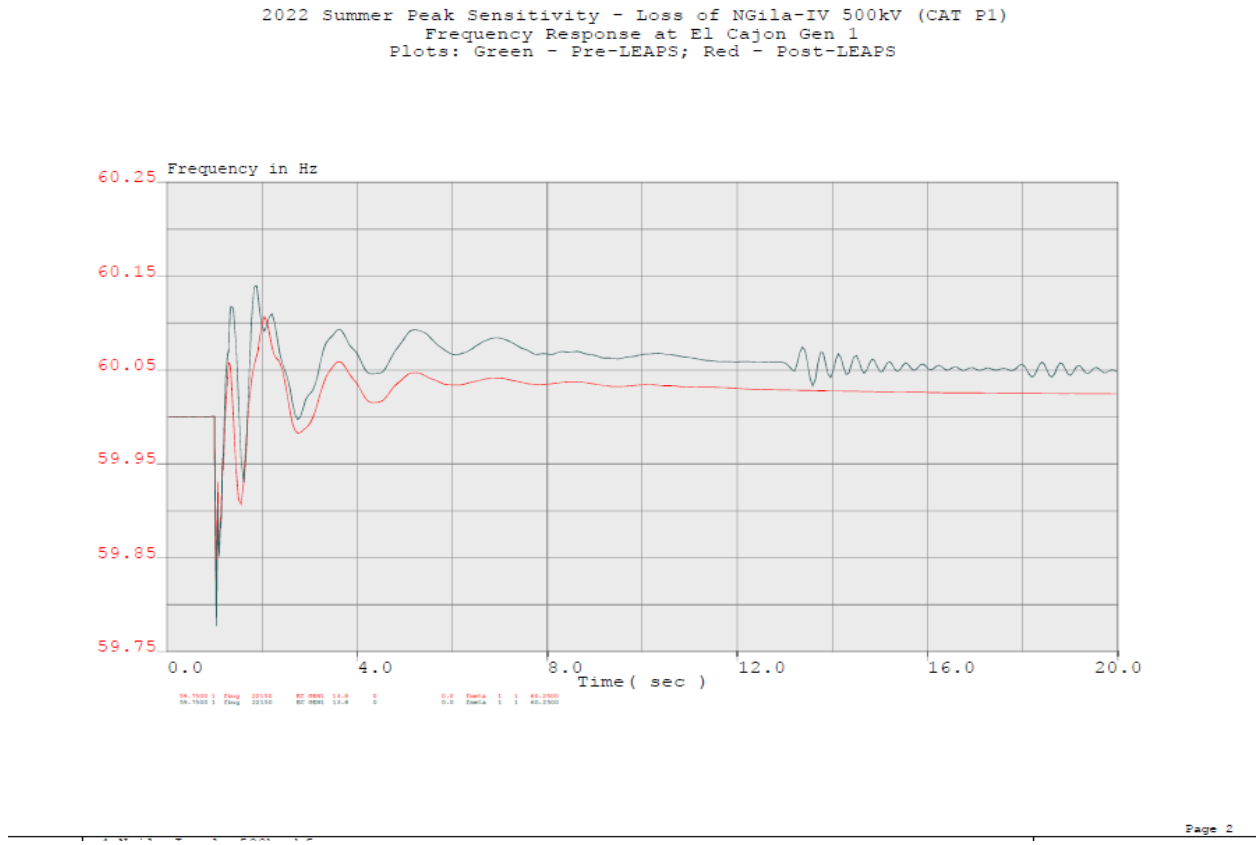


Figure 17, below, shows the response for the existing Drew PV plant pre-LEAPS and post-LEAPS for the loss of a single 500 kV line. The PV frequency dipped by 0.155 Hz in the pre-LEAPS case whereas it dipped by 0.136 Hz in the post-LEAPS case. This result is a 12% improvement with LEAPS. The frequency overshoot for Drew PV improved by 3% from +0.188 to +0.183 Hz and the stabilization time improved by approximately 4 seconds.

Figure 17. Frequency Response for an Existing Solar PV in San Diego Pre-LEAPS and Post-LEAPS

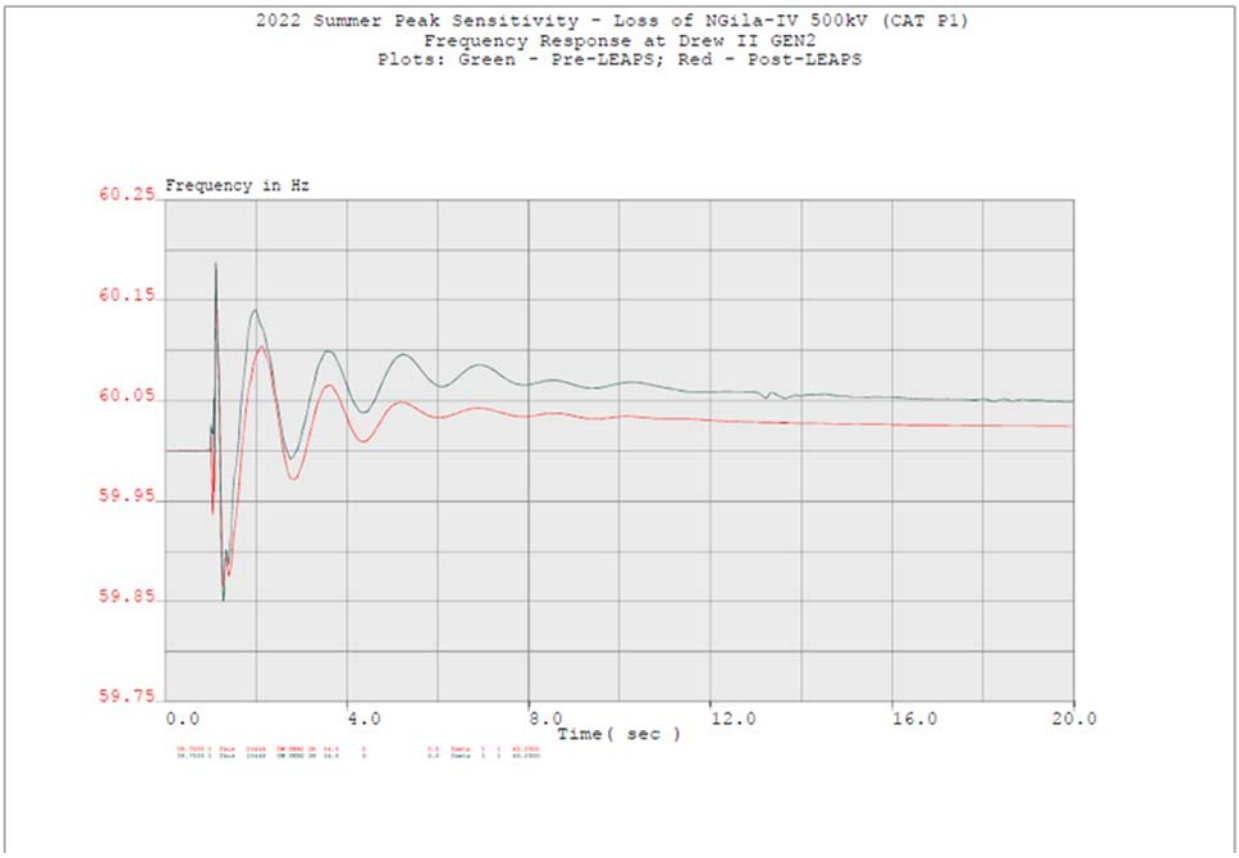
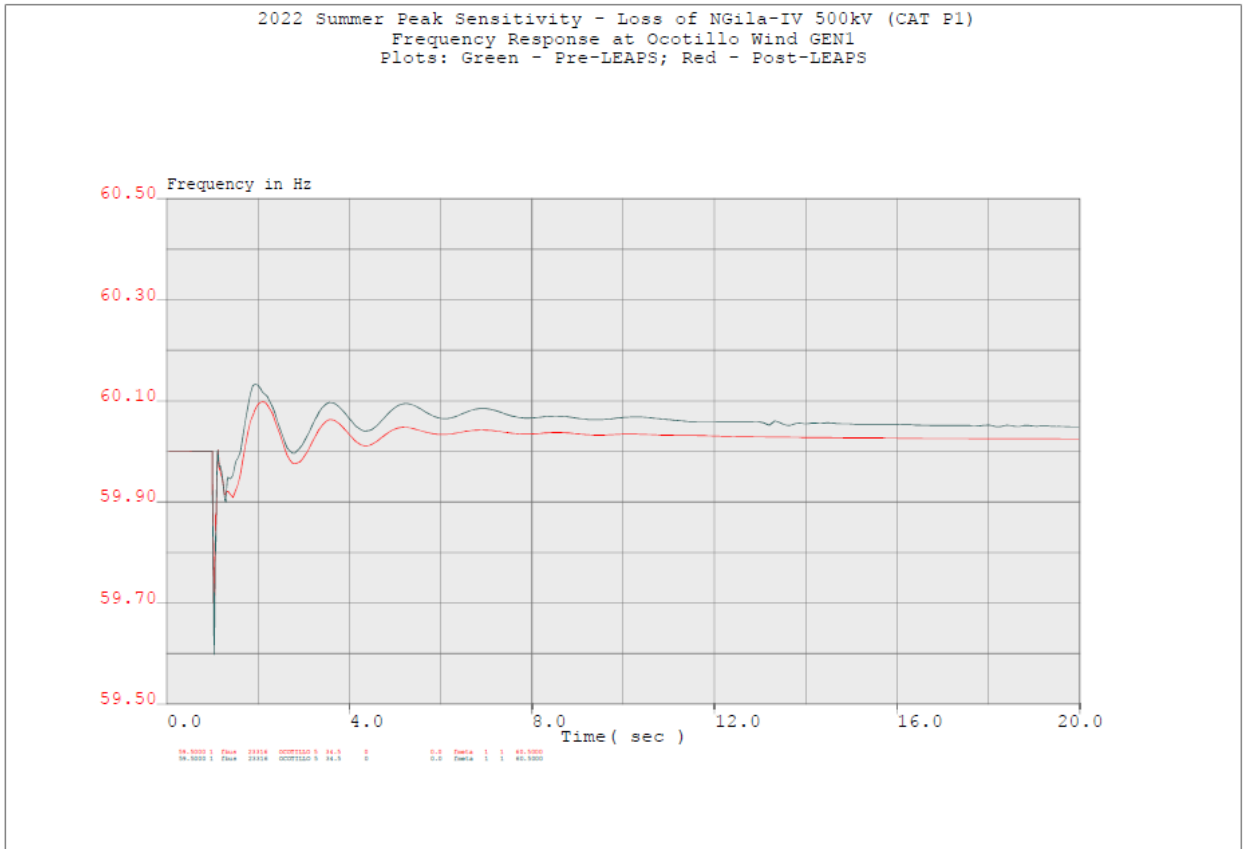


Figure 18, below, shows the response for the Ocotillo wind generation facility pre-LEAPS and post-LEAPS for the loss of the same 500 kV line. The PV plant frequency dipped by 0.402 Hz in the pre-LEAPS case whereas it dipped by 0.33 Hz in the post-LEAPS case. This results in an 18% improvement with LEAPS. The frequency overshoot for Drew PV improved by 26% from +0.133 to +0.098 Hz and the stabilization time improved by approximately 2 seconds.

Figure 18. Frequency Response for an Existing Wind Generator in San Diego Pre-LEAPS and Post-LEAPS



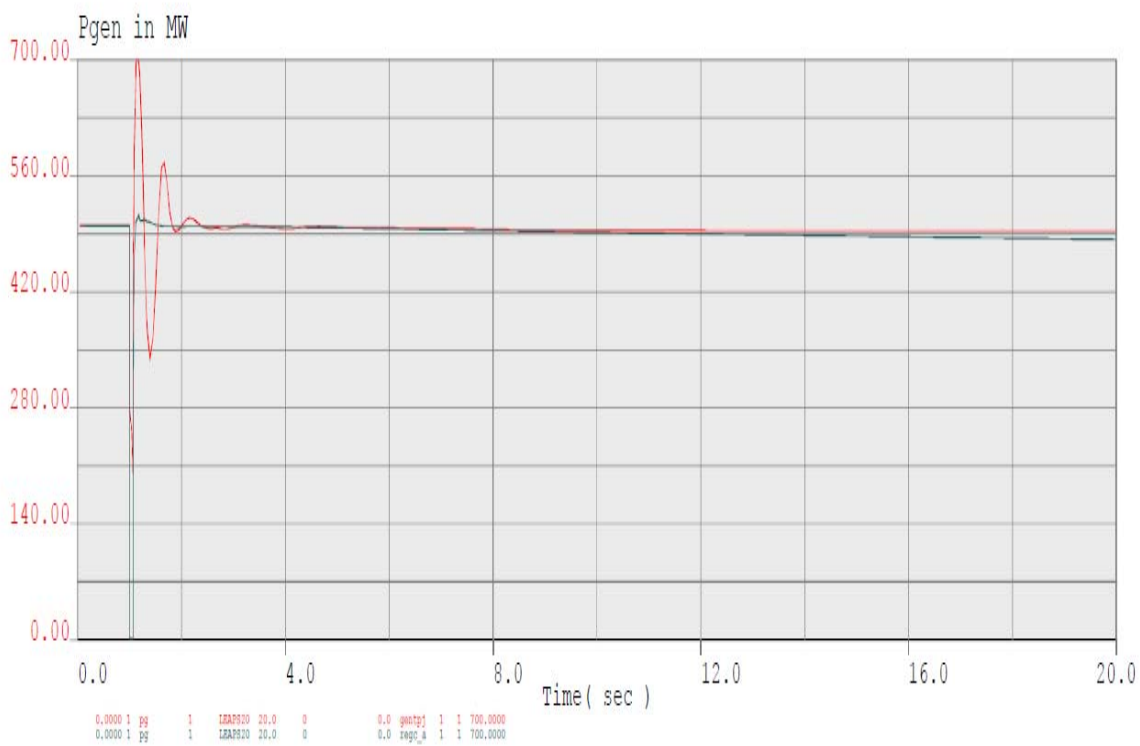
Q. Please describe your third study.

A. My third study is an analysis to assess LEAPS' ability to provide inertia response for system disturbances similar to the September 8, 2011 Southern California blackout. I simulated the generation response from an existing Solar PV and the proposed LEAPS project. **Figure 19** shows both plants generating 500 MW. Upon the loss of the 500-kV line, all 500 MW of PV generation dropped and recovered back to 500 MW. However, LEAPS generation dropped from 500 MW to 300 MW but also produced 700 MW which was 200 MW above its initial generation level (RED). This 200 MW is called "inertia" response. LEAPS help the system by (1) not losing all its generation and (2) producing 200 MW more energy before returning to its 500 MW level.

Q. What do you conclude?

A. My conclusion is that a hydroelectric generator performs better during contingencies and reduces the frequency deviations much better than a similar sized solar photovoltaic generator. This is due to the inherent inertial response contributed from the hydro generator whereas the inverter-based generators do not have mechanical inertia. The PV inverter control system must detect the fault and react to it, which constitutes a delay of few cycles. This can be seen in **Figure 19**, below, where the black plot is a PV generator and the red plot is hydroelectric generator. As mentioned, the real power output of the PV generator drops to zero while that of the hydro generator does not. So, when the event occurs, the hydro generator adds to the inertial response of the system, arresting the frequency drop and thereby improving the stability of the transmission grid. Also with the hydro generator the frequency returns to a level closer to the initial frequency.

Figure 19. Generation Response for an existing Solar PV and LEAPS in San Diego



Q. How would you sum this up?

A. The LEAPS project helps improve the stability of the system by:

1. Reducing both negative and positive frequency excursions,
2. Providing quicker frequency recovery to levels closer to pre-contingency, and
3. Reducing the time to reach stable operating levels.

By keeping a check on the frequency swings, the LEAPS project reduces the chances of instantaneous tripping of other generators, thereby reducing the risk of a cascading failure and potential blackouts.

Q. What other electric support services can LEAPS provide?

A. Frequency response, inertia, voltage support, phase shifting, reactive and black start capabilities are sometimes lumped together into "electric reliability services." LEAPS provides reactive power (VAR) support by providing and absorbing reactive power. It will be capable of moving up or down by 500 MVAR, similar to a synchronous condenser, like a gas-fired power plant, or shunt capacitors and reactors that are typically used as transmission devices to control the voltage on the grid. LEAPS also provides black start capability and is able to quickly utilize its three large phase shifters to automatically re-route power when needed, based on the angular separation between the main substations similar to the phased angle technologies. Operating efficiency of electric transmission system can be improved by using appropriate FACTS devices. Phase shifting transformer is one of the devices in the FACTS family which can be used for power control in a network.[66]

[66] As renewable energy continues to expand, the transmission grids are reaching their limits in many areas. One way of avoiding bottlenecks is to distribute load on parallel sections. To distribute load, the phase shifter transformer changes the phase angle between the transformer's primary and secondary side as required. The tap-changer used must have a large number of switching steps and operate at very high-power levels. The more finely the active power

Q. What is the avoided generation interconnection cost?

A. As shown by the ISO, TEAM Public Policy Benefits #3 shows that LEAPS is able to reduce the amount of nameplate renewables generating capacity to achieve California's 50% RPS goal. The avoided renewable generation capital cost also has an avoided transmission interconnection cost because generators that are not built do not trigger the need for transmission upgrades that must, ultimately, otherwise be paid for by consumers. The avoided transmission interconnection cost is based on the reduced renewable capacity to meet the state's 50% RPS goal with LEAPS in service multiplied by a price of $22/kW-year.[67] The resulting levelized annual benefits based on 511 MW

Table 13 below summarizes the amount of solar or wind needed under each of the ISO four sensitivities before and after LEAPS. LEAPS eliminates the need for 148 MW to 323 MW and from 108 MW to 188 MW of solar and wind overbuild respectively. The avoided interconnection cost is calculated by the avoided renewable generation name place capacity by a price of $22/kW-year.[68] This results in savings that ranges from $2.4 million to $7.1 million per year. This annual revenue requirement for the avoided interconnection cost is held constant throughout the life cycle of the project.

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is graduated, the more tap-change operations are possible. The tap-changer for the phase shifter transformer is frequently adapted to the specific requirements.

[67] http://www.caiso.com/Documents/BulkEnergyStorageResource-2015-2016SpecialStudyUpdatedfrom40to50Percent.pdf at page 17.

[68] http://www.caiso.com/Documents/BulkEnergyStorageResource-2015-2016SpecialStudyUpdatedfrom40to50Percent.pdf at page 17.

Table 13. Avoided Interconnection Cost Summary

	Net Renewable Generation decreased and annual avoided cost			
Summary of Avoided Interconnection Costs	Solar case (MW)	Wind Case (MW)	Solar Case ($M)	Wind Case ($M)
Sensitivity #1 - Summary of the ISO analysis of the Updated Default Scen	163	112	$3.6	$2.5
Sensitivity #2 - Summary of the ISO analysis of the Updated Default Scenario with Non - Dispatchable CHP (2026 Base case)	323	188	$7.1	$4.1
Sensitivity #3 - Summary of the ISO analysis of the Updated Default Scenario with 2015 IEPR Mid -AAEE Sensitivity (2026 Base case)	194	115	$4.3	$2.5
Sensitivity #4 - Summary of the ISO analysis of the Updated Default Scenario with 4-tier Curtailments Prices (2026 Base case)	148	108	$3.3	$2.4

Q. How can LEAPS help to avoid transmission expansion costs?

A. As mentioned before, the reliability benefits and avoided cost category includes three benefit sub-categories. The second sub-category is the avoided large transmission investments related to the reduction of RPS costs associated with the 323 MW solar and 188 MW wind. It was not clear from CAISO's analysis whether any transmission will be needed to achieve this 50% RPS goal, so I have only included the avoided transmission cost of RPS due to LEAPS which is (323 MW + 188 MW) * solar capacity factor * CAISO TAC (15 $/MWH) = $35 million.

Q. Did you calculate the LEAPS reliability service benefits?

A. Reliability services, such as frequency control, black start, and the avoidance of Reliability Must Run contract was not included in the CAISO study, however I have calculated the benefits of this sub-category for this testimony. LEAPS provide much needed grid resiliency and its electric reliability service benefit is estimated to be $50/kW-year[69] and so the annual benefit for this category due to LEAPS is $30 million/year based on a capacity of 600 MW.

Q. What other avoided cost did you consider?

A. Reduced costs for RMR contracts is a likely benefit. There are, however, several things that point to the kinds of savings consumers could see.

[69] http://www.energy.ca.gov/2013publications/CEC-500-2013-044/CEC-500-2013-044.pdf. Prepared by CED, SCE and Quanta Technology, March 2012, Table 12, page 66. .

