ISO 2013-2014 Transmission Planning Process Supplemental Assessment:

Harry Allen-Eldorado 500 kV Transmission Project Economic Need

Introduction

On March 20, 2014, the ISO Board of Governors approved the ISO's 2013-2014 Transmission Plan. The economic benefit analysis of the Harry Allen-Eldorado 500 kV transmission project documented in that transmission plan indicated that the line would result in net benefits for ISO ratepayers.[1] However, the ISO acknowledged that NV Energy's recent announcement of its intention to join the ISO's energy imbalance market could affect the results of that analysis and that further study was required. Further, responding to a stakeholder comment in the transmission planning process, the ISO investigated the WECC production simulation model of a transmission facility outside of the ISO footprint with the owners of that facility. This investigation led to a modeling correction of the Westwing-Mead 500 kV transmission line parameters by the owners of the transmission line. This correction was not reflected in the previous analysis. Therefore, the previous economic assessment was considered preliminary. This supplemental study evaluated the project using an updated production simulation model that included the NVE energy imbalance market modeling and the correct Westwing-Mead 500 kV transmission line parameters.

The ISO's original analysis was documented in the ISO's 2013-2014 Transmission Plan. The updated analysis in this supplemental report will be considered as a supplement to the ISO's 2013-2014 Transmission Plan. The ISO presented the results of its updated analysis to stakeholders on November 20, 2014 and provided an opportunity for stakeholder comments. A summary of stakeholder comments along with the ISO's response is provided as Attachment A. The updated analysis demonstrates that financial benefits of the Harry Allen-Eldorado 500 kV transmission project are expected to exceed its expected costs. The benefits of this project are derived both from anticipated production cost savings and through savings in capacity costs provided by increased access to out of state generation.

The proposed Harry Allen – Eldorado 500 kV line is located between NV Energy and ISO-controlled grid and would increase transfer capability between these two systems. The proposed project entails building an approximately 60 mile 500kV line between the Harry Allen substation (owned by NV Energy) and the Eldorado substation (jointly owned by Southern California Edison and other minority owners). The estimated capital cost of the line is $182 million.

[1] Chapter 5 of the 2013-1014 ISO Transmission Plan documented the results of the ISO's economic study of the proposed Harry Allen – Eldorado transmission project. Further, responding to a stakeholder comment in the transmission planning process, the ISO investigated the WECC production simulation model of a transmission facility outside of the ISO footprint with the owners of that facility. This investigation led to a correction of the Westwing-Mead 500 kV transmission line parameters by the owners of the transmission line. This correction was not reflected in the previous analysis. Therefore, the previous economic assessment was considered preliminary. This supplemental study evaluated the project using an updated production simulation model that included the NVE energy imbalance market modeling and the correct Westwing-Mead 500 kV transmission line parameters.

Technical Approach

The Harry Allen-Eldorado 500 kV transmission project economic need assessment simulates WECC system operations over an extended period in the planning horizon and identifies potential congestion in the ISO controlled grid. The study objective is to determine if this economically driven network upgrade would reduce ratepayer costs.

The study uses the unified planning assumptions and was performed after completing the reliability-driven and policy-driven transmission studies. Network upgrades identified as needed for grid reliability and renewable integration were taken as inputs and modeled in the economic planning database. In this way, the economic planning study started from a "feasible" system that meets reliability standards and policy needs. Then, the economic planning study sought to identify additional network upgrades that are cost-effective overall, and in particular, to mitigate grid congestion and increase production efficiency.

The studies used a production simulation as the primary tool to identify grid congestion and assess economic benefits created by congestion mitigation measures. The production simulation is a computationally intensive application based on security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) algorithms. The simulation is conducted for 8,760 hours for each study year, which are total number of hours in a year. The potential economic benefits are quantified as reduction of ratepayer costs based on the ISO Transmission Economic Analysis Methodology (TEAM).[2]

Different components of benefits were assessed and quantified under the economic planning study. First, production benefits were quantified by the production simulation that computes unit commitment, generator dispatch, locational marginal prices and transmission