1 For example, the CAISO estimated that the annualized fixed costs for a hypothetical
2 combined cycle unit are $166/kW-year.[70] Their analysis showed that net revenues for the same
3 combined cycle unit in the CAISO may have ranged between $11/kW-year in northern California
4 and $22/kW-year in southern California given day-ahead and real-time market conditions that
5 existed in the ISO in 2016.[71] Similarly, the California Energy Commission estimated that the
6 annualized fixed costs for a combustion turbine is $177/kW-year.[72] Their analysis showed that
7 net revenues for a similar combustion turbine in the CAISO may have ranged between $5/kW-
8 year and $17/kW-year for real-time market conditions that existed in the CAISO in 2016.[73] In
9 both cases net revenues earned through the market fell significantly below expected fixed costs.
10 This underscores the need for new reliability resources to recover additional costs from longterm
11 bilateral contracts.[74]
12 More recently, on October 30, 2017, the CAISO Board granted Calpine's Metcalf Energy
13 Center Power Plant an RMR contract following Calpine's request to remove and declare the plant
14 unavailable citing concern that CAISO's capacity procurement mechanismprovided insufficient
15 return on their capital investment.[75] The plant is a 564 MW combined cycle commisioned in 2005

[70] Annual fixed costs are derived from California Energy Commission's Estimated Cost of New Renewable and Fossil Generation in California report which is published once every couple year. The annual fixed costs in this report are the average between IOU, POU and Merchant fixed costs reported in the March 2015 final staff report, Appendix E: http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SF.pdf.

[71] https://www.ISO.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf, page 52

[72] Annual fixed costs are derived from California Energy Commission's Estimated Cost of New Renewable and Fossil Generation in California report which is published once every couple year. The annual fixed costs in this report are the average between IOU, POU and Merchant fixed costs reported in the March 2015 final staff report, Appendix E: http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SF.pdf.

[73] https://www.ISO.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf, Page 52

[74] *Id*.

[75] http://www.ISO.com/Documents/Decision_ReliabilityMust-RunDesignation_MetcalfEnergyCenter-UpdatedMemo-Nov2017.pdf.

and is considered one of the most efficient units in California. FERC recenty accepted this contract for filing, but set it for hearing to decide whether the amount of the payment is just and reasonable.[76]

It is likely that gas fired resources in the San Diego area will require RMR contracts to provide local reliability services given the low expected energy prices. Since some of the local reliability services include local capacity as I have discussed, I elected to ignore the avoided cost of RMR contracts because LEAPS could provide both local capacity and similar reliability services required under an RMR contract.

Q. Can you summarize the TEAM Category #5 benefits – Reliability and avoided cost of other projects?

A. For the high solar penetration case, I calculated an avoided interconnection cost benefits of $7.1 million per year. The avoided transmission expansion cost is $28.2 million per year. The avoided reliability service cost is $30 million per year. Adding the three sub-categories results in a total reliability benefits and avoided cost benefit of $65 million per year for the high solar penetration case which I kept constant over the life of the project.

For the high wind penetration case, I calculated an avoided interconnection cost benefits of $3.1 million per year. The avoided transmission expansion cost is $18.8 million per year. The avoided reliability service cost is $30 million per year. Adding the three sub-categories results in a total reliability benefits and avoided cost benefit of $52 million per year for the high wind penetration case, which I kept constant over the life of the project.

[76] *Metcalf Energy Center, LLC*, 161 FERC ¶ 61,310 (2017)

VIII. SUMMARY OF THE LIFE CYCLE BENEFITS OF LEAPS

Q. Can you summarize your analysis of the total life cycle benefits realized from all five TEAM benefits categories?

A. The total life cycle benefits realized from the five TEAM categories are shown below for the solar and wind cases respectively.

Figure 20. LEAPS' Life Cycle TEAM Benefits – Solar Case

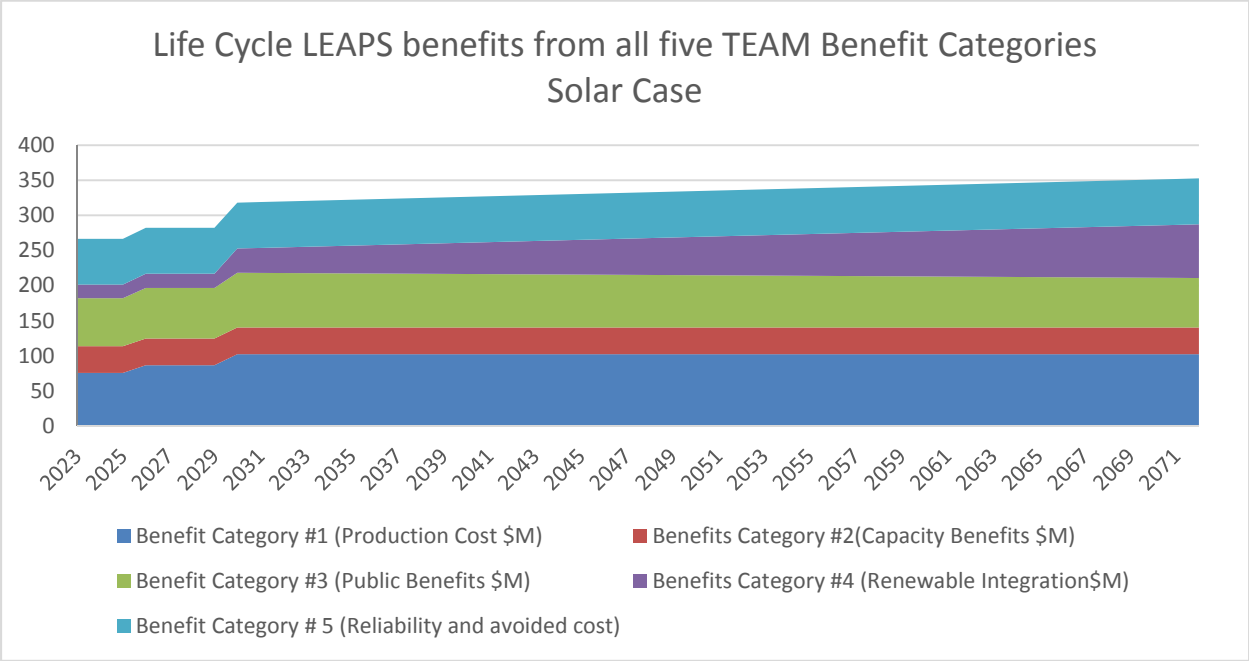
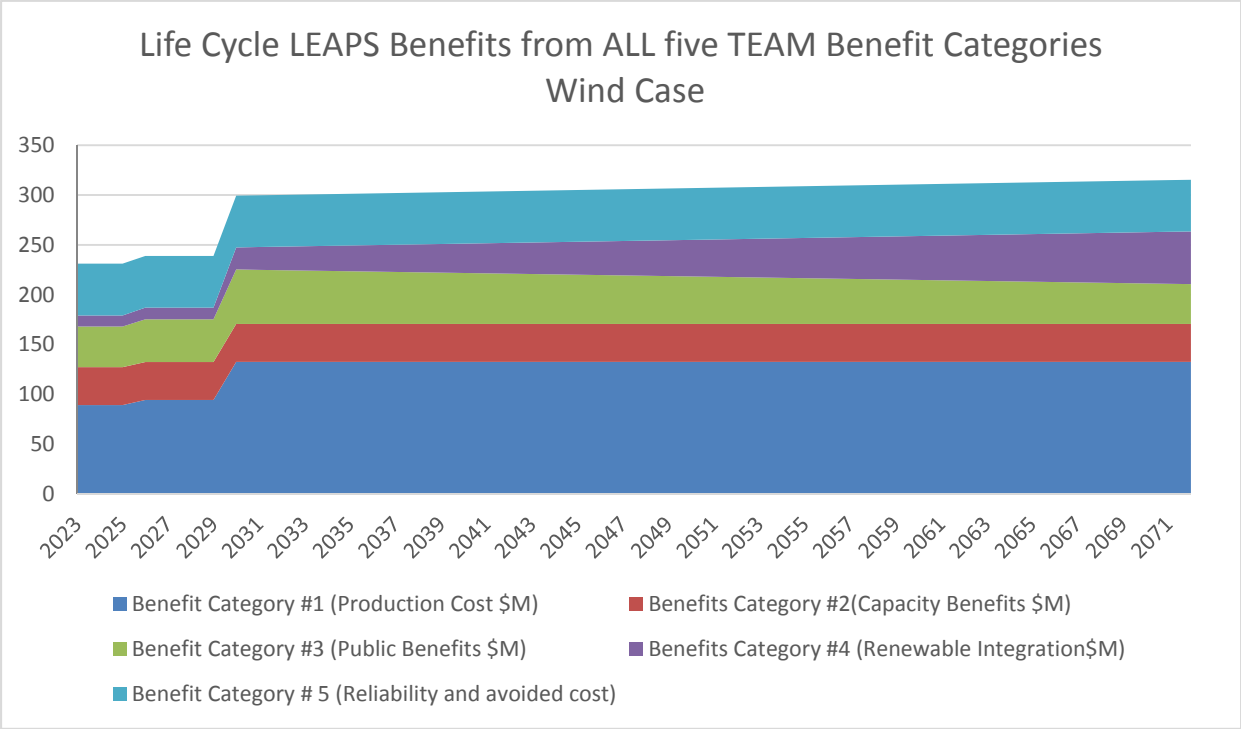


Figure 21. LEAPS' Life Cycle TEAM Benefits – Wind Case



Q. What is the total net present value benefits and cost of LEAPS?

A. The net present value benefit of LEAPS for the high penetration solar case is $5.424 billion. The LEAPS net present value cost is $3.083 billion. The BPV_BCR is 1.76:1.

Table 14. LEAPS Present Value Benefit to Cost Ratio – Solar Case

Benefits	NPV ($M)
Benefit Category #1 (Production Cost $M)	$1,663.20
Benefits Category #2 (Capacity Benefits $M)	$661.73
Benefit Category #3 (Public Benefits $M)	$1,284.85
Benefits Category #4 (Renewable Integration $M)	$676.97
Benefit Category # 5 (Reliability and avoided cost)	$1,137.15
Total Present Value Benefits	$5,423.89

Present Value Cost ($M)	$3,083.40

Total BPV_BCR	1.76

The net present value benefit of LEAPS for the high wind penetration case is $4.906 billion. The LEAPS net present value cost is $3.083 billion. The BPV_BCR is 1.59:1.

Table 15. LEAPS Present Value Benefit to Cost Ratio – Wind Case

Benefits	NPV ($M)
Benefit Category #1 (Production Cost $M)	$2,076.98
Benefits Category #2(Capacity Benefits $M)	$661.73
Benefit Category #3 (Public Benefits $M)	$823.88
Benefits Category #4 (Renewable Integration $M)	$439.82
Benefit Category # 5 (Reliability and avoided cost)	$903.79
Total Present Value Benefits	$4,906.20

Present Value Cost ($M)	$3,083.40

Total BPV_BCR	1.59

IX. LEAPS "UNCERTAINTY ANALYSIS

Q. Can you elaborate on the value of incorporating "Uncertainty Analysis"?

A. Decisions on whether to build new infrastructure tend to be challenging since decisions that are made today will be dealt with for 50 years. When in fact, there are risks and uncertainties about the future that could alter the projected value of a project. Future load growth, fuel costs, State energy policies, additions and retirements of generation capacities and the location of those generators, and availability of hydro resources are among some of the many factors impacting decision making. Some of these risks and uncertainties can be easily measured and quantified, and some cannot. There are two fundamental reasons why the TEAM considers risk and uncertainty in transmission evaluation.

First, changes in future system conditions can affect benefits from transmission expansion significantly. Historically the relationship between transmission benefits and underlying system conditions was found many times to be nonlinear. Thus, evaluating a transmission project based only on assumptions of average future system conditions might greatly underestimate or

overestimate the true benefit of the project and may lead to less than optimal decision making. To make sure we fully capture all impacts the project may have, we must examine a wide range of possible system conditions.

Second, historical evidence suggests that transmission upgrades have been particularly valuable during extreme conditions.[77]

Q. Did you apply all TEAM principles?

A. Yes, this section addresses the last TEAM principle called "Uncertainty Analysis" which completes the application of all TEAM principles in my analysis.

Q. Please explain how you applied uncertainty analysis to the benefit to cost results.

A. I utilized the CAISO's results for the 2026 year and supplemented with my own production cost modelling for the 2030 year using on CAISO's data and model, and applied the TEAM methodology to calculate the benefits for each category. The benefits derived from the two study years, "2026 Base" and "2030 Base" form the deterministic values of total benefits for LEAPS. I then used linear interpolation to calculate LEAPS' life cycle benefits and the present value benefits at the WACC rate. These two deterministic values are based on specific set on input assumptions. However, it does not measure the impact of risk and uncertainty. To measure the impact of risk and uncertainty, I used stochastic analysis to model the uncertainty associated with different input parameters that drive the magnitudes of the benefits for the LEAPS project. Stochastic analysis uses probabilistic representations of the future loads, natural gas prices, RPS targets, hydro and other generation availability. The combination of the deterministic and stochastic analysis results

[77] Professor Frank Wolak, chair of the CAISO's Market Surveillance Committee, estimated that a large inter-connection between WSCC and the eastern United States during the period June 2000 to June 2001 would have been worth on the order of $30 billion.
http://www.caiso.com/Documents/MSCOpiniononTransmissionExpansionAssessmentMethodology.pdf at page 10.9

in calculating a range of benefit outcomes given the uncertainties in the input parameters so that I can then calculate the Present Value Expected Benefits (PVEB) for the project.

Q. Can you elaborate on the input variables used to perform the Uncertainty Analysis for LEAPS?

A. Yes, Table 5.1 from the CAISO TEAM methodology[78] provide guidance on the types of input variables that are typically used to evaluate uncertainty:

Table 5-1: Typical sensitivity analyses

Sensitivity analyses	Note and typical variation
Load - High	+6% above forecast
Load - Low	-6% below forecast
Hydro - High	if applicable and data available
Hydro - Low	if applicable and data available
Natural gas prices - High	+50%
Natural gas prices - Low	-25%
CO2 price	If data available
CA RPS portfolios	If data available
Other sensitivities per requested	

I selected to perform sensitivity analysis for the load, hydro, natural gas, Mid-level Energy Efficiency and CA RPS consistent with the table above.

Q. How is the sensitivity analysis performed?

A. To assess the sensitivity of these input variables to the resulting benefits, I first calculated the probabilities of occurrences for 20 combinations (cases) of the five input variables. In other

[78] http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf, Table 5-1, page 26

words, the probability of occurrence is a factor that represents the variation from the deterministic base case (CAISO Sensitivity #2) assumptions as follows:

- High Load (HL) = +6% above base case load
- Low Load (LL) = -6% below base case load
- High Hydro (HH) = wet hydro year
- Low Hydro (LH) = dry hydro year
- High Natural Gas Prices (HG) = +50% of base case natural gas assumption
- Low Natural Gas Prices (LG) = -25% of base case natural gas assumption
- High RPS (HRPS) = Increasing RPS capacity to achieve GHG emission target of 30 MMT, and
- High Energy Efficiency (HEE) = 2015 IEPR High-AAEE instead of the Mid-AAEE in the base case

Next and consistent with the fourth TEAM principle ("explicit uncertainty analysis"), the benefits of LEAPS are considered in the context of uncertainties that will unfold over the life of the project. I quantified the impact of this uncertainty by developing cases with different levels of input assumptions for load, hydro conditions, gas prices, RPS capacity and energy efficiency. I believe that these cases cover a reasonable range of possibilities. I then calculated expected benefits across these cases considering their probabilities. In addition, we consider LEAPS' "insurance benefit" by calculating benefits under various possible contingencies. In the expected benefit calculation, I focused on the five key variables just mentioned, defining 20 combinations in each year. For the cases where I varied load and gas prices, I examined three levels: high (H), base (B), and low (L). For the hydro generation, I also examined three levels: wet (W), base (B), or dry (D) year. I determined the values of the demand and gas price cases by analyzing the

historical accuracy of predictions of those variables, comparing CEC forecasts of loads and prices over the past 20 years and historical hydro production to their realized levels. Load distributions are characterized using normal distributions fitted to the historical forecast errors, while gas prices follow a log-normal distribution. The "L" and "H" levels used in the load, hydro and gas sensitivity cases are based on 90% confidence intervals from their distributions. For loads, those levels vary only slightly from the base case, while for natural gas and hydro the differences are large. I also examined the impact of two more variables, RPS capacity and energy efficiency. I included high RPS sensitivity since most likely the State will continue to move toward higher RPS to meet lower emission standards. Likewise, I included a sensitivity for higher energy efficiency standards.

There are 3x3x3x3x3 =243 possible combinations or cases that could be assessed for the five uncertain variables. This is too many to simulate. Therefore, I considered a smaller but representative subset of 20 cases in the expected benefits calculations for the high solar penetration case as follows:

1. Base values for all five variables (1 case),
2. Base values for four of the five variables, and the low value for the fifth variable (3 cases, case 2, 3 and 4). I did not consider the "low RPS" and "low EE" as a valid scenario.
3. Base values for three of the five variables, and the high value for the remaining variables (4 cases, case 5,6,7, and 8), and
4. Additional cases representing plausible combinations of extreme scenarios such as a high stress condition (high load, high gas price, dry hydro, high RPS), economic boom (high load and gas prices), or recession induced by high fuel prices (low load, high gas price).

5. Another consideration in selecting these cases was to make it possible for probabilities to be chosen so that the means and standard deviations of each of the individual variables matched the assumptions, and for correlations to be reasonable (for instance, I expect a positive correlation between dry conditions and high demand due to warm temperatures) (12 cases).

Table 16 shows the selected 20 cases for 2026 and 2030 cases.

Table 16. Sensitivity Cases for the Uncertainty Analysis

Cases	Loads	Hydro	Gas	RPS	EE
1	B	B	B	B	B
2	B	B	L	B	B
3	B	L	B	B	B
4	L	B	B	B	B
5	B	B	B	H	H
6	B	B	H	H	B
7	B	H	H	B	B
8	H	B	B	B	H
9	H	L	H	H	B
10	H	H	L	B	B
11	H	H	H	B	H
12	H	B	B	H	H
13	H	H	L	H	H
14	L	L	L	B	B
15	L	B	L	H	H
16	L	L	L	B	H
17	L	B	L	B	B
18	L	L	B	H	H
19	L	L	H	H	B
20	L	L	H	B	B

I calculated the Expected LEAPS Benefits following the methodology outlined by CAISO TEAM.[79] Next, after selecting representative cases, it is necessary to determine the probability that each of the selected case could occur in the future. Each case is a realization of the various dimensions of uncertainty in future system conditions. However, the input data described above only provides an estimate of the marginal distribution of each of these dimensions. For example, I used information on the marginal distributions of future hydro conditions and gas prices, but not their joint density. Consequently, I pick values for the joint probability of each set of future system conditions. I calculated these probabilities using a non-linear program that maximizes the logarithm of likelihood (the sum of the logarithm of the joint probabilities) of observing the 20 cases subject to the constraint that the joint probabilities replicate the first two moments of the marginal distribution of each variable. Mathematically, I chose the Pi for cases i = 1, 2,..,20 to maximize the sum of Ln (Pi) subject to the constraints: Σ Pi = 1, and the mean and standard deviation for each variable implied by these joint probabilities match the assumed values for the marginal distribution of each variable. The Pi for each case is added in **Table 17**.

Table 17. Probability (Pi) for Sensitivity Cases

Cases	Loads	Hydro	Gas	RPS	EE	Pi
1	B	B	B	B	B	13.50%
2	B	B	L	B	B	3.00%
3	B	L	B	B	B	6.60%
4	L	B	B	B	B	7.50%
5	B	B	B	H	H	11.00%
6	B	B	H	H	B	7.70%
7	B	H	H	B	B	3.50%
8	H	B	B	B	H	2.90%
9	H	L	H	H	B	1.60%

[79] https://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/files/Using%20Market%20Simulations%20for%20Economic%20Assessment%20of%20Transmission%20Upgrades_Applications%20of%20the%20California%20ISO%20Approach.pdf.

Cases	Loads	Hydro	Gas	RPS	EE	Pi
10	H	H	L	B	B	4.40%
11	H	H	H	B	H	1.20%
12	H	B	B	H	H	2.70%
13	H	H	L	H	H	5.50%
14	L	L	L	B	B	3.80%
15	L	B	L	H	H	10.50%
16	L	L	L	B	H	2.00%
17	L	B	L	B	B	3.10%
18	L	L	B	H	H	3.55%
19	L	L	H	H	B	1.54%
20	L	L	H	B	B	4.50%

Q. How did you calculate the Benefit Categories for these 20 cases?

A. I calculated each of the five benefit categories under each case by multiplying the results of the two base cases by its correspondent probability of occurrence to get the total annual benefits. The results are then expanded over the life cycle of the project.

Q. How did you arrive to the Expected Benefits of LEAPS?

A. Using this uncertainty analysis, I was able to calculate the expected benefits of the LEAPS under each TEAM benefit category. I then calculated the Present Value Expected Benefits for each category at the Real WACC. I calculated the Expected PV BCR by dividing the Present Value Expected benefits by the Present Value project cost. The Expected PV BCR was calculated to equal to 1.72:1 for the high solar penetration case and 1.54:1 for the high wind penetration case.

The Expected PV BCR of 1.72:1 is slightly lower than the Base PV BCR of 1.76:1. The base case PV BCR of 1.76:1 has a present value life cycle total benefits of $5.42 billion while the Expected PV BCR has a present value life cycle benefits of $5.3 billion. The Expected Benefits calculation revealed that LEAPS has a net $120 million loss to the ratepayers when considering the uncertainty of the input variables that drive the project benefits. **Table 18** provides a summary

of how the EPV_BCR varies with the uncertainty of input variables where the range is from 1.15:1 to 2.12:1.

Table 18. EPV_BCR for the Sensitivity Cases

Cases	Loads	Hydro	Gas	RPS	EE	Pi	EPV_BCR
1	B	B	B	B	B	13.50%	1.76
2	B	B	L	B	B	3.00%	1.32
3	B	L	B	B	B	6.60%	1.79
4	L	B	B	B	B	7.50%	1.5
5	B	B	B	H	H	11.00%	1.81
6	B	B	H	H	B	7.70%	1.98
7	B	H	H	B	B	3.50%	2.12
8	H	B	B	B	H	2.90%	1.65
9	H	L	H	H	B	1.60%	2.1
10	H	H	L	B	B	4.40%	1.76
11	H	H	H	B	H	1.20%	1.88
12	H	B	B	H	H	2.70%	1.76
13	H	H	L	H	H	5.50%	1.84
14	L	L	L	B	B	3.80%	1.32
15	L	B	L	H	H	10.50%	1.93
16	L	L	L	B	H	2.00%	1.15
17	L	B	L	B	B	3.10%	1.33
18	L	L	B	H	H	3.55%	1.28
19	L	L	H	H	B	1.54%	1.8
20	L	L	H	B	B	4.50%	1.45

Q. What other observations do you have?

A. I note that 8 out of 20 sensitivity cases resulted in equal or lower Expected PV BCR compared to the Base Expected PV BCR and 11 out of 20 cases resulted in higher or equivalent Expected PV BCR compared to the Base Expected PV BCR. In my opinion, this shows a robustness in the project's Expected benefit. Also, all cases show an Expected PV BCR greater than 1.15:1.

X. OTHER BENEFITS THAT ARE NOT QUANTIFIED

Q. Will LEAPS provide other benefits in addition to the ones that you have already discussed?

A. Yes. LEAPS will provide additional operational benefits that I identify in ***Table 19***. Although these eight operational uses are not quantified in this testimony, it is my experience that LEAPS can provide these benefits to consumers which from a total benefits-to-cost perspective, will provide an upside to ratepayers.

Table 19. LEAPS' Operational Uses without Quantifiable Benefits

Operational Use	Value Metrics	Methodology used to Calculate Benefits
Power Quality	LEAPS can protect the loads downstream against short-duration Event that Affect the Quality of power Delivered to loads. These short duration events include low power factor, harmonics and interruptions of services.	the Power Quality benefits are not included in this analysis since LEAPS is HV transmission and not directly connected to distribution. Value of 50 $/KW-YR. Table 11, page 64
Intermittency Capacity Firming	The benefit for firming output from renewable energy generation is related to the cost that can be avoided for other electric supply capacity. If renewable energy generation output is constant during times when demand is high, then less conventional generation capacity is needed, otherwise, additional capacity is needed on standby	the Intermittency capacity Firming Benefits that LEAPS can provide are not included in this analysis. Its estimated to be 12 $/KW-YR. Table 11, page 64
Intermittent Grid Integration	When wind and solar experience sudden reduction in output, the grid need energy on standby to response to the volatility and variability of these intermittent resource.	the Intermittency Grid Integration or energy firming benefits that LEAPS can provide are not included in this analysis. the benefits are estimated to be 50 $/KW-YR. Table 11, page 64. Its extremely difficult to separate load followings from grid integration and as a conservative measure, we did not include these benefits
Demand response	LEAPS variable pump technology and the ability to ramp up and own very quickly without restriction on the number on stops and starts and without any minimum start time and minimum down time qualify for demand response services	leaps can provide an instand demand response by creating a 600 MW load or shave off 600 MW of load

Q. What other method did you use to quantify the LEAPS benefits?

A. I have supplemented the TEAM based method with the CPUC's Integrated Resource Planning assumptions and RESOLVE software. The range of benefit-to-costs for LEAPS is from 1.53 to 3.8.

Exhibit NHC-D shows the analysis and calculation of the project benefits using the CPUC's method and software.

Q. Does this conclude your testimony?

A. Yes.

Q. Thank you.

STATE OF CALIFORNIA)
) ss
COUNTY OF Sacramento)

I, Ziad Alaywan, being duly sworn, depose and say as follows:

The foregoing "Affidavit of Ziad Alaywan P.E. in Support of Nevada Hydro Company, LLC Petition for Declaratory Order" was prepared by me, or under my direction and supervision, and the factual statements contained in such Affidavit are true and correct to the best of my knowledge, information and belief.

Further affiant saith not.

Ziad Alaywan P.E.

REGISTERED PROFESSIONAL ENGINEER
ZIAD ALAYWAN
13880
ELECTRICAL
STATE OF CALIFORNIA

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

On this 8 day of March, 2018, before me, the undersigned notary public, personally appeared Ziad Alaywan and acknowledged to me that he signed the foregoing document voluntarily for the purposes stated therein. I identified Ziad Alaywan to be the person whose name is signed on the foregoing document by the following satisfactory evidence of identity (check one):

___ Identification based on my personal knowledge of his identity, or

✓ Current government-issued identification bearing his photographic image and signature.

See Attached Notary Acknowledgment Certificate

Notary Public

My commission expires: Dec 30, 2020
(SEAL)

J. NAGEL
Notary Public - California
Sacramento County
Commission # 2177570
My Comm. Expires Dec 30, 2020

CALIFORNIA ALL-PURPOSE ACKNOWLEDGEMENT **CIVIL CODE § 1189**

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

STATE OF CALIFORNIA }
} ss.
COUNTY OF SACRAMENTO }

On March 8, 2018, before me, J. Nagel, a notary public in and for the State of California, personally appeared Ziad Alaywan, who proved to me on the basis of satisfactory evidence to be the person whose name is subscribed to the within instrument and acknowledged to me that he executed the same in his authorized capacity, and that by his signature on the instrument the person, or the entity upon behalf of which the person acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

J. NAGEL
Notary Public - California
Sacramento County
Commission # 2177570
My Comm. Expires Dec 30, 2020

NOTARY SIGNATURE

NOTARY SEAL

OPTIONAL

Though the information below is not required by law, it may prove valuable to persons relying on the document and could prevent fraudulent removal and reattachment of this form to another document.

Description of attached document

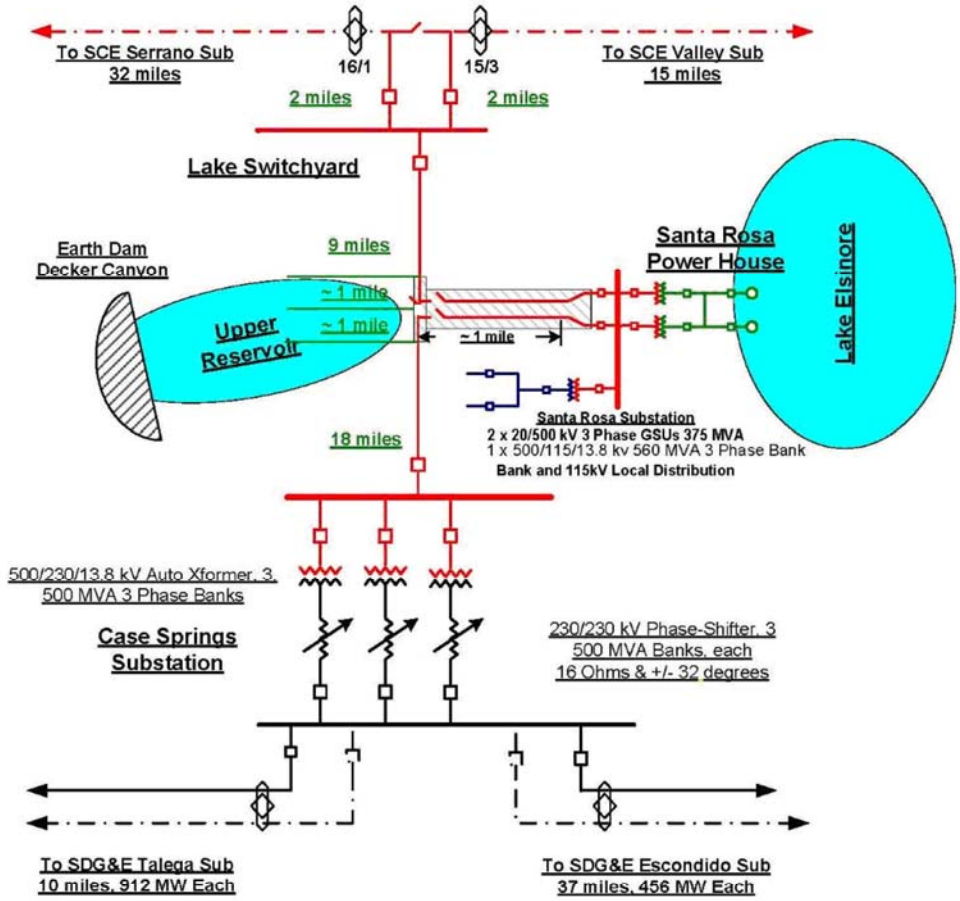
Title or Type of Document: Affidavit of Ziad Alaywan P.E. in Support of Nevada Hydro Company, LLC Petition for Declaratory Order
Document Date: March 8, 2018 Number of Pages: 1
Signer(s) Other Than Named Above: Not Applicable

Capacity(ies) Claimed by Signer(s)

Signer's Name: Ziad Alaywan	Signer's Name:
☐ Corporate Officer – Title(s)	☐ Corporate Officer – Title(s)
☐ Partner - ☐ Limited ☐ General	☐ Partner - ☐ Limited ☐ General
☒ Individual ☐ Attorney in Fact	☐ Individual ☐ Attorney in Fact
☐ Trustee ☐ Guardian or Conservator	☐ Trustee ☐ Guardian or Conservator
☐ Other:	☐ Other:
Signer Is Representing: Ziad Alaywan, P.E.	Signer Is Representing:

EXHIBIT NHC - A

LEAPS PROJECT CONCEPTUAL SINGLE LINE DIAGRAM



Notes:
1. LEAPS 500Kv Line, conductors double bundle (two per phase) Bluebird 1256 ASCR
2. Talega - Case Spring 230KV, double bundle Falcon 1033 ASCR, double circuit
3. Case Spring - Escondido 230KV, single conductor Falcon 1033 ACSR, double circuit
4. GIL rated at 4000amps continuous load
5. 500KV Lines
6. 230KV Lines
7. 115KV Lines
8. 20 KV Lines

4.

EXHIBIT NHC – B

OVER-GENERATION EXAMPLES

The examples below describe how generators can be compensated when over-generation conditions occur.

<u>Example 1 – Economic Curtailment (Real-Time Schedule Reduction from Day-Ahead Market Awards)</u>

When a generator is awarded an hourly MW schedule in the California Independent System Operator's (ISO) Day-Ahead market, the generator is then paid for energy that the ISO expects it to produce at the Day-Ahead Locational Marginal Price (LMP) node where the generator interconnects to the ISO grid.

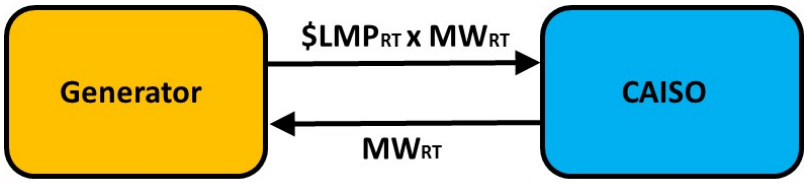
Figure 22. Generation Schedule and Payment because of Day-Ahead Market Awards

If the generator's schedule in an hour is 10 MW, and the ISO's Day-Ahead market clearing price as represented by the LMP is $25/MWh, then the payment by the ISO to the generator is $250 (10 MW x $25/MWh). This payment by the ISO to the generator is independent of how much energy the generator produces.

On the flow day, the ISO operates its ISO Real-Time market. The ISO runs its Real-Time market intra-hour, but for simplicity, assume that the intra-hour Real-Time market results average to a single hourly price that can be compared to the ISO's Day-Ahead hourly price.

Over-generation (a condition when supply exceeds demand within the ISO's balancing area) occurs when ISO Day-Ahead market supply and demand MW awards from the Day Ahead market run differ from the supply or demand produced in real-time resulting in additional energy supply that outstrips demand. When over-generation occurs, market prices fall, even to a negative value. When Real-Time prices fall far enough, generators are incented to not produce energy thereby reducing the over generation. The generator buys back the energy it scheduled to the ISO in the Day-Ahead market at Real-Time prices.

Figure 23. Generation Schedule Reduction and Payment because of Real-Time Market Awards



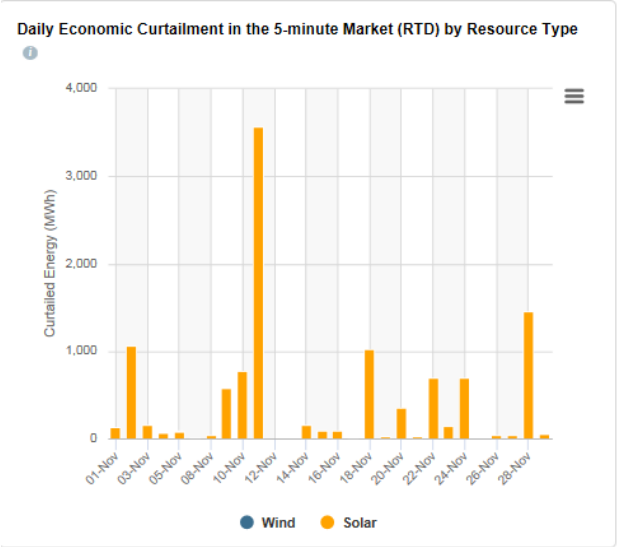
If the ISO Real-Time LMP clears at negative $30/MWh, and the generator has a bid in the ISO's Real-Time market to reduce its schedule if the LMP clears below a bid price of negative $10/MWh, then the generator's bid to buy energy from the ISO's Real-Time market will be accepted. The generator's schedule is 10 MW purchase at the LMP clearing price of negative $30/MWh. The payment from the generator to the ISO is negative $300. Because the payment amount from the ISO to the generator is negative, it is $300 received by the generator.

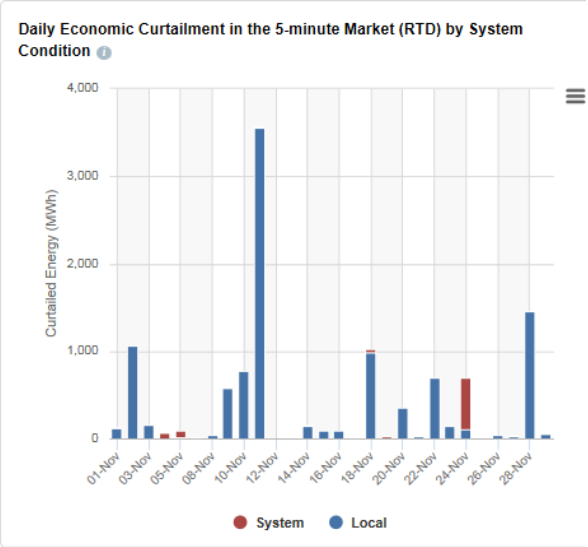
The total proceeds to the generator from the Day-Ahead and Real-Time markets is $550 ($250 from the ISO Day-Ahead market, and $300 from the ISO Real-Time market). Note that the generator produced no energy but was paid $550.

The reduction in output compared to schedule is called "Economic Curtailment" because the generator was curtailed based on economics (its bid into the ISO's markets) and resultant schedule

based on ISO LMP market clearing prices. The ISO has produced a renewable energy report that tracks Economic Curtailment shown in the graphs below[80]. In November 2017, the ISO Economically Curtailed nearly 11,000 MWh of renewable resources, primarily solar. From May 2014 through November 2017, over 900,000 MWh of renewable energy has been Economically Curtailed.

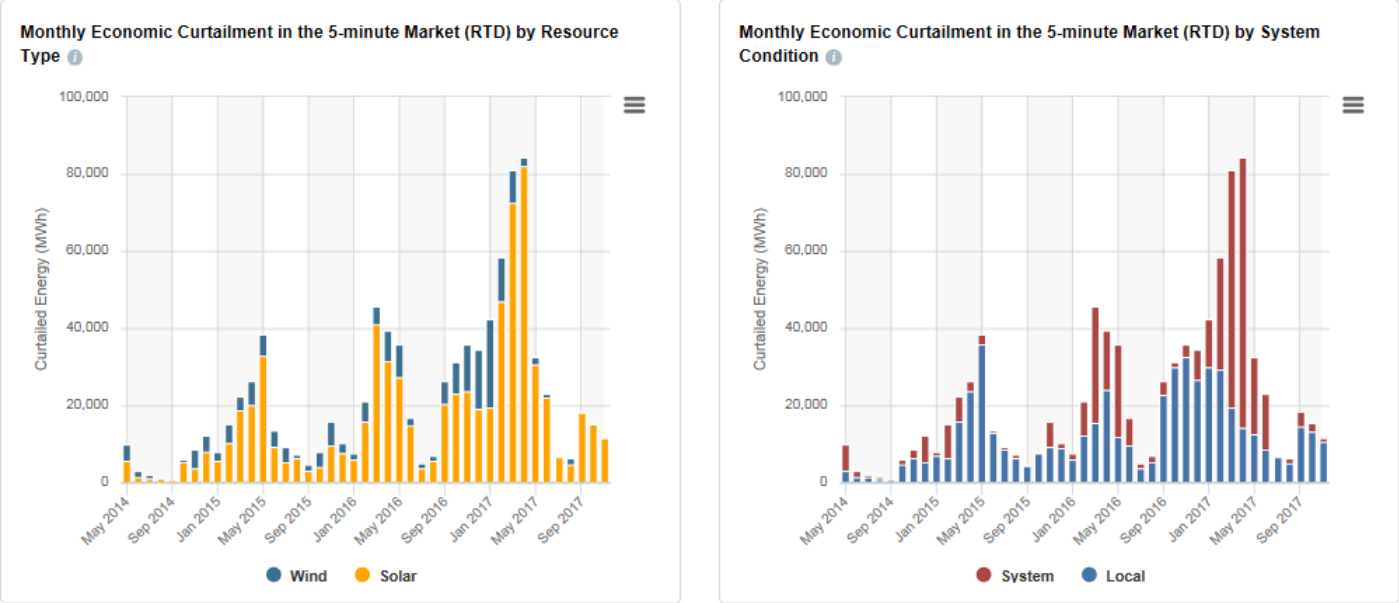
Figure 24. Economic Curtailment MWh by Day for November 2017





[80] California ISO Monthly Renewables Performance Report, VER Curtailment tab, Economic Curtailment Dropdown at: http://www.ISO.com/Documents/MonthlyRenewablesPerformanceReport-Nov2017.html.

Figure 25. Economic Curtailment MWh by Month for 2017



<u>Example 2 – Economic Curtailment (Real-Time Schedule Reduction from Fifteen-Minute Market Awards)</u>

A generator can also receive benefits when reducing output with only a Real-Time energy bid. It works the same way as described in Example 1, but there is no Day-Ahead schedule for the generator. Rather the generator is awarded a MW schedule in the 15-minute market, and offers a bid in the ISO's Real-Time market to reduce its output for a price.

Similar to the ISO Day-Ahead market, when a generator is awarded an hourly MW schedule in the ISO's Fifteen-Minute market, the generator is paid for energy that the ISO expects it to produce at the Fifteen-Minute LMP node where the generator interconnects to the ISO grid.

If the generator's schedule in an hour is 10 MW, and the ISO's Fifteen-Minute market clearing price as represented by the LMP is $25/MWh, then the payment by the ISO to the generator is

$250 (10 MW x $25/MWh). Similar to the Day-Ahead market, this payment by the ISO to the generator is independent of how much energy the generator produces.

Again, if the ISO Real-Time LMP clears at negative $30/MWh, and the generator has a bid in the ISO's Real-Time market to reduce its schedule if the LMP clears below a bid price of negative $10/MWh, then the generator's bid to buy energy from the ISO's Real-Time market will be accepted. The generator's schedule is 10 MW purchase at the LMP clearing price of negative $30/MWh. The payment from the generator to the ISO is negative $300, and $300 received by the generator.

The total proceeds to the generator from the Fifteen-Minute and Real-Time markets is $550 ($250 from the ISO Fifteen-Minute market, and $300 from the ISO Real-Time market). Note that the generator produced no energy but was paid $550.

Example 3 – Exceptional and Self-Schedule Curtailment

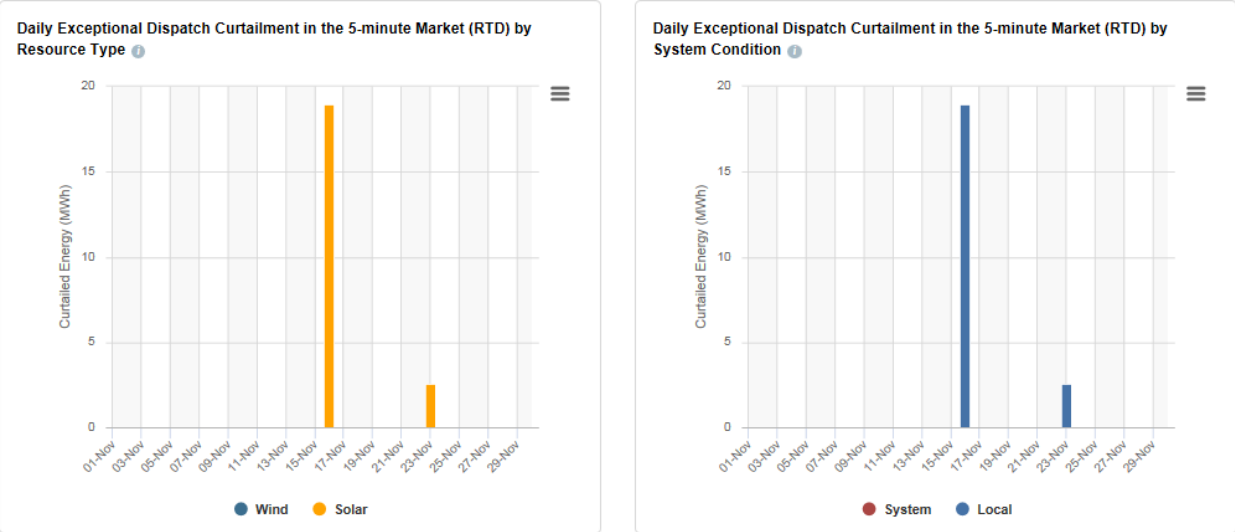
If the ISO's Real-Time market does not have enough decremental energy bids (generators' bids to buy back energy that they scheduled in the ISO market), the ISO may have to resort to ordering generators to reduce output. At that point, the ISO is ensuring reliability by acting outside the market. The LMP clearing price should reflect the over-generation condition and be negative.

If the ISO Real-Time LMP clears at negative $30/MWh, the generator has a schedule of 10 MW from the ISO's Fifteen-Minute market, with a Fifteen-Minute market LMP of $25/MWh, and the generator produces 0 MWh because of following the ISO's order to reduce output, then the generator would be paid $300 by the ISO (10 MW x negative $30/MWh). That amount is in addition to the $250 that it was paid in the Fifteen-Minute market for its 10 MW schedule at the

Fifteen-Minute market LMP of $25/MWh. Again, the generator is paid $550 total for not producing energy.

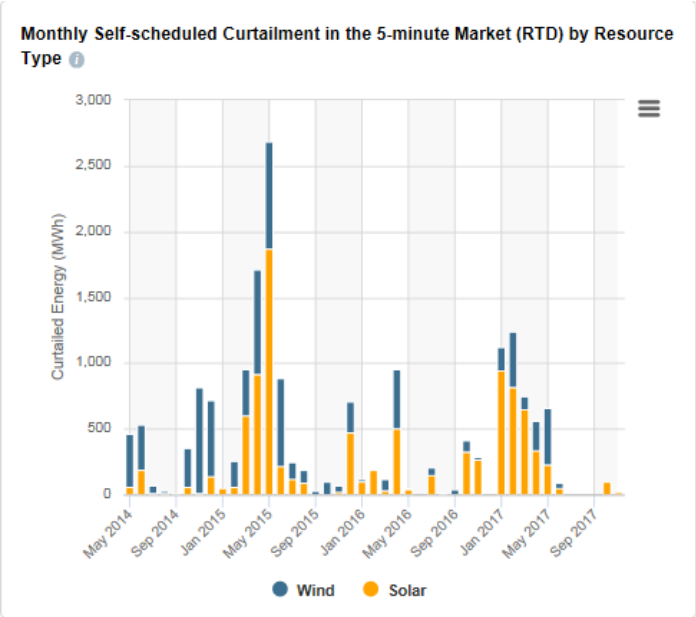
The reduction in output compared to schedule is called "Exceptional Dispatch", or "Self-Schedule Curtailment" because the generator was curtailed based on direction from the ISO outside the market. The ISO has produced a renewable energy report that tracks Exceptional and Self-Schedule Curtailment shown in the graphs below[81]. In November 2017, the ISO's Exceptional and Self-Schedule Curtailment was only 20 MWh. From May 2014 through November 2017, approximately 15,500 MWh of renewable energy has been reduced through Exceptional and Self-Schedule Curtailment.

Figure 26. Exceptional and Self-Schedule Curtailment MWh by Day for November 2017



[81] California ISO Monthly Renewables Performance Report, VER Curtailment tab, Exceptional and Self Schedule Curtailment Dropdown at: http://www.ISO.com/Documents/MonthlyRenewablesPerformanceReport-Nov2017.html.

Figure 27. Exceptional and Self-Schedule Curtailment MWh by Month for 2017



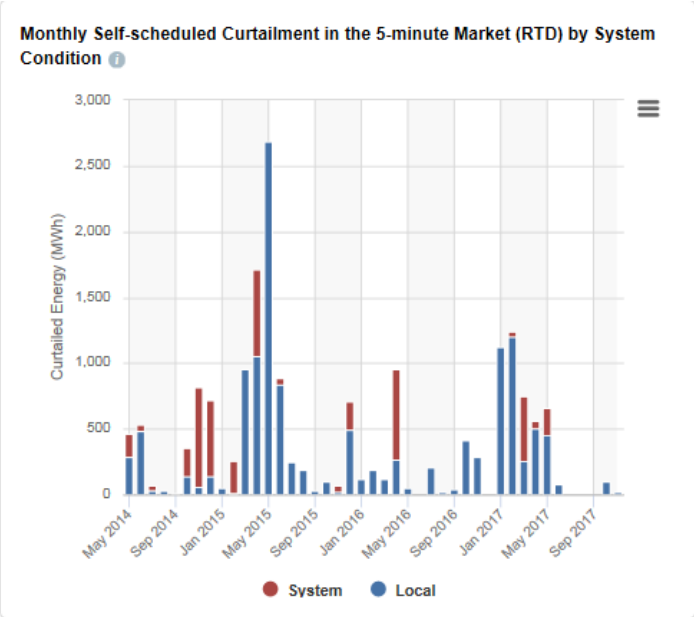


EXHIBIT NHC – C

POWER FLOW ANALYSIS DEMONSTRATING LCR, TRANSMISSION UTILIZATION AND RELIABILITY BENEFITS FOR THE SCE/SDGE AREAS

LEAPS is expected to be in service in 2022 timeframe. The base case that was picked for the analysis is ISO board approved 2017/2018 transmission planning case for the year of 2022 focused on San Diego area (case name B2_22P_SDGE_V1.sav). The projected load extracted from the base case for the year of 2022 in SDGE is 4,551 MW.

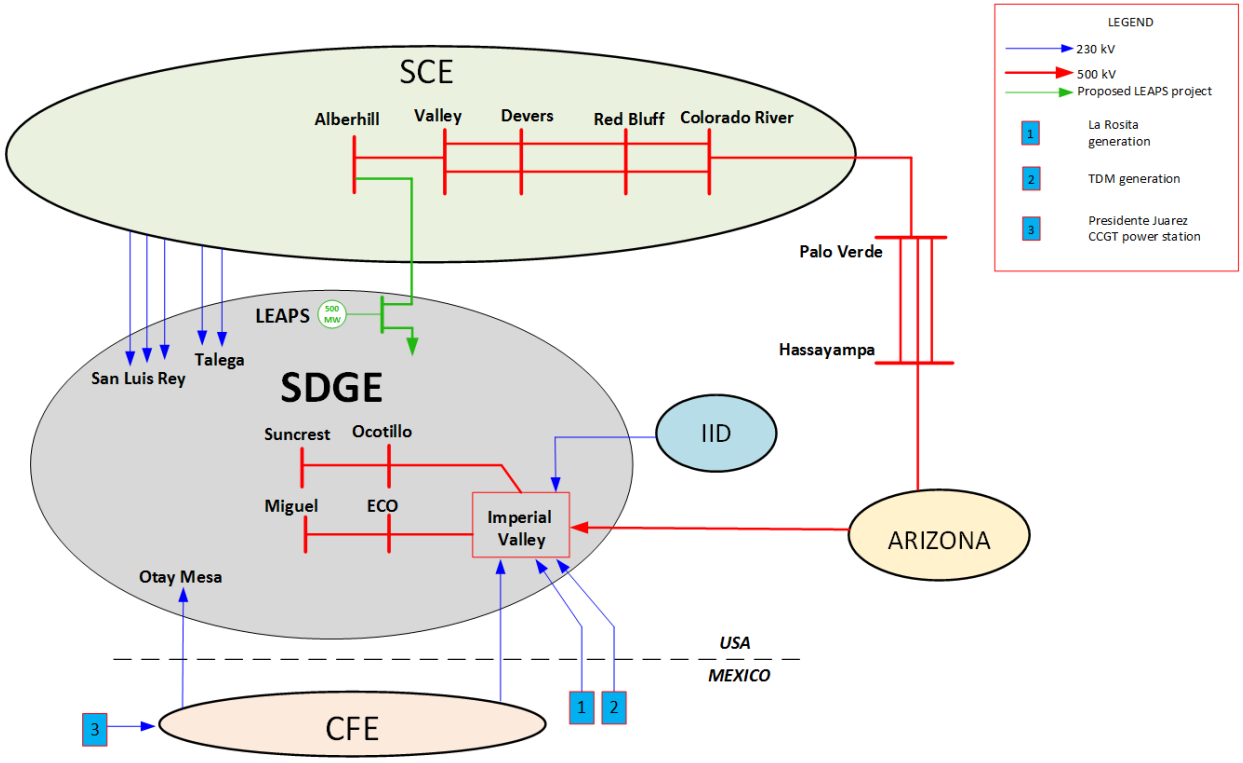
San Diego Gas and Electric (SDGE) is an investor owned utility that provides energy and gas to San Diego and southern Orange Counties, located in Southern California. The SDGE system depends on imports and internal generation to serve its area load. The energy imports are transmitted over 230 kV and 500 kV lines through the following ties:

1. SCE's San Onofre (SONGS) substation:
    A. SONGS-San Luis Rey #1 230 kV line.
    B. SONGS-San Luis Rey #2 230 kV line.
    C. SONGS-San Luis Rey #3 230 kV line.
    D. SONGS-Talega #1 230 kV line.
    E. SONGS-Talega #2 230 kV line.
2. The Southwest Powerlink (SWPL) and Sunrise Powerlink via Imperial Valley substation:
    A. SWPL: North Gila-Imperial Valley-Miguel 500 kV line.
    B. Sunrise Power link: Imperial Valley-Ocotillo-Suncrest 500 kV line.
3. Otay Mesa-Tijuana 230 kV line (from CFE)

Transmission Line Utilization Study

The focus of this power flow analysis is to assess SDGE's major tie-line utilization and to determine how the LEAPS project affects its usage. As shown in the simplified diagram in , SDGE peak load of 4,548 MW is served primarily from a single substation located east of San Diego County at Imperial Valley Substation. The remaining supply is within SDGE loads from gas-fired resources. Since the retirement of SONGS, SDGE imports from SCE has been less than 10%. LEAPS creates a strong (500 kV) connection between two of the three largest load centers in California.[82]

Figure 28. Simplified Diagram of LEAPS Connections to SCE and SDGE Transmission



[82] https://www.ISO.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf, page 29, LA Basin, Bay Area and San Diego represent 41%, 20% and 11% of ISO system peak, respectively.

Case 1- Pre-LEAPS: Prior to adding LEAPS project, the analysis shows that under normal operating conditions (No outages), SDGE is importing 2,911 MW (64% of total SDGE load) from Imperial Valley substation, 379 MW (8% of total load) from SCE, and the rest of the load (28%) is being served by internal SDGE gas fired generation. SDGE is depending on a single substation, Imperial Valley Substation, to serve 64% of its total load, which can cause major reliability issues under severe emergency conditions, like the September 8, 2011 blackout where one of the 500kv line tripped initiating major Blackout[83].

Case 2- LEAPS Transmission Only: After modeling LEAPS transmission project-without LEAPS generation (500 kV connection to SCE and 230 kV connection to SDGE), the topology of the system changed, and it created an additional low impedance path to serve SDGE load. It was shown under normal conditions, Imperial Valley Substation is now serving 60% of SDGE load, SCE is serving 12%, and the remaining 28% is being served by internal SDGE generation. The LEAPS transmission creates a new link between SCE and SDGE that increases the SCE imports by 4% and decreases imports from Imperial Valley Substation by 4%, or approximately 200 MW.

Under normal operating conditions, LEAPS transmission benefits SDGE system by:

- Adding an additional major 500KV tie- line with SCE, and

[83] The outage impacted approximately 2.7 million customers without power. The outages affected parts of Arizona, southern California, and Baja California, Mexico. All of the San Diego area lost power, with nearly 1.5 million customers losing power, some for up to 12 hours. The disturbance occurred near rush hour, on a business day, snarling traffic for hours. Schools and businesses closed, some flights and public transportation were disrupted, water and sewage pumping stations lost power, and beaches were closed due to sewage spills. Millions went without air conditioning on a hot day. *See*: http://www.nerc.com/pa/rrm/ea/Pages/September-2011-Southwest-Blackout-Event.aspx.

- Decreasing the percentage of load being served from a single source (Imperial Valley substation) by approximately 200 MW.

Also, under emergency conditions:

The loss of SDGE's ECO-Miguel 500 kV line with LEAPS transmission only (No generation):

- SDGE load served from Imperial Valley substation is 54% with no LEAPS, compared to 50% with LEAPS transmission.
- SDGE load served from SCE is 22% with no LEAPS, compared to 26% with LEAPS transmission.

The loss of SCE's Valley-Alberhill 500 kV line with LEAPS transmission only (No generation):

- SDGE load served from Imperial Valley substation is 67% with no LEAPS, compared to 64% with LEAPS transmission.
- SDGE load served from SCE is 6% with no LEAPS, compared to 8% with LEAPS transmission.

Case 3- LEAPS Transmission and Generation: The following case contains LEAPS transmission and generation project (500 MW of LEAPS hydro generation was modeled, and 500 MW of SDG&E Gas-fired generation was switched offline to maintain generation-load balance.) The results show that under normal operating conditions, Imperial Valley substation is now serving 56% of total SDGE load, SCE is serving 5% of total SDGE load, the remaining 39% is being served by internal SDGE generation including LEAPS generation.

LEAPS 500 MW generation is serving 11% of total SDGE load under normal operating conditions. In summary, LEAPS transmission and generation benefits:

a. SDGE decrease its imports from Imperial Valley substation by 377 MW compared to the no LEAPS case. This means that LEAPS reduce SDGE reliance on 377 MW of local gas fired resources and could import equal number of renewables using existing transmission capacity that was vacated by LEAPS.

b. SCE decreases exports to SDGE by approximately 134 MW compared to the no LEAPS case. This means that SCE can use the 134 MW to reduce their reliance on local gas-fired generation and import 234 MW of renewables using existing transmission system.

Also, under emergency conditions:

The loss of SDGE's ECO-Miguel 500 kV line with LEAPS transmission and generation:

- SDGE load served from Imperial Valley substation is 54% with no LEAPS, compared to 47% with LEAPS transmission and generation.
- SDGE load served from SCE is 22% with no LEAPS, compared to 18% with LEAPS transmission and generation.

The loss of SCE's Valley-Alberhill 500 kV line with LEAPS transmission and generation:

- SDGE load served from Imperial Valley substation is 67% with no LEAPS, compared to 59% with LEAPS transmission and generation.
- SDGE load served from SCE is 6% with no LEAPS, compared to 2% with LEAPS transmission and generation.

This demonstrates that even under emergency conditions, the LEAPS project benefits both SCE and SDGE systems.

Reliability Analysis

To assess the reliability benefits of LEAPS transmission and generation project, 700 system outages were evaluated to see how the system will react under emergency/severe conditions.

Several contingency files were used to assess the impacts of outages or contingencies associated with the selected base cases. The contingency files, listed below, were run for each of the 3 different case scenarios. The files were adjusted as necessary to accommodate the topology changes for each of the project scenarios (No Project, Proposed LEAPS transmission, Proposed LEAPS transmission and generation).

1. **SDGE-MAIN_P1~P7** (NERC TPL-001-4 based)

   Contains Category P1 (N-1) 500 kV and 230 kV line and transformer outages; adjacent system (SCE – IID) contingencies; selected generator outages; Category C (N-2) stuck breaker, bus, and common structure outages, Sub-System Multiple Terminal line, transformer and generator outages, Orange County outages, N-3 for 69 kV and 138 kV bus outages.

2. **SCE combined outage file (SCE Bulk, SCE East of Lugo, SCE Metro)**

   Contains single and multiple SCE outages for transmission and sub transmission systems. Contains outages for neighboring systems, also major 500/230 kV lines that feed LA Basin load.

3. **CFE and other significant 500 kV lines that connects California to neighboring states.**

The results of the contingency analysis shown below:

Figure 29. Comparison of Results for Single Contingency of Miguel 500/230 kV #1 Pre-LEAPS and Post-LEAPS

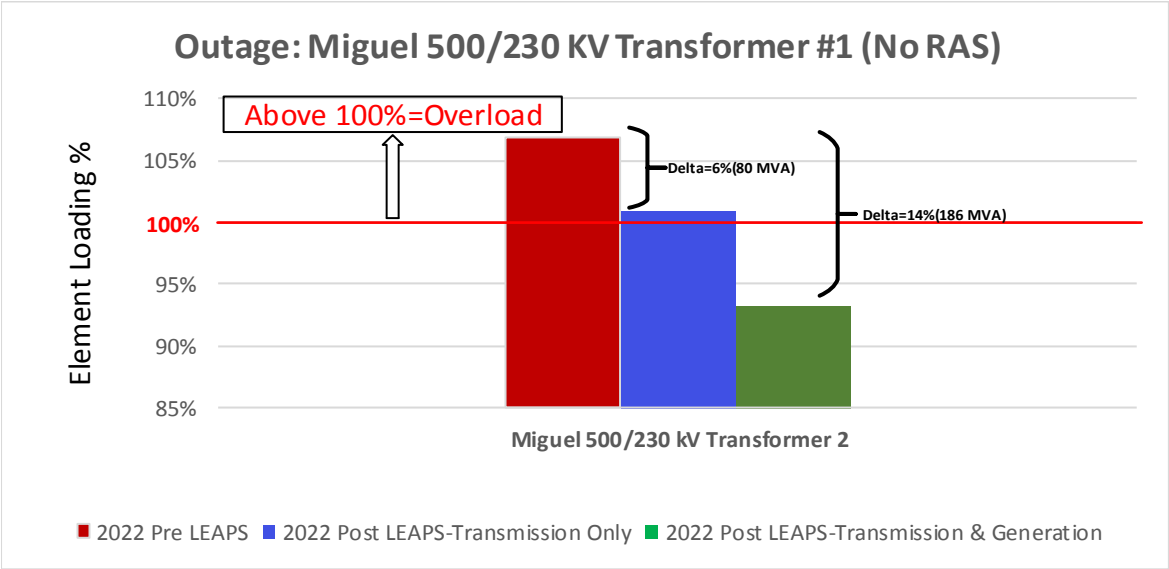


Table 20. Miguel 230/500 kV Transformer #2 Loading following Single Contingency

Transmission Element	Case A- Pre-LEAPS loading (%)	Case B- LEAPS transmission loading (%)	Case C- LEAPS transmission and generation loading (%)	Delta (Case C-A) % / MVA
Miguel 230/500 kV Transformer	107%	101%	93%	14% / 186 MVA

Figure 30. Comparison of Results for Single Contingency of ECO-Miguel 500 kV Line Pre-LEAPS and Post-LEAPS

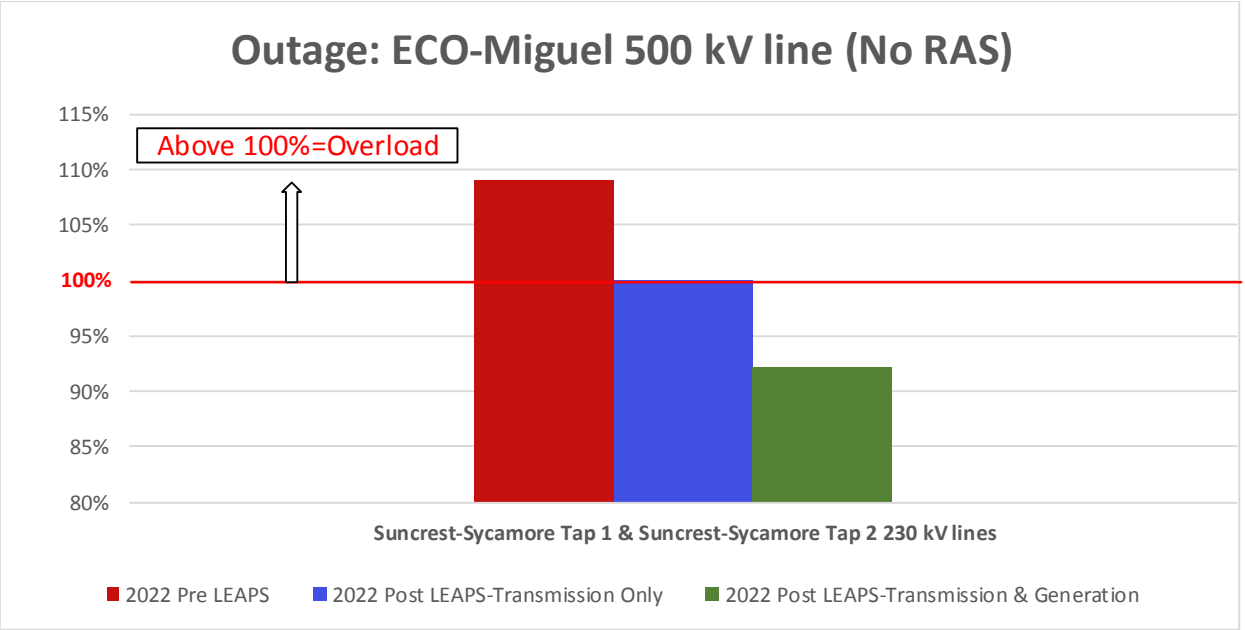


Table 21. Suncrest-Sycamore Tap 230 kV Line Loading following Single Contingency

Transmission Element	Case A- Pre-LEAPS loading (%)	Case B- LEAPS transmission loading (%)	Case C- LEAPS transmission and generation loading (%)	Delta (Case C-A) %/MVA
Suncrest-Sycamore Tap 230 kV	109%	100%	92%	17% / 78 MVA

Figure 31. Comparison of Results for Double Contingency of ECO-Miguel & Suncrest 500 kV line Pre-LEAPS and Post-LEAPS

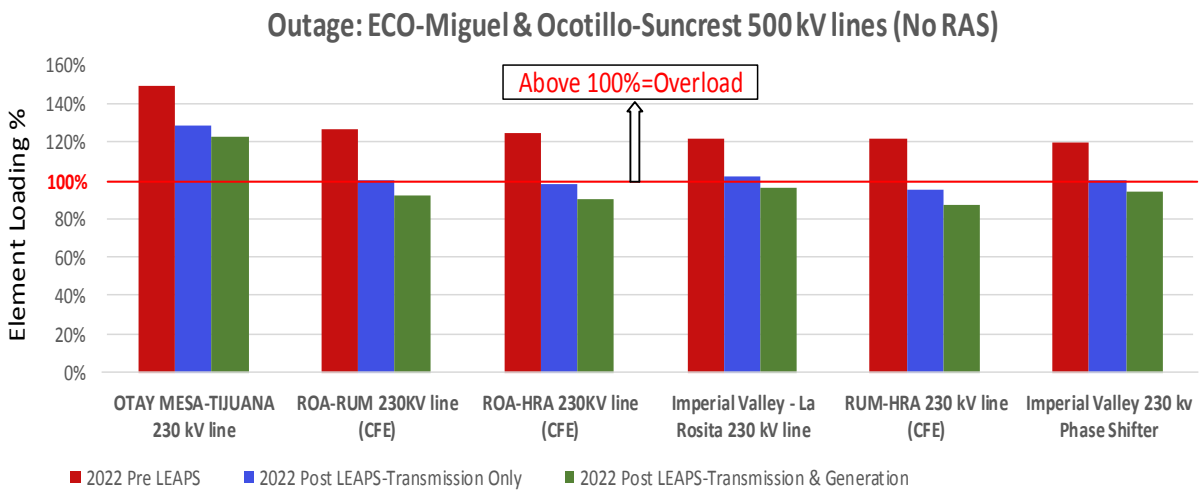


Table 22. Loading of Multiple Elements following Double Contingency of ECO-Miguel & Suncrest 500 kV line

Transmission Element	Case A- Pre-LEAPS loading (%)	Case B- LEAPS transmission loading (%)	Case C- LEAPS transmission and generation loading (%)	Delta (Case C-A) %/MVA
Otay Mesa-Tijuana Tap 230 kV	149%	129%	123%	26% / 221 MVA
Imperial Valley-La Rosita 230 kV	122%	102%	96%	26% / 296 MVA
Imperial Valley 230 kV Phase Shifter	119%	100%	94%	25% / 125 MVA

Figure 32. Comparison of Results for Double Contingency of Ocotillo-Suncrest 500 kV and Imperial Valley-La Rosita 230 kV line Pre-LEAPS and Post-LEAPS

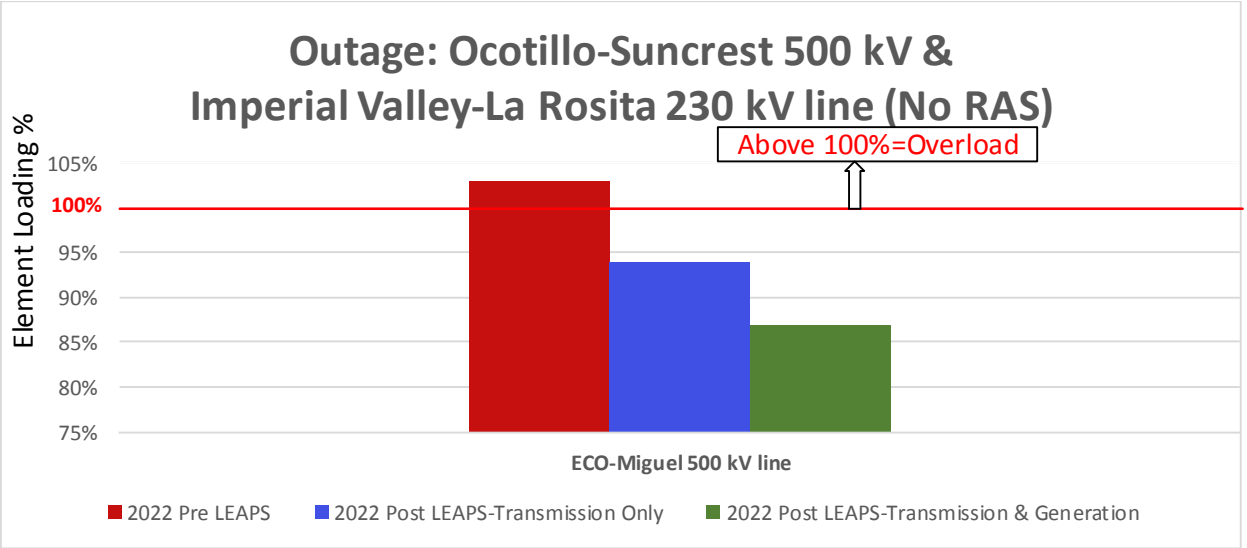


Table 23. Loading of Multiple Elements following Double Contingency of Ocotillo-Suncrest 500 kV and Imperial Valley-La Rosita 230 kV line

Transmission Element	Case A- Pre-LEAPS loading (%)	Case B- LEAPS transmission loading (%)	Case C- LEAPS transmission and generation loading (%)	Delta (Case C-A) %/MVA
ECO-Miguel 500 kV line	103%	94%	87%	16%/416MVA

For all the single and multiple contingencies that were evaluated, LEAPS project did not cause any new thermal or voltage violations on the system. LEAPS project helped decrease and relieve overloads that existed prior to adding LEAPS project.

Although RAS schemes are associated with a lot of the major contingencies that were studied, with modeling the LEAPS project, a RAS scheme to drop generation would not be necessary since the LEAPS project is providing the necessary mitigation to the system under those outages. The reliability assessment that was conducted shows decrease in San Diego and LA Basin Area local capacity requirements that are required to meet the ISO's adverse weather reliability requirement. The assessment shows that the proposed LEAPS project will allow San Diego area

to reliably serve their customers during periods of unusually high energy demand, unexpected outages and abnormal conditions. LEAPS also provide flexibility in operating California's transmission grid, by adding additional import capability to San Diego County from the north, which has limited connectivity to the rest of the ISO grid.

5. EXHIBIT NHC – D

6. LEAPS BENEFITS USING THE CPUC IRP RESOLVE METHODOLOGY

I performed an analysis to quantify the following benefits that LEAPS provides to California consumers:

- Curtailment Risk from Over-generation Benefit
- Production Cost Savings
- Emissions Reduction
- Regulation and Spinning Reserve Cost Savings
- Load Following Benefits
- Local Capacity Requirement Benefits
- Avoided Large Transmission Investments
- Avoided Interconnection Costs
- RPS Cost Savings

7. The LEAPS project will provide benefits in all of the critical areas identified by the CPUC through enhanced reliability and grid resiliency while lowering overall costs to consumers by reducing transmission and generation costs. I have been extremely careful not to duplicate benefits across categories. Based on my calculation of the benefits, I derived a present value estimate of total benefits for LEAPS and compared to its present value cost and find it provides a benefit to cost ratio range of 1.3 to 2.74.

A. Curtailment Risk

I performed an analysis to quantify the curtailment risk benefits that LEAPS provides to California consumers. My analysis utilized production cost modeling, using the CPUC's RESOLVE production cost platform and assumptions to assess the quantity (in MWh) of curtailment risk associated with a 50% RPS generation portfolio sufficient to meet an electric sector emissions target of 42 MMT and 30 MMT respectively for scenarios with and without the LEAPS project.[84] I developed the following four cases to quantify the potential range of curtailment risk benefits:

- CPUC Reference Case 1 ("Case 1") - 42 MMT GHG emissions target, high solar build to meet 50% RPS by 2030,
- CPUC Reference Case 2 ("Case 2") - 42 MMT GHG emissions target, high wind build to meet 50% RPS by 2030,
- CPUC Reference Case 3 ("Case 3") - 30 MMT GHG emissions target, high solar build to meet 50% RPS by 2030, and
- CPUC Reference Case 4 ("Case 4") - 30 MMT GHG emissions target, high wind build to meet 50% RPS by 2030.

8. For each scenario, I ran a "base" production cost simulation run without LEAPS capacity to determine a least-cost renewable portfolio that met or exceeded the GHG and RPS goals. I used this approach to determine an optimal renewable resource procurement plan for three

[84] The RESOLVE model was used to prepare CPUC Staff's recommended Reference System Plan for the 2017-2018 IRP-LTPP. RESOLVE is a capacity expansion model that co-optimizes consumer costs for infrastructure investment and energy dispatch to select optimal resource portfolios that meet the state's GHG targets and other policy objectives such as 50% RPS. A description of the model's input assumptions and other related documentation is located at: http://cpuc.ca.gov/irp/proposedrsp/.

simulation years: 2022, 2026 and 2030. I chose 2022 as the first year because that is when Nevada Hydro anticipates that the LEAPS project will be on-line. I chose 2026 as the second year because that is when the 2200 MW Diablo Canyon nuclear facility is planned for retirement. Finally, I chose 2030 because that is when the State's emissions and RPS policies are to be fully implemented. I developed scenarios for each of the GHG planning targets that optimized for both a high solar (Cases 1 and 3) and high wind (Cases 2 and 4) renewable procurement plan which resulted in the expected curtailment energy shown in **Table 24**.

9. Table 24. Renewable Curtailment Summary without LEAPS

42mmt - Base				
Renewable Curtailment Summary	**Unit**	**2022**	**2026**	**2030**
Case 1	*GWh*	4,678	4,060	7,266
Case 2	*GWh*	3,884	3,516	6,119
30mmt - Base				
Renewable Curtailment Summary	**Unit**	**2022**	**2026**	**2030**
Case 3	*GWh*	6,019	5,055	37,441
Case 4	*GWh*	3,853	3,599	10,292

The level of expected curtailment is notably higher in Cases 1 and 3 compared with Cases 2 and 4 dues to the quantity of solar capacity overbuild needed to satisfy the 50% RPS criteria. Solar capacity output is highest during mid-day and drives a lower net load resulting in higher curtailment energy.

Next, we ran a second set of RESOLVE production cost runs with LEAPS to quantify its benefit for lowering the curtailment energy. With LEAPS, there is lower solar or wind procurement as shown in **Table 25**. For instance, in Case 1, the base case shows a need of 1,141 MW of wind starting 2022 and 9740 MW of new solar starting 2022 and an additional 615 MW in 2030, the Case 1 with LEAPS shows the need for 1,141 MW of wind starting 2022 but 9,467 MW of solar

starting in 2022. LEAPS reduce solar procurement is reduced by 273 MW for years 2022 and 2026, and by 888 MW in 2030 to meet 50% RPS.

Table 25. Lower Procurement Capacity to meet 50% RPS with LEAPS

Case 1			Base			w/LEAPS			Change	
Wind/Solar Capacity	Unit	2022	2026	2030	2022	2026	2030	2022	2026	2030
Wind	*MW*	1,141	1,141	1,141	1,141	1,141	1,141	-	-	-
Solar	*MW*	9,740	9,740	10,355	9,467	9,467	9,467	(273)	(273)	(888)
Case 2			Base			w/LEAPS			Change	
Wind/Solar Capacity	Unit	2022	2026	2030	2022	2026	2030	2022	2026	2030
Wind	*MW*	1,145	1,145	1,904	1,145	1,145	1,328	-	-	(575)
Solar	*MW*	8,841	8,841	8,842	8,841	8,841	8,848	-	-	6
Case 3			Base			w/LEAPS			Change	
Wind/Solar Capacity	Unit	2022	2026	2030	2022	2026	2030	2022	2026	2030
Wind	*MW*	1,141	1,141	4,772	1,141	1,141	4,772	-	-	-
Solar	*MW*	10,977	10,977	23,738	11,229	11,229	19,348	252	252	(4,390)
Case 4			Base			w/LEAPS			Change	
Wind/Solar Capacity	Unit	2022	2026	2030	2022	2026	2030	2022	2026	2030
Wind	*MW*	4,512	4,512	9,585	4,350	4,350	8,901	(162)	(162)	(684)
Solar	*MW*	7,761	7,761	7,761	7,771	7,771	7,771	11	11	11

The lower procurement combined with LEAPS' pump storage availability during mid-day hours to absorb excess variable energy reduces total curtailment energy across all years for all cases. Curtailment reductions for each of the 4 cases are summarized in **Table 26**.[85]

Table 26. Curtailment Reduction Summary with LEAPS

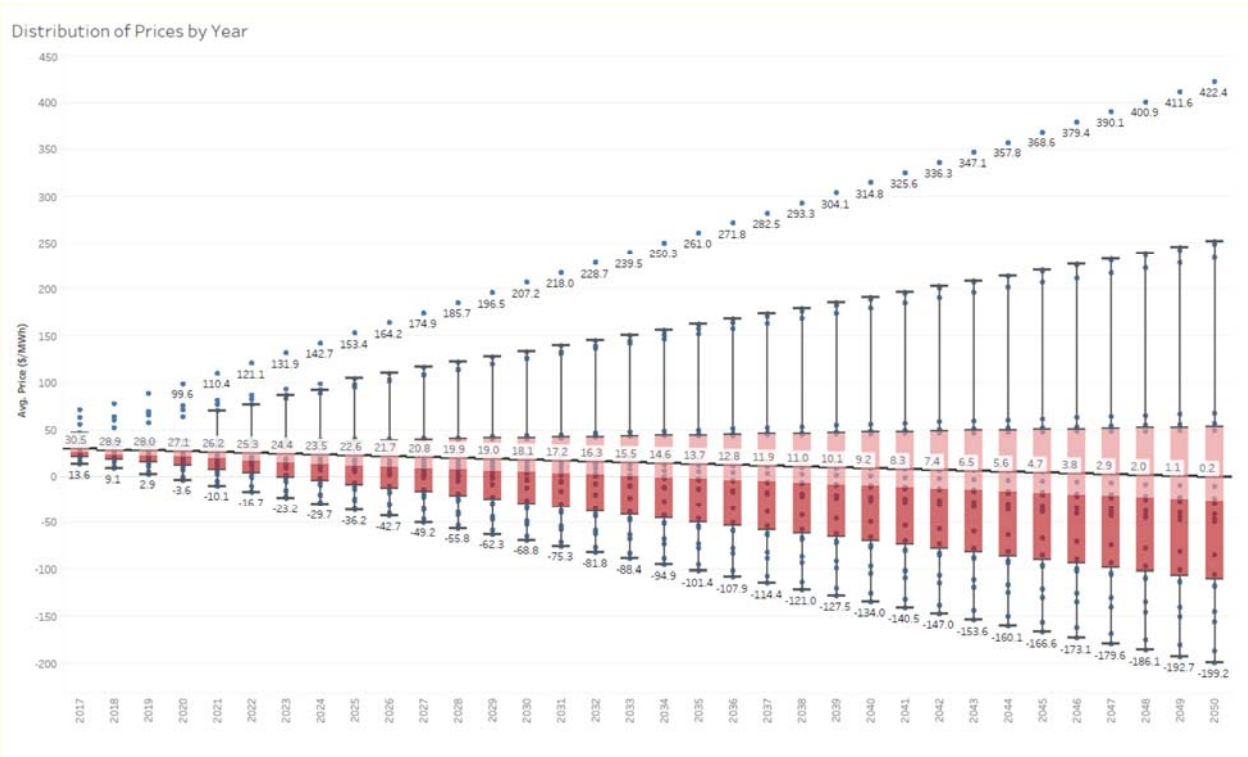
42mmt				
Curtailment Reduction with LEAPS	Unit	2022	2026	2030
Case 1	*GWh*	(768)	(573)	(1,651)
Case 2	*GWh*	(497)	(342)	(957)
30mmt				
Curtailment Reduction with LEAPS	Unit	2022	2026	2030
Case 3	*GWh*	(410)	(412)	(11,254)
Case 4	*GWh*	(480)	(326)	(1,373)

LEAPS is able to pump 600 MW for 12 hours 360 days/yr. with a round trip efficiency of 83%. This translate to a total pumping capability of 2,152 GWH annually.

[85] Case 3 resulted in curtailment benefit in excess of maximum annual LEAPS pumping energy. For the benefit calculation, we have capped the annual GWh benefit at 2500 GWh.

The potential $/MWh cost of curtailment energy to consumers is based on a projection of the average hourly real-time 5-minute marginal cost of energy (MCE) expected over the life of the project. Using historic average hourly real-time MCEs obtained from CAISO from 2015, 2016 and 2017, I projected out average hourly prices for 2018 through 2050 based on the linear price trend obtained from the historic data. The distribution of these hourly projected prices is shown in **Figure 33** which shows the range of hourly forecasted CAISO MCE price in $/MWh along with the maximum, minimum, and average price.

10. Figure 33. Distribution of Projected Hourly MCEs



In the CAISO markets, negative MCEs are indicative of over-generation or oversupply conditions. To calculate the annual curtailment benefit over the life of the project, I computed the <u>hourly</u> pumping revenue by distributing the curtailment reduction energy over the hours with expected negative MCEs, considering LEAPS's maximum pumping capability. The annual

benefits are provided graphically in **Figure 34** and the resulting annual levelized benefits for each of the Cases are provided in **Table 27**.

Figure 34. Annual Curtailment Benefit

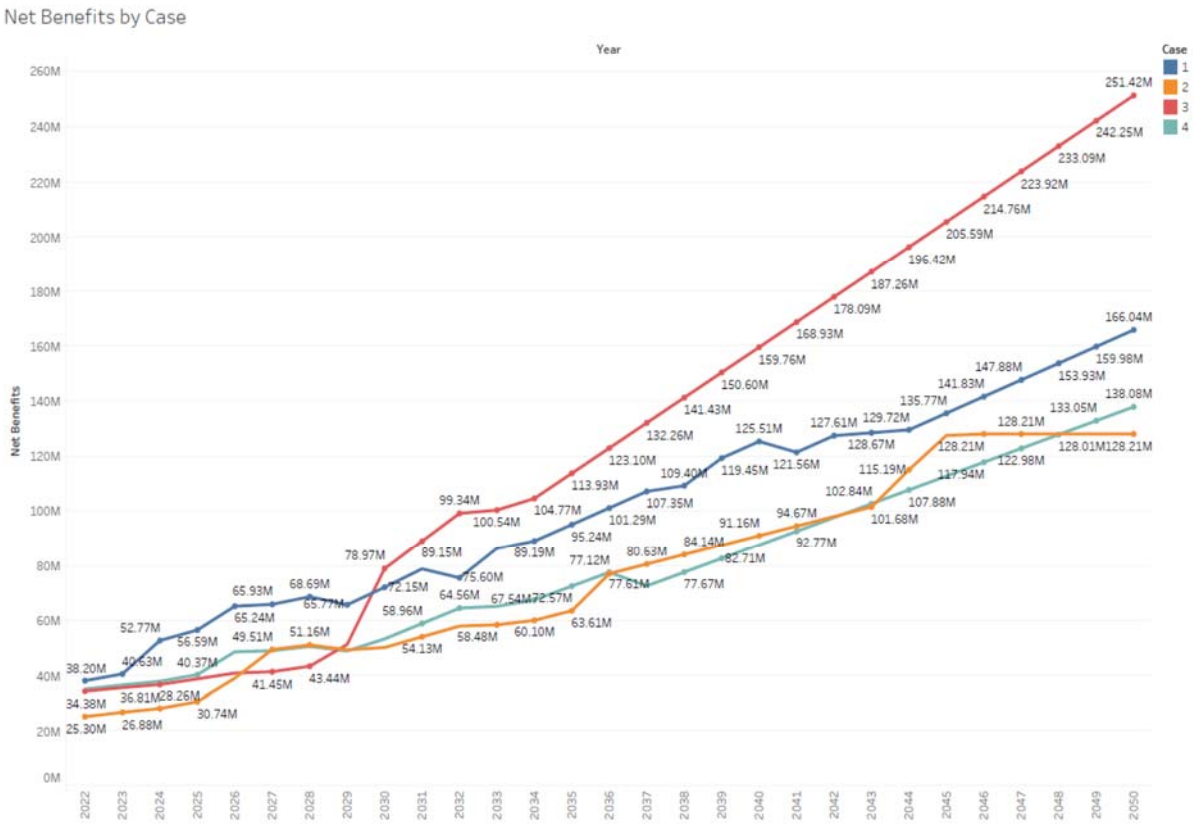


Table 27. Levelized Annual Curtailment Benefit with LEAPS.

Levelized Annual Benefits ($)	**42mmt**		**30mmt**	
	Case 1	Case 2	Case 3	Case 4
Curtailment Benefit	$128,280,745	$98,729,512	$179,965,951	$103,639,516

LEAPS is able to save the ratepayers $98.7 million to $179.9 million in costs that otherwise will be paid to generators for over-generation.

B. Production Cost Benefits

The LEAPS project provides energy cost benefits to consumers with its ability to displace or facilitate redispatch ISO generation more economically. I utilized the production cost analysis described in the previous sections to quantify the energy cost savings with LEAPS. The energy cost is calculated as the sum of the variable operating costs, fuel costs, start-up and shutdown costs of the dispatched resources in the cases. The cost difference between the without and with LEAPS case is the energy cost savings to consumers where a positive dollar amount is a benefit and a negative dollar amount is the incremental cost to consumers with LEAPS. My analysis shown in Table 28, below, that LEAPS would result in annual benefits to consumers ranging from -$17 million in Case 2 in 2030 to $143 million in Case 3 in 2026. The energy cost savings is primarily due to savings in fuel and variable operating costs of natural gas-fired resources. LEAPS contributes to the redispatch of those resources as shown in Table 29. Gas-fired resource production is reduced as high as 15,459 GWh in 2030 for Case 1. In Case 3, the main driver is lower marginal pricing as the energy output increased by 182 GWh yet the system still realized a benefit of $21 million in 2030.

Table 28. Production Cost Savings due to LEAPS.

		Base			w/LEAPS			Benefit		
Production Cost	**Unit**	**2022**	**2026**	**2030**	**2022**	**2026**	**2030**	**2022**	**2026**	**2030**
Case 1	*$MM*	$3,285	$4,118	$5,146	$3,233	$4,048	$5,033	$52	$70	$113
Case 2	*$MM*	$3,361	$4,203	$5,175	$3,280	$4,102	$5,192	$80	$101	$(17)
Case 3	*$MM*	$3,191	$4,257	$4,304	$3,089	$4,115	$4,283	$102	$143	$21
Case 4	*$MM*	$3,041	$3,993	$4,045	$2,970	$3,927	$4,015	$71	$66	$31

11.

Table 29. Energy Output of Natural Gas Fired Units

		Base			w/LEAPS			Change		
Natural Gas Energy	Unit	2022	2026	2030	2022	2026	2030	2022	2026	2030
Case 1	*GWh*	40,171	55,817	65,285	36,292	55,096	49,826	(3,880)	(721)	(15,459)
Case 2	*GWh*	42,048	57,838	65,908	40,990	56,473	66,541	(1,058)	(1,365)	633
Case 3	*GWh*	37,840	57,083	49,644	36,292	55,096	49,826	(1,549)	(1,987)	182
Case 4	*GWh*	36,261	54,042	46,872	35,309	53,322	46,773	(953)	(720)	(99)

The production cost benefits for the three study years are used to calculate annual levelized production cost benefits over the life of the project. I estimate those savings to range between $200,000 and $104.7 million. (**Table 30**)

Table 30. Levelized Annual Avoided RPS Fixed Cost Benefit due to LEAPS

Levelized Annual Benefits ($)	42mmt		30mmt	
	Case 1	Case 2	Case 3	Case 4
Production Cost Savings	$104,680,000	$200,000	$37,240,000	$37,000,000

C. Emissions Benefits

The production cost scenarios optimized the portfolios to ensure meeting either a 42mmt or 30mmt carbon emission target for the electric utility sectors. A comparison of the emissions output shows LEAPS can help meet those targets with lower overall emissions as shown in Table 31.

Table 31. Emissions Benefits due to LEAPS

		Base			w/LEAPS			Change		
Emissions Summary	Unit	022	026	030	022	026	030	022	026	030
Case 1	*MMtCO2*	1	7	0	1	6	9	0.2)	0.3)	0.6)
Case 2	*MMtCO2*	2	7	0	1	7	0	0.4)	0.5)	.2
Case 3	*MMtCO2*	0	7	4	9	6	4	0.6)	0.7)	.0
Case 4	*MMtCO2*	0	6	3	9	6	3	0.4)	0.3)	0.1)

Based on $23.27/m-ton price,[86] the emissions benefits due to LEAPS are shown in Table 32.

Table 32. Emissions Cost Savings due to LEAPS

Levelized Annual Benefits ($)	42mmt		30mmt	
	Case 1	Case 2	Case 3	Case 4
Emission Cost Savings	$12,658,880	-$2,233,920	$2,420,080	$3,257,800

D. Regulation and Spinning Reserve Benefits

The production cost study results, using the CPUC RESOLVE model, also optimized LEAPS' capabilities to provide regulation and spinning reserve capacity to the ISO. My study shows that LEAPS can provide between 266 GW and 386 GW of regulation capacity annually, and between 442 GW and 565 GW of spinning reserve capacity annually as summarized in *and , respectively. The three-year average historic regulation and* spinning reserve clearing prices from ISO were $10.20/MWh and $6.81/MWh, respectively. Using these prices, I calculate the levelized annual benefits for regulation service to be between $2.85 million and $3.38 million, and for spinning reserves to be between $3.3 million and $3.8 million (Table 35.)

[86] http://www.caiso.com/Documents/BulkEnergyStorageResource-2015-2016SpecialStudyUpdatedfrom40to50Percent.pdf at page 25.

Table 33. Annual Regulation for LEAPS

Annual		LEAPS		
Regulation	Unit	2022	2026	2030
Case 1	*MW*	374,947	304,441	329,253
	#hours	5,742	4,805	5,288
Case 2	*MW*	386,187	321,123	314,151
	#hours	5,776	5,041	4,617
Case 3	*MW*	356,368	312,377	277,468
	#hours	5,532	4,699	4,546
Case 4	*MW*	362,165	332,678	266,574
	#hours	5,542	4,970	4,262

Table 34. Annual Spin Capacity for LEAPS

Annual		LEAPS		
Spin	Unit	2022	2026	2030
Case 1	*MW*	555,296	539,458	491,905
	#hours	4,406	4,264	3,912
Case 2	*MW*	538,876	486,409	561,544
	#hours	4,269	3,825	4,373
Case 3	*MW*	442,752	477,546	489,416
	#hours	3,720	3,885	3,660
Case 4	*MW*	511,095	497,099	565,036
	#hours	4,005	3,971	4,199

Table 35. Levelized Annual Regulation and Spin Reserve Benefit for LEAPS

Levelized Annual Benefits ($)	42mmt		30mmt	
	Case 1	Case 2	Case 3	Case 4
Regulation	$3,375,425	$3,268,808	$2,923,042	$2,851,000
Spinning Reserve	$3,410,317	$3,770,832	$3,301,036	$3,781,497

E. Load Following Benefits

LEAPS has tremendous flexibility to provide load following to the grid in an era of increased intermittent resources and less reliance on gas plants. A fast-moving resource such as LEAPS is critical from an operation and reliability perspectives. I used the results of the production cost scenarios described in Section A to quantify the hourly load following capacity (MW) provided by LEAPS in each study year. LEAPS capacity is used for both load following up and down for over 7000 hours annually in most of cases. **Table 36**is a summary of the capacity used. The load following benefit from LEAPS is valued at the net avoided cost to use LEAPS instead of other more expensive units for load following. I have calculated an avoided cost of the three-year historic average (RT 5-min) LMP at ISO pricing node SP15 of $30.16/MWh. This translates to a range of $58.7 million to $65.4 million levelized annual benefit for load following (**Table 37**.)

Table 36. Annual Load Following Capacity for LEAPS

Annual		LEAPS		
Load Following	Unit	2022	2026	2030
Case 1	*MW*	1,646,175	1,734,944	2,259,051
	#hours	7,332	7,079	7,437
Case 2	*MW*	1,587,572	1,760,389	2,200,403
	#hours	7,300	7,385	7,394
Case 3	*MW*	1,756,906	1,874,607	2,047,482
	#hours	7,478	7,096	6,915
Case 4	*MW*	1,557,893	1,752,731	2,000,720
	#hours	7,077	7,162	7,023

Table 37. Levelized Annual Load Following Benefit

Levelized Annual Benefits ($)	42mmt		30mmt	
	Case 1	Case 2	Case 3	Case 4
Load Following Benefit	$65,389,674	$63,823,854	$60,633,833	$58,674,927

F. Local Capacity Requirement Benefits

I ran power flow analyses to determine LEAPS benefits for satisfying LCR needs. Per my analysis, adding LEAPS benefits both SCE and SDGE areas. Adding LEAPS decreases import flow from Imperial Valley substation by 377 MW compared to a no LEAPS case, and decreases import flow from SCE by approximately 134 MW compared to a no LEAPS case. This means that SCE and SDGE will be able to reduce their reliance on high cost local gas-fired generation to satisfy its LCR. Exhibit NHC-C provides further details regarding the assumptions, study approach and results of my power flow analysis.

A. My assessment shows that the proposed LEAPS project will allow San Diego area to reliably serve their customers during periods of unusually high energy demand, unexpected outages and abnormal conditions. LEAPS also provide flexibility in operating California's transmission grid, by adding additional import capability to San Diego County from the north, which has limited connectivity to the rest of the CAISO grid. In summary, my analysis demonstrates that LEAPS provides consumer benefits as an LCR resource and transmission reliability project. The value of the LCR capacity benefit is $75.68 kw-yr.[87] based on 500 MW generation, this results in an annual benefit of $38 million.

[87] https://www.CAISO.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf. Section 10.8 and the soft offer cap basis was established as the sum of mid-cost results for insurance, ad valorem, and fixed operation and maintenance costs included in the CEC's draft staff report *Estimated Cost of New Renewable and Fossil Generation in California*: http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SD.pdf. The levelized fixed cost target presented in DMM's analysis of net market revenues for new gas-fired generation in Chapter 1 is based on the same report, but includes financing and taxes.

G. Avoided Interconnection Costs

As shown in Section I, LEAPS reduces the renewable capacity needed to achieve the 50% RPS goal. For instance, under Case 1, using the PUC RESOLVE model, LEAPS can avoid capital investment of 273 MW to 888 MW of solar capacity from 2022 to 2030. The avoided renewable capital cost also has an avoided transmission interconnection cost. The avoided transmission interconnection cost is based on the reduced renewable capacity to meet the state's 50% RPS goal with LEAPS in service multiplied by a price of $22/kW-yr.[88]. The reduced capacity for each of the production cost scenarios reference cases is provided in **Table 40**. The resulting levelized annual benefits are shown in **Table 38** for each of the scenarios. I estimate the avoided transmission interconnection cost to range between $13 million and $80 million annually.

Table 38. Levelized Annual Avoided Interconnection Cost Benefit due to LEAPS

Levelized Annual Benefits ($)	42mmt		30mmt	
	Case 1	Case 2	Case 3	Case 4
Avoided Interconnection Cost	$17,371,200	$10,515,120	$80,240,160	$12,987,040

H. Avoided Large Transmission Investments

Under Cases 2 and 4, with high wind penetration, new transmission projects will need to be built to interconnect new wind capacity to meet California's RPS and emissions goals. The analysis shows that under Case 2 and 4, LEAPS could reduce procurement of wind by 569 MW and 684 MW respectively (**Table 40**), thus the fixed costs for new transmission lines in the relevant areas will be avoided. Based on the utilized PUC RESOLVE assumptions, the avoided transmission

[88] http://www.caiso.com/Documents/BulkEnergyStorageResource-2015-2016SpecialStudyUpdatedfrom40to50Percent.pdf at page 17.

costs occurred in the Greater Carrizo and in the Northern California transmission zones for Case 2 and Case 4 at a cost of $89/kW-yr. and $52/kW-yr. respectively in year 2030. The resulting annual levelized benefit for LEAPS ranges between $29.9 and $43 million as shown in **Table 39**.

Table 39. Levelized Annual Avoided Large Transmission Cost Benefit due to LEAPS

Levelized Annual Benefits ($)	**42mmt**		**30mmt**	
	Case 1	Case 2	Case 3	Case 4
Avoided Large Transmission Investment	$0	$42,987,000	$0	$29,877,120

I. RPS Cost Savings

LEAPS will reduce the quantity of additional renewable capacity needed to achieve the state's 50% RPS goal. This benefits California consumers by reducing the cost of reaching renewable energy targets because the LEAPS project facilitates the integration of lower cost renewable resources located in remote areas, or reduces solar and wind over-build as shown in **Table 40**. Using the results of the same production cost scenarios described in Section A above, I quantified the consumer savings realized by LEAPS based on the avoided fixed cost of new renewable generation that would not be needed to meet the 50% RPS target when LEAPS is on-line. The change of renewable portfolio capacity due to LEAPS is shown in **Table 40**, below. The renewable generating capacity reduction in year 2030 ranges from 569 MW to 4,390 MW, given the assumptions of the 4 cases. I used the CPUC RESOLVE model to develop optimized portfolios both with and without LEAPS for each of the three study years: 2022, 2026, and 2030. Additional ("new") renewable capacity is selected by the RESOLVE optimization to achieve 50% RPS and California's emissions target by 2030. The selected generating resources include new in-state or out-of-state geothermal, biomass, solar or wind resources beyond the model's baseline resource assumptions. The baseline resources include ISO's existing resources, adjusted for

planned retirements, renewable resources likely to be constructed based on prior CPUC approval, 1,325 MW of mandated energy storage capacity as well as achievement of demand-side energy efficiency programs.

Table 40. Comparison of Renewable Procurement Plan to Meet State RPS Goals with and without LEAPS

		Base			w/LEAPS			Change		
Renewable Procurement	**Unit**	**2022**	**2026**	**2030**	**2022**	**2026**	**2030**	**2022**	**2026**	**2030**
Case 1	*MW*	10,881	10,881	11,748	10,608	10,608	10,860	(273)	(273)	(888)
Case 2	*MW*	9,985	9,985	10,998	9,985	9,985	10,429	-	-	(569)
Case 3	*MW*	12,118	12,118	30,889	12,370	12,370	26,499	252	252	(4,390)
Case 4	*MW*	12,272	12,272	19,724	12,121	12,121	19,050	(151)	(151)	(674)

The difference between the RPS portfolio's fixed procurement cost without and with LEAPS quantifies the net benefit where a positive dollar amount represents a benefit to consumers and a negative dollar amount means consumers do not benefit from LEAPS. My analysis shows that the reduced capacity procurement due to LEAPS results in an annual RPS benefit that ranges from $111 to $637 million dollars in 2030 (**Table 41**).[89]

Table 41. Annual RPS Benefit due to LEAPS

		Base			w/LEAPS			Benefit (Excluding TX costs))		
New Renewables Fixed Cost	**Unit**	**2022**	**2026**	**2030**	**2022**	**2026**	**2030**	**2022**	**2026**	**2030**
Case 1	*$MM*	$1,472	$1,472	$1,735	$1,435	$1,435	$1,592	$ 31	$ 31	$ 123
Case 2	*$MM*	$1,351	$1,351	$1,673	$1,351	$1,351	$1,549	$ -	$ -	$ 111
Case 3	*$MM*	$1,639	$1,639	$6,334	$1,673	$1,673	$5,599	$(28)	$(28)	$637
Case 4	*$MM*	$1,777	$1,777	$4,628	$1,751	$1,751	$4,455	$ 22	$ 22	$ 158

[89] All costs expressed in 2016 dollars.

Table 42 and **Table 43** show the locational RPS portfolio mix for Case 1 with and without LEAPS and the difference in fixed costs for the two RPS portfolios. The LEAPS project reduces the need to procure solar capacity in the Riverside East area by 273 MW in years 2022 and 2026, and by 888 MW in 2030 resulting in an annual cost savings of $31 million in years 2022 and 2026, and $123 million in year 2030.

Table 42. Comparison of RPS Procurement without and with LEAPS for Case 1.

Renewable Resource Build by Location (MW)		Base			w/LEAPS			Change		
RESOLVE Resource	Tx Zone	022	026	030	022	026	030	022	026	030
Northern California_ Solar	*Northern California*									
Solano_Solar										
Central_Valley_North _Los_Banos_Solar										
Westlands_Solar										
Greater_Carrizo_Solar										
Tehachapi_Solar	*Tehachapi*	,013	,013	,013	,013	,013	,013			
Kramer_Inyokern_ Solar	*Kramer_Inyokern*	,981	,981	,981	,981	,981	,981			
Mountain_Pass_El_ Dorado_Solar										
Southern_California_ Desert_Solar										
Riverside_East_Palm_ Springs_Solar	*Riverside_East_ Palm_Springs*	,740	,740	,355	,467	,467	,467	273)	273)	888)
Greater_Imperial_ Solar										
Distributed_Solar										
Baja_California_Solar										
Utah_Solar										
Southern_Nevada_ Solar	*Mountain_Pass_El_ Dorado*	,006	,006	,006	,006	,006	,006			
Arizona_Solar										
New_Mexico_Solar										
Northern_California_ Wind										
Solano_Wind	*Solano*	43	43	43	43	43	43			
Central_Valley_North _Los_Banos_Wind	*Central_Valley_ North_Los_Banos*	46	46	46	46	46	46			
Greater_Carrizo_ Wind	*Greater Carrizo*	60	60	60	60	60	60			

Renewable Resource Build by Location (MW)		Base			w/LEAPS			Change		
RESOLVE Resource	Tx Zone	022	026	030	022	026	030	022	026	030
Tehachapi_Wind	*Tehachapi*	49	49	49	49	49	49			
Kramer_Inyokern_ Wind										
Southern_California_ Desert_Wind										
Riverside_East_Palm_ Springs_Wind	*Riverside East_ Palm_Springs*	2	2	2	2	2	2			
Greater_Imperial_ Wind										
Distributed_Wind										
Baja_California_Wind										
Pacific_Northwest_ Wind										
NW_Ext_Tx_Wind										
Idaho Wind										
Utah_Wind										
Wyoming_Wind										
Southern Nevada_ Wind										
Arizona_Wind										
New_Mexico_Wind										
SW_Ext_Tx_Wind										
InState_Biomass										
Greater_Imperial_ Geothermal										
Northern California_ Geothermal	*Northern California*			53			53			
Pacific Northwest_ Geothermal										
Southern Nevada_ Geothermal										
In-State		,875	,875	,742	,602	,602	,854	273)	273)	888)
Out-Of-State		,006	,006	,006	,006	,006	,006			

Table 43. RPS Fixed Cost Benefit for Case 1.

CA RPS Fixed Costs by Technology		Base			w/LEAPS			Change		
Technology	Unit	022	026	030	022	026	030	022	026	030
Geothermal	*$MM*	-	-	157	-	-	157	-	-	-
Biomass	*$MM*	-	-	-	-	-	-	-	-	-

CA RPS Fixed Costs by Technology		Base			w/LEAPS			Change		
Technology	Unit	022	026	030	022	026	030	022	026	030
Wind	*$MM*	183	183	183	183	183	183	-	-	-
Solar	*$MM*	1,289	1,289	1,395	1,252	1,252	1,252	37	37	143
Total	*$MM*	1,472	1,472	1,735	1,435	1,435	1,592	37	37	143

The avoided renewable fixed costs include the associated interconnection costs discussed in Section G. Thus, for purposes of quantifying the net RPS Fixed Cost benefit due to LEAPS I have subtracted out the interconnection avoided costs from the RPS Fixed Cost totals shown in **Table 41**. The resulting levelized annual RPS fixed cost benefit ranges between $93.6 million and $530.8 million as shown in **Table 44**.

Table 44. Levelized Annual Avoided RPS Fixed Cost Benefit due to LEAPS (excluding transmission costs)

Levelized Annual Benefits ($)	42mmt		30mmt	
	Case 1	Case 2	Case 3	Case 4
Reduced Cost of Renewables (RPS)	$108,668,800	$93,644,880	$530,879,840	$136,492,960

J. Summary of Benefits

For each of the quantifiable benefits, I calculated a hypothetical levelized annual benefit over the estimated [50-year life] of the project and divided this amount by the levelized annual cost of the project for each of the four reference cases used for my analysis. I used the depreciation assumption in the CPUC RESOLVE model for purposes of this analysis. It is important to note that the actual revenue requirement for the LEAPS project will likely differ based on FERC's determination of the just and reasonable rate, including the award of incentives that are appropriate for the LEAPS project. Table 45 summarizes the benefits of each of the categories

and provides the resulting benefit-to-cost ratio for LEAPS under the four cases. The range of benefit-to-costs for LEAPS is from 1.53 to 3.8:

Table 45. LEAPS Benefits to Cost Ratio for the 4 Reference Cases Analyzed

	Scenarios	**42 mmt Scenario**		**30 mmt Scenario**	
Benefit #	Levelized Annual Benefits	CPUC Reference Case 1	CPUC Reference Case 2	CPUC Reference Case 3	CPUC Reference Case 4
1	*Over-generation/ Curtailment Benefit*	$128,280,745	$98,729,512	$179,965,951	$103,639,516
2	*Grid Resiliency (Electric Reliability Services)*	$30,000,000	$30,000,000	$30,000,000	$30,000,000
3	*Load Following Savings*	$65,389,674	$63,823,854	$60,633,833	$58,674,927
4	*Regulation*	$3,375,425	$3,268,808	$2,923,042	$2,851,000
5	*Spinning Reserve*	$3,410,317	$3,770,832	$3,301,036	$3,781,497
6	*Transmission Interconnection Cost*	$17,371,200	$10,515,120	$80,240,160	$12,987,040
7	*Local Transmission (LCR) Savings*	$37,840,000	$37,840,000	$37,840,000	$37,840,000
8	*Avoided Large Transmission Investment*	$0	$42,987,000	$0	$29,877,120
9	*Reduced Cost of Renewables (RPS)*	$108,668,800	$93,644,880	$530,879,840	$136,492,960
10	*Production Cost Savings*	$104,680,000	$200,000	$37,240,000	$37,000,000
11	*Emission Cost Savings*	$12,658,880	$2,233,920	$2,420,080	$3,257,800
Levelized Annual Benefits		$511,675,040	$382,546,086	$965,443,942	$456,401,859
Levelized Annual Costs		$249,852,456	$249,852,456	$249,852,456	$249,852,456
Benefits to Cost Ratio (BCR)		2.05	1.53	3.864	1.827

Figure 35. Levelized Project Benefits Per Benefit Category

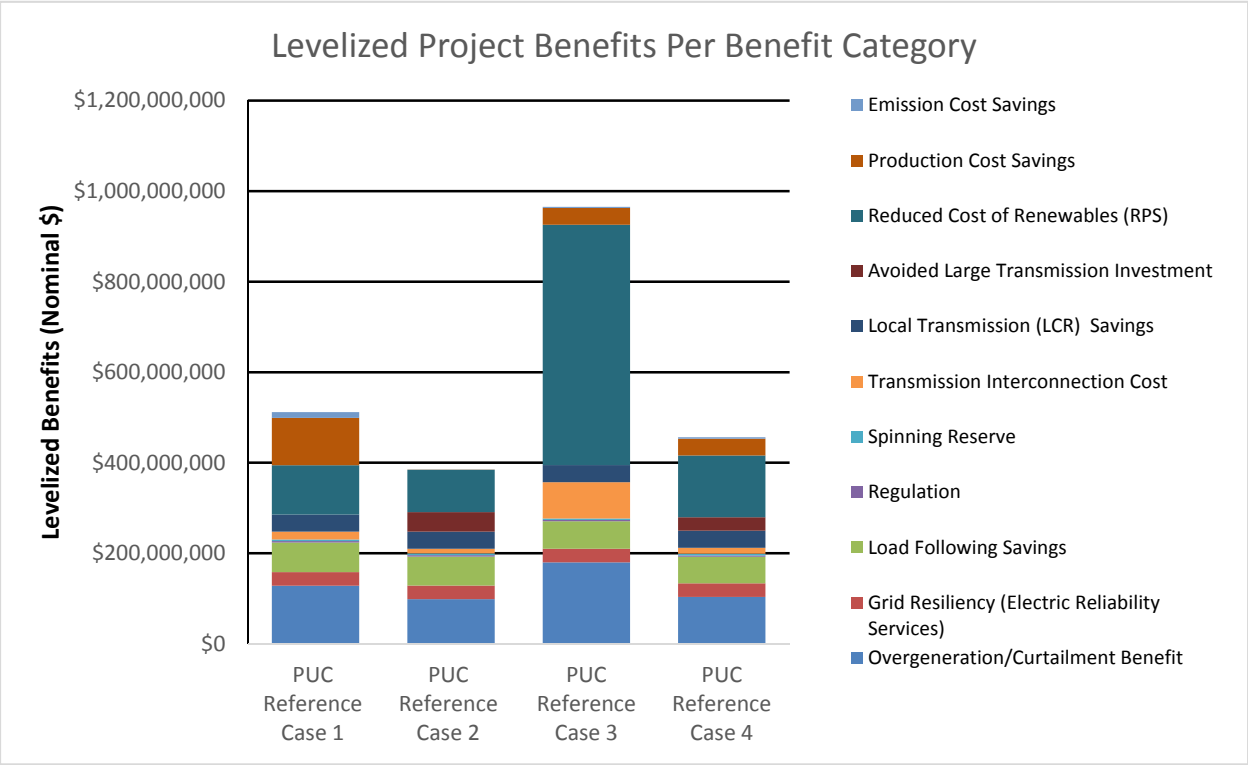
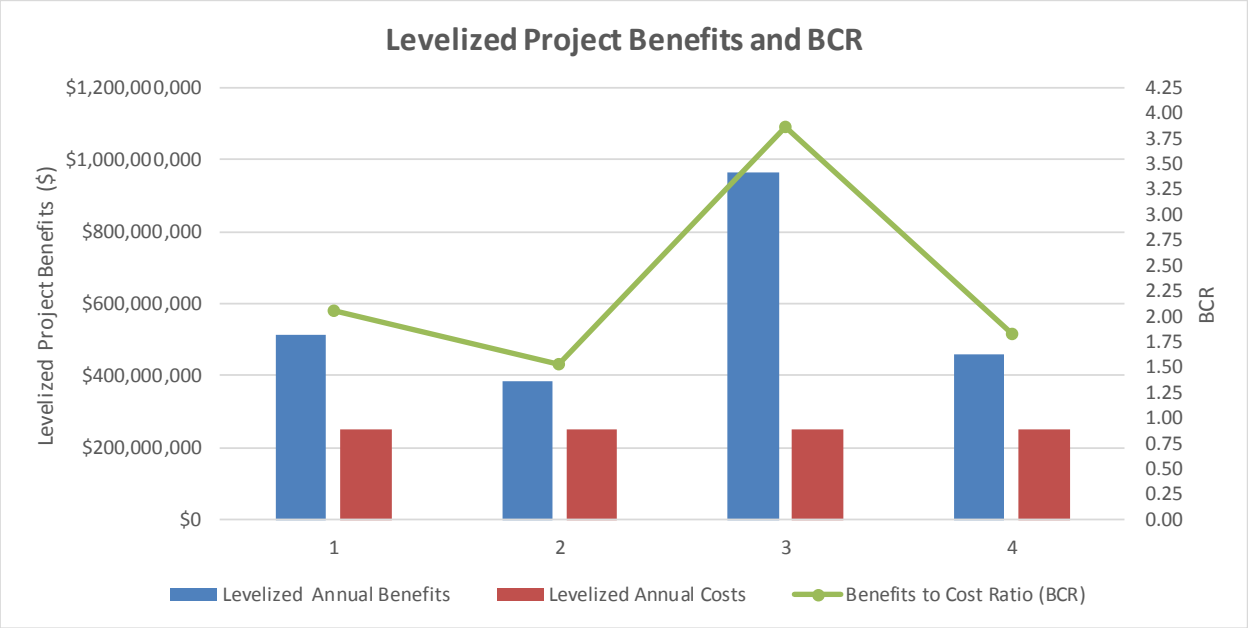


Figure 36. Levelized Project Benefits and BCR



As a final step I calculated the present value benefits and benefit to cost ratio. I have provided a summary in Table 46 below.

Table 46. NPV and Benefits-to-Cost Ratio for LEAPS for the 4 Reference Cases

Scenarios	42 mmt Scenario		30 mmt Scenario	
Present Value	**PUC Reference Case 1**	**PUC Reference Case 2**	**PUC Reference Case 3**	**PUC Reference Case 4**
NPV of all Benefits at WACC	$5,126,458,788	$4,034,307,077	$8,480,725,326	$4,647,764,023
Project Costs at WACC	$3,092,957,029	$3,092,957,029	$3,092,957,029	$3,092,957,029
Benefits to Cost Ratio (BCR)	1.66	1.30	2.74	1.50

Figure 37. Levelized Project Benefits Per Benefit Category

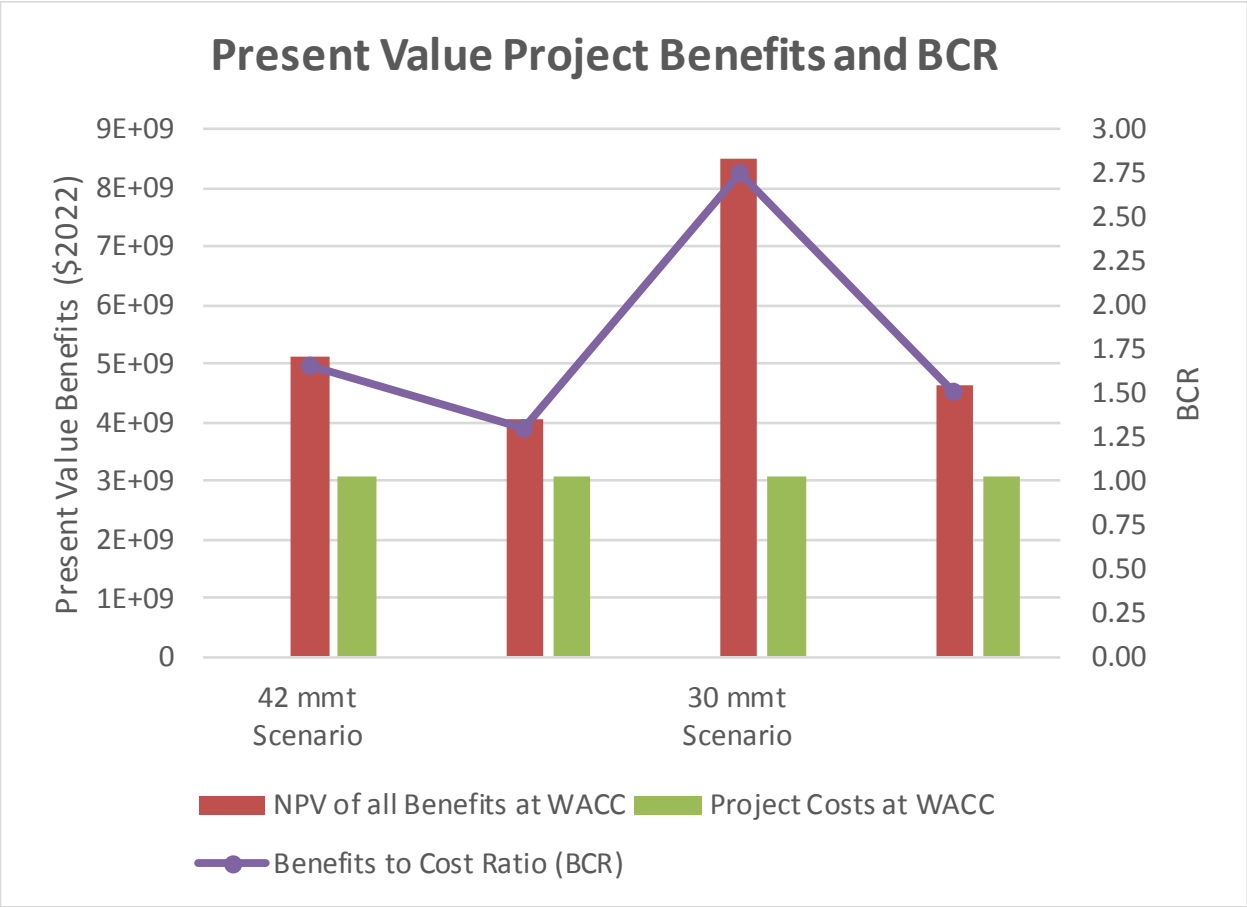


EXHIBIT NHC- E

ZIAD ALAYWAN P.E. TESTIMONY AND PUBLICATIONS

FEDERAL ENERGY REGULATORY COMMISSION AND FEDERAL COURTS

1. Design of California Real-Time Energy and Ancillary Services Markets, Testimony by Alaywan, Z.; Docket No. ER98-2843-009, November 16, 1998.

2. Introducing the Firm Transmission Rights Market under Amendment No. 9 of the CAISO Tariff; Testimony by Alaywan, Z.; Docket No. ER 98-3594-001. 1998.

3. Introducing the Downward Regulation Bids design under Amendment No. 11 of the CAISO Tariff, Testimony by Alaywan, Z.; Dockets No EC96-19-039; ER96-1663-040.1999.

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5. Introducing the Intra Zonal Congestion Management under Amendment No.18 of the CAISO Tariff, Testimony by Alaywan, Z.; Docket No. ER99-3301-000, 1999.

6. Introducing the Rational Buyer changes to the ancillary Service Auction under Amendment No. 20 of the CAISO Tariff; Testimony by Alaywan, Z.; Docket No ER99-3879-000, 1999.

7. Reliability Must Run Tariff, Docket No ER98-441, Testimony by Alaywan, Z.; ER98-1019-000 and El Segundo Power, Docket No. ER98-2550-000, 2000.

8. Instituting a New Congestion Zone (ZP26) in the California Market, Testimony by Alaywan, Z.; Docket No. ER-03-683, 2000.

9. Reliability Must Run Tariff, Testimony by Alaywan, Z.; Docket No ER98-495- 000, ER98-1614, ER98-2145; Duke Energy Moss Landing ER98-2668 and ER98-4300; ER98-2669-000 and ER98-4296-000, 2001.

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11. Instituting a Transmission Revenue Requirement for Transmission outside California, Testimony by Alaywan, Z.; Docket No. El-03-15-000, December 2004.

12. Instituting a Decremental Reference Price in CAISO Markets, Testimony by Alaywan, Z.; Docket No. ER-04-938-001, September 2004.

13. Generation Payment under CAISO Market, Attachment Outlining the proposed payments for generators under CAISO markets, Testimony by Alaywan, Z.; Docket No. ER04-938-September 16, 2004.

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16. On Behalf of SMUD, Agreements Governing the Transmission Operation and Rates, Terms and Conditions of Service over the 3,200 MW the Pacific-AC Intertie ("PACI")", Declaration submitted to FERC. Testimony by Alaywan, Z.; Docket Nos. ER07-882-000, ER07-967-000, July 30, 2007.

17. On Behalf of Western Grid Development; Western Grid Requests Commission finding that its proposed energy storage device projects are wholesale transmission facilities, as well as Commission approval of certain incentive rate treatments for the Projects under Federal Power Act (FPA). Testimony by Alaywan, Z.; Harris, P and Perez, A.; 'Docket, No EL10-19-000, 2008

18. On Behalf of Opti Solar LLC, Opti solar generation interconnection, Testimony by Alaywan, Z; Docket No. ER08-1317-000 000, October 27, 2008.

19. On Behalf of Transbay Cable, An Economic Benefit Evaluation of the TransBay Cable", comprehensive economic and reliability evaluation of the TransBay Cable, a 230 kV cable across the San Francisco Bay, Trans Bay Cable LLC, Cost of Service Rate Filing, FERC Docket No. ER10-116-000, TBC3, October 23, 2009. The project is currently on line.

20. On Behalf of Desert Southwest Power LLC, Petition for Declaratory Order Allowing Incentive Rate Treatment of Desert Southwest Power LLC", ZGlobal performed a cost benefit analysis for a planned 500 kV transmission line in Southern California, March 30, 2010.

THE STATE OF CALIFORNIA

21. On behalf of the State of California Governor's office, testified in front of a panels of FERC, CPUC, SCE, PG&E, SDGE and California Large customers that CAISO systems and Market are ready to open on 3/31/1998. Three weeks Testimony by Alaywan, Z. Certification from the panels was unanimously obtained and CAISO went into operation on 3/31/1998.

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23. State Senate Select Committee Investigations and reposts regarding California Energy Crisis –This is the first hearing held on April 18, 2001 in Sacramento, CA by the Senate Select Committee to Investigate Price Manipulation of the Wholesale Energy Market. Testimony by Alaywan, Z.

24. State Senator Dunn hearing on 1/21/03. Issues include C66 protocol discussion, the fictitious load, and the MD02 update. (Stock #1207-S; $9.16 - includes tax s/h) (2/03), How to finance these price increases. (Stock #1082-S; $5.93 –includes tax s/h) (4/01). Testimony by Alaywan, Z.

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28. In the Matter of the Application of Southern California Edison Company (U338-E) for a Certificate of Public Convenience and Necessity Concerning the Antelope-Pardee 500 kV (Segment 1) Transmission Project as Required by Decision 04-06-010", Testimony by Alaywan, Z; California PUC Application 04-12-007.

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dispute between the State of California and Powerex. The State of California Receive a settlement of 750 million.

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7. "Marginal Unit Average Costs Based Clearing Prices" Final Report, PG&E/PUC, August 1996.

8. "Data Validation of Market Based Electric Operation" FERC Technical Conference, 1997.

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34. “Scheduling Restriction of the Cities of Anaheim and Riverside” by Alaywan, Z., testimony submitted to FERC, Docket No. EL03-15-000 and EL03-20-000, April 8, 2004.]
35. “Transmission Economic Assessment Methodology (TEAM)” CAISO, June 2004.
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EXHIBIT 5

ISO 2016-2017 Transmission Planning Process

Supplemental Sensitivity Analysis: Benefits Analysis of Large Energy Storage

January 4, 2018

Contents

1. Introduction

This report summarizes the informational studies conducted by the ISO to assess the benefits large scale energy storage projects may provide to ratepayers in the ISO footprint as the state moves towards higher renewable generation levels and provides the results of the most recent sensitivity results that were conducted in 2017 as an extension of the 2016-2017 planning cycle studies.

As discussed in more detail below, the 2016-2017 Base Case assumptions generally leaned to underestimate the value the large scale storage is reasonably able to provide, leading to the additional sensitivity analysis performed in 2017.

Given the evolution of the analysis over several years, it is necessary to review the background of the past efforts, to put into context the latest results and the observations drawn from those results.

It must also be noted that the planning assumptions included in the additional sensitivity analysis were finalized in early 2017. This analysis does not reflect ongoing evolution of the CPUC's Integrated Resource Planning proceeding, or changes in planning assumptions being made through that process.

2. Background

During the 2016-2017 planning cycle, the ISO undertook further study of the benefits large scale energy storage projects may provide to ratepayers in the ISO footprint as the state moves from the 33 percent RPS to a 50 percent RPS. This analysis began in the 2015-2016 transmission planning cycle with a 40 percent RPS-based analysis that was later updated to a 50 percent RPS-based analysis.[1] The 2016-2017 study used the same methodology as the previous ones and provided a further update using the latest assumptions and load forecasts, and assessed the benefits in reduction of renewable generation curtailment, CO2 emission and production cost as well as the financial costs to achieve the benefits. The ISO also expanded the study scope to consider potential locational benefits.

The study and results were documented in Section 6.5 of the 2016-2017 Transmission Plan.

The study was provided on an information-only basis and the results are dependent on the assumptions made in the study. The methodology, assumptions, and results of the study are set out in this section.

Initial Base Case in 2016-2017 Analysis

The 2016-2017 special study was conducted based on the 50 percent RPS "in-state portfolio with full capacity deliverability" portfolio the CPUC provided for the ISO 2016-2017 50 percent RPS special studies. The 50 percent RPS Base Case was developed based on the Default Scenario of the CPUC 2016

[1] See http://www.caiso.com/Documents/Board-Approved2015-2016TransmissionPlan.pdf and http://www.caiso.com/Documents/BulkEnergyStorageResource-2015-2016SpecialStudyUpdatedfrom40to50Percent.pdf

LTPP/TPP Assumptions and Scenarios.[2] The assumptions have some major changes compared to that of the last 50 percent RPS based bulk energy storage study in the 2015-2016 transmission planning cycle. The changes are mostly in the following areas:

- The retirement of non-dispatchable generation resources;
- Dispatchability of CHP resources;
- Energy forecast and Additional Achievable Energy Efficiency (AAEE);
- Renewable energy needed to achieve the 50 percent RPS target (not curtailment included); and
- The prices for renewable curtailment.

Table 1 below has the comparison of these changes.

Table 1: Comparison of Assumptions with Major Changes

Assumption	2016-2017 TPP 50% RPS Study	2015-2016 TPP 50% RPS Study
Changes in non-dispatchable generation resources	Diablo Canyon nuclear plant (2,300 MW) is retired 2,786 MW CHP in operation	Diablo Canyon in operation 4,684 MW CHP in operation
Dispatchability of CHP resources	50% of the 2,786 MW CHP is dispatchable	All 4,684 MW CHP is non-dispatchable
California load forecast	64,009 MW 1-in-2 No AAEE non-coincident peak load 301,480 GWh energy	70,763 MW 1-in-2 No AAEE non-coincident peak load 322,218 GWh energy
California AAEE	9,418 MW non-coincident peak impact 39,779 GWh energy CEC provided hourly profiles that usually have higher values in the late afternoon and early evening	5,713 MW non-coincident peak impact 24,535 GWh energy No hourly profile, offsetting load proportionally to the hourly load values
California RPS Portfolio	36,776 MW installed capacity 110,288 GWh energy	40,986 MW installed capacity 125,307 GWh energy
Price of renewable generation curtailment	-$15/MWh for the first 200 GWh, -$25/MWh for additional 12,400 GWh and -$300/MWh thereafter	-$300/MWh for all curtailment
Hydro condition	2005 hydro generation	2005 hydro generation
ISO maximum net export capability	2,000 MW	2,000 MW

[2] See http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M162/K005/162005377.PDF

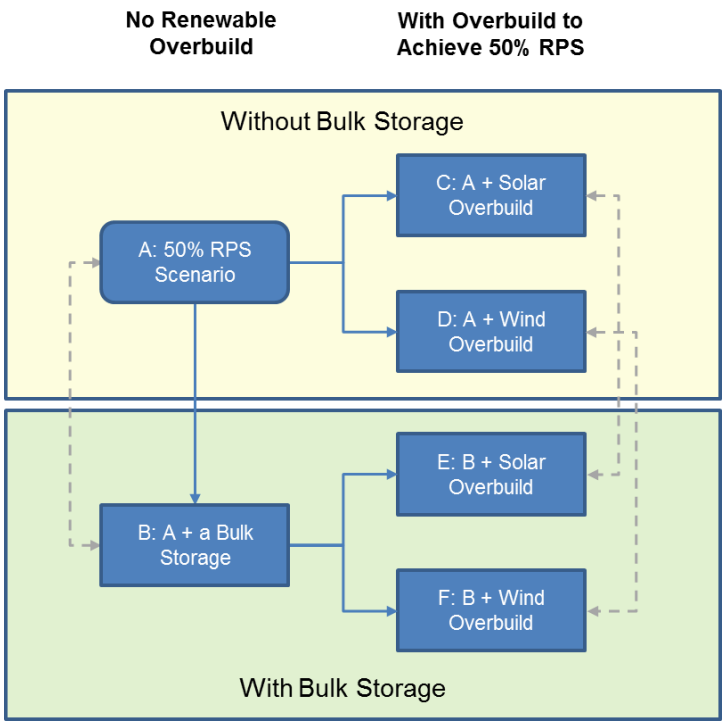
Two new bulk energy storage resources – a 500 MW and a 1400 MW resource – were added in turn to the 50 percent RPS scenario production simulation model to evaluate its contribution to reduction of renewable curtailment, CO2 emission, and production cost.

Initial Study Cases

Consistent with the studies the ISO did in the 2015-2016 transmission planning process, the study was based on production simulations – for each size of resource – of the original case and five new cases, as shown in Figure 1, as a simple comparison of two production cost simulations – with and without the bulk energy storage resource – does not determine the full benefits the resource may provide, as the presence of the storage resource may lead to different levels of success of various renewable resource mixes in achieving the 50 percent RPS target.

The five cases were all derived from the 50 percent RPS scenario Base Case, which was designated as case **A** in this study. In all cases, renewable curtailment remains unlimited. Case **B** is case **A** with the new bulk energy storage resource added. As expected, the actual renewable generation did not initially meet the state's 50 percent renewable portfolio standard (RPS) goal in the production simulations due to the amount of curtailment. In case **B** the 50 percent RPS target was still not achieved due to curtailment. In the other four cases (case **C**, **D**, **E** and **F**), additional renewable generation resources were added to the renewables portfolio of case **A** and case **B** until the actual renewable generation met the 50 percent RPS requirement despite the curtailment. The additional renewable resources are in effect the renewable overbuild needed to achieve the 50 percent RPS target and overcome the curtailment impacts on total renewable energy production.

Figure 1: Definition of Study Cases



In this study the renewable overbuilds used two alternative resources; solar and wind. Solar and wind have very different generation patterns (hourly profiles). In the 50 percent RPS scenario (case **A**), installed solar capacity was 55% of the total RPS portfolio and wind was 32%, excluding the distributed solar PV. Solar generation peaks in the midday and causes curtailment when the generation is more than the system can utilize. Solar overbuild further increased the solar dominance in the RPS portfolio and added more generation in the hours already having curtailment in case **A**. That portion of solar generation was then all curtailed. On the other hand, wind generation in California usually spreads over the whole day, with lower output in the midday than solar. Therefore, wind overbuild improved the diversification of the RPS portfolio. It has less generation to be curtailed than solar does. The needed wind overbuild was expected to be less than solar overbuild. Also the capital cost (per kW) of wind is lower than that of solar (see Table 2). As shown in Figure 1, the four cases with renewable overbuild were constructed to have either solar (case **C** and **E**) or wind (case **D** and **F**) overbuild. The purpose was to establish two bookends in term of quantity (MW) and capital cost of the overbuild. As a solution to renewable curtailment, the actual renewable overbuild should be combinations of solar and wind, as well as other types of renewable resources.

Table 2: Assumptions for Revenue Requirements and RA Revenue

Item	Generation & Transmission Costs (2016$/kW-year) [3]	NQC Peak Factor [4]	RA Revenue ($/kW-year)[5]
Large Solar In-State	242.19	47%	16.53
Large Solar Out-State	183.17	47%	16.53
Small Solar In-State	334.80	47%	16.53
Solar Thermal In-State	551.55	90%	31.66
Wind In-State	239.14	17%	5.98
Wind Out-State	223.88	45%	15.83
Pumped Storage In-State	407.91	100%	35.18

Need for additional analysis

The Base Case assumptions generally leaned to underestimate the value the pumped storage is reasonably able to provide. They provided a starting point of the studies, however, to help focus further study. As a result, the ISO committed to analyze additional sensitivity cases to assess the costs and benefits of the bulk energy storage resource in supporting integration of high penetration renewable energy in the ISO market, which is the subject of this addendum. These parameters do not affect the consideration of locational benefits of the various sites considered in the 2016-2017 Transmission Plan analysis; locational benefits did not receive further study in this sensitivity analysis.

3. Objectives of Further Study in 2017

The objective of the further study conducted in 2017 was to address the additional sensitivity analysis identified as needed in the 2016-2017 transmission planning process.

First, the Default Scenario was updated after the initial results were presented to the stakeholders in the 2016-2017 transmission planning process, changing the import from out-of-state RPS resources:

[3] See http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/LTPP/DRAFT_RESOLVE_Inputs_2016-12-21.xlsx,

https://www.wecc.biz/Reliability/2014_TEPPC_GenCapCostCalculator.xlsm and https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf

[4] See https://www.caiso.com/Documents/2012TACAreaSolar-WindFactors.xls and https://www.wecc.biz/Reliability/2024-Common-Case.zip

[5] See http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442452221

- The study assumes that 70% of out-of-state RPS generation needs to be imported into the CAISO
- The Default Scenario in 2016-2017 TPP allows the import to be exported back
- This update changes the RPS import into Category 1 and 2 RPS, which has to stay in the CAISO
- The change reduces allowed net export when there is curtailment of renewable generation in the CAISO.

Those additional sensitivity analyses focused on the following assumptions:

- Dispatchability of CHP resource (The updated Default Scenario assumed 50% of CHP resources are dispatchable – this sensitivity assumes all CHP is non-dispatchable.)
- Level of AAEE (The updated Default Scenario assumed the 2015 IEPR Mid-AAEE will be doubled in 2030 – this sensitivity assumes the 2015 IEPR Mid-AAEE forecast for 2026)
- Prices of renewable curtailment (the updated Default Scenario assumed that the first 200 GWh renewable will be curtailed at -$15/MWh, additional 12,400 GWh renewable will be curtailed at -$25/MWh, the rest at -$300/MWh. The curtailment in the Default case did not go beyond 3,000 GWh, so the -$300/MWh curtailment was never triggered.) This sensitivity assumes 4 tiers of curtailment price as noted below:

	Tier 1	**Tier 2**	**Tier 3**	**Tier 4**
Curtailment Price ($/MWh)	-15	-25	-50	-150
Max Curtailment (GWh)	200	1,300	500	All the rest

  So the effective renewable curtailment prices in this sensitivity case is lower than that in the Default Scenario.

The results of both the update to the Default Scenario and the further sensitivities are provided in this report.

4. Summary of Results

The study results from the 2016-2017 analysis and the results of the further sensitivity analysis are set out in the attachment.[6]

Based on the results of the initial study and further analysis, it can be concluded that:

[6] Also see http://www.caiso.com/Documents/Day2_ISO-Presentation_2017-2018TransmissionPlanningProcess_PreliminaryReliabilityResults.pdf

- The new pumped storage resources brought significant benefits to the system, including
  - reducing renewable curtailment and renewable overbuild needed to meet the 50% RPS target;
  - making use of the recovered renewable energy from curtailment as well as low cost out-of-state energy during hours without renewable curtailment;
  - providing lower cost energy during the net peak hours in early evening and flexibility to provide ancillary services and load-following and to help follow the load in the morning and evening ramping processes; and,
  - lowering system production cost to serve the load.
- The new pumped storage resources also took advantage of low cost out-of-state energy during hours without renewable curtailment. They also resulted in higher net import to California and slightly increased CO2 emissions[7] within California footprint.
- Pumped storage was more effective with a high solar concentration renewables portfolio than with a more diversified renewables portfolios. However a more diversified renewables portfolio has more system benefits, resulting in overall lower costs through lower curtailment, production cost and revenue requirement.
- Compared to the study with 50% RPS in 2015-2016 TPP, results of this study show significantly lower renewable curtailment, mainly due to the following assumptions:
  - Retirement of Diablo Canyon and non-dispatchable CHP resources;
  - Dispatchability of 50% of CHP resources; and
  - Lower load forecast together with higher AAEE, and the resulted lower renewable energy needed to achieve the 50% RPS target
- Because of low renewable curtailment, the effectiveness of the pumped storage resources in reducing renewable curtailment, renewable overbuild, and production costs was limited in this study.
- The net market revenue of the pumped storage resources provided only a portion of the levelized annual revenue requirements. Developing pumped storage resources would need other sources of revenue streams, which could be developed through policy decisions.

[7] The slightly increased CO2 emissions result from the assumptions regarding the GHG adder relied upon in the study and the assumption that the pumped storage would pump when low cost energy is available regardless of source. Higher GHG adders or other restrictions on these pumping opportunities would mute this impact, albeit with some corresponding impact on benefits.

- The results of the study are sensitive to the assumptions, especially the dispatchability of the CHP resources, the level and AAEE, and the prices of renewable curtailment. The conclusions about the benefits and costs of the pumped storage resources will change should the assumptions change.

- When all CHP resources are assumed to be non-dispatchable, the renewable curtailment as well as the needed renewable overbuild to meet the 50% RPS target increased significantly, as do the production costs. The pumped storage resources were able to take advantage of the higher curtailment and increased their net market revenue and benefits to the system. However, the sum of net market revenue and system benefits still fell short to meet the levelized revenue requirements of the pumped storage resources.

- With the AAEE reduced to the 2015 IEPR forecasted level (see Table 1), retail sales of electricity increases and more renewable energy is needed to meet the 50% RPS target. Then more solar is added to the RPS portfolio. As a result, more solar generation was curtailed in the simulations and more overbuild was needed. The production cost also increased because more flexible non-renewable resources were utilized to support the renewable generation. The pumped storage resources were able to take advantage of more renewable curtailment to increase their net market revenue and their contribution to the system.

- With lower renewable curtailment prices, renewable curtailment was reduced, so was the needed renewable overbuild, the system production cost, the pumped storage resources' net market revenue and their benefits to the system.

Attachment

Slide Deck – September 20, 2017 (Revised)

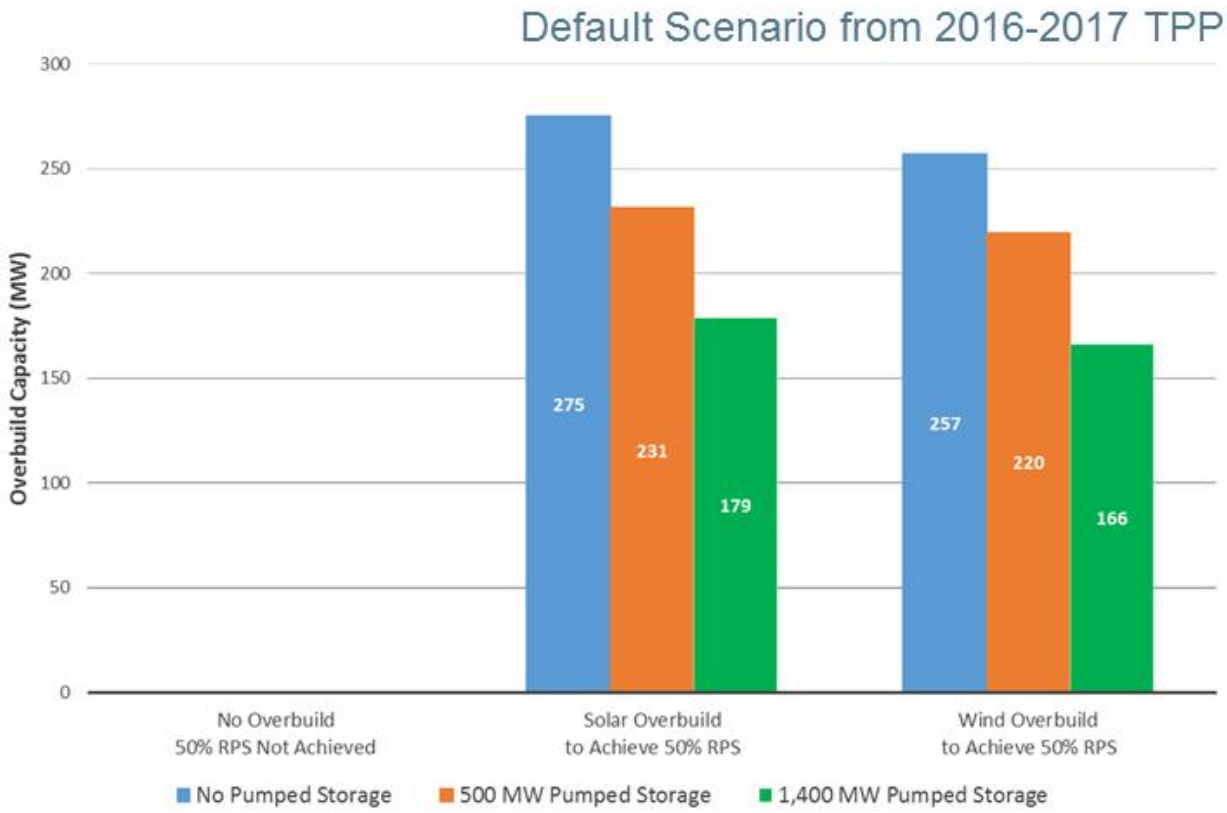
Transmission Planning Process

Stakeholder Session

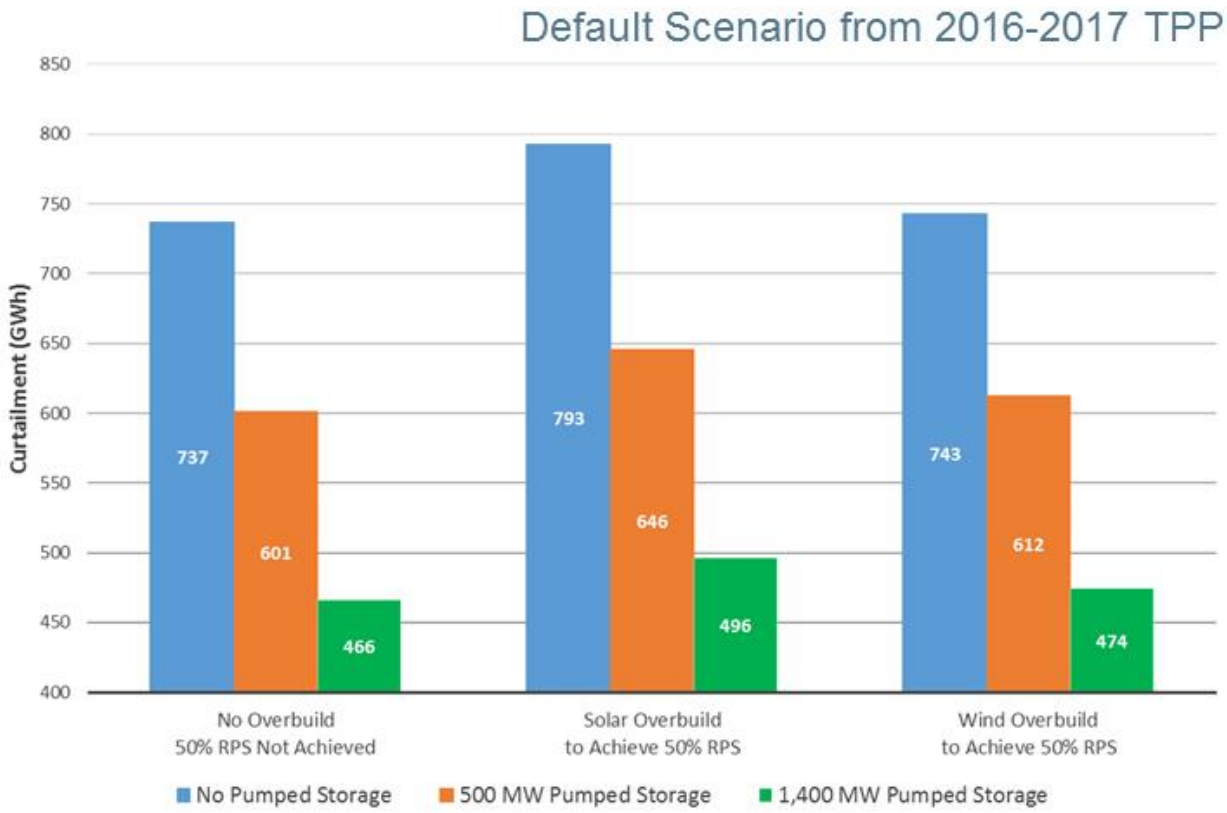
Recap of results from 2016-2017 TPP

– Default Scenario

Capacity of renewable overbuild to achieve the 50% RPS target

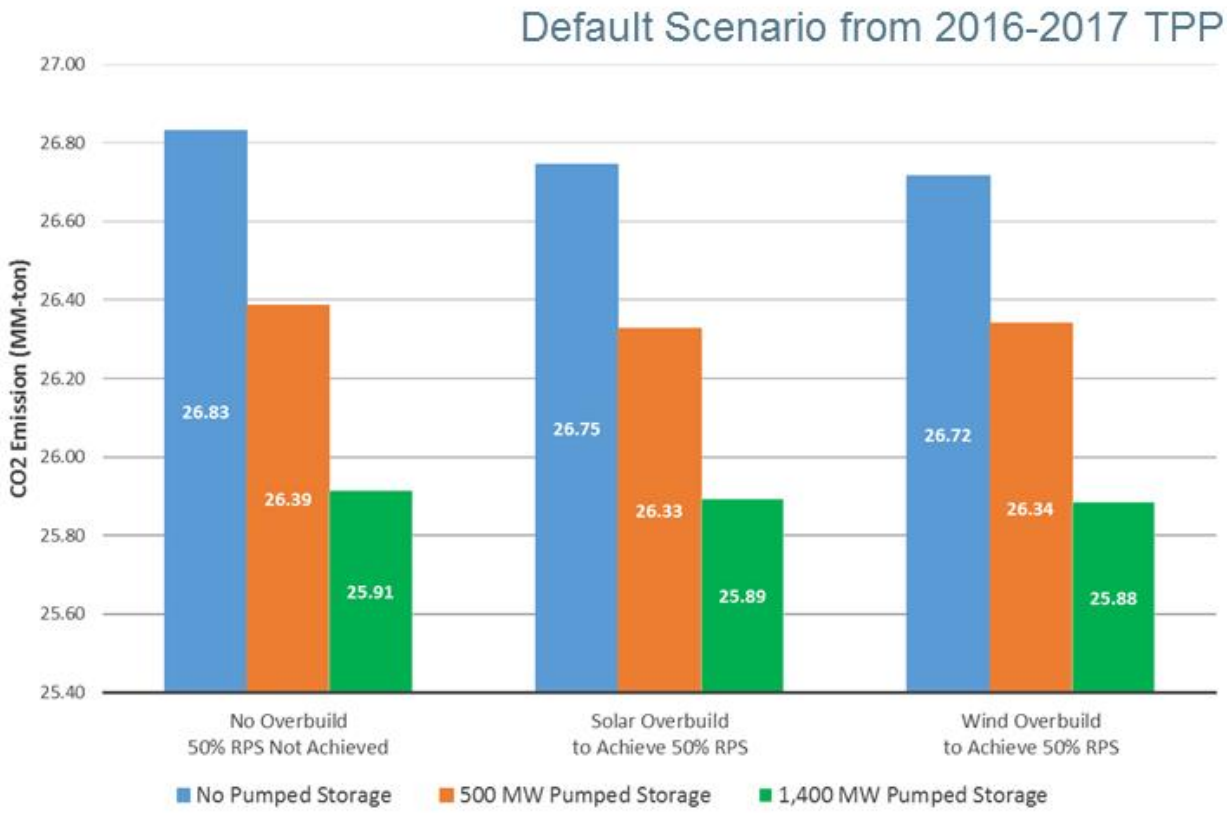


California renewable generation curtailment



Renewable curtailment price is assumed as -$15/MWh for the first 200 GWh and -$25/MWh for additional 12,400 GWh.

California CO2 emission



CA CO2 Emission includes the CO2 emission from net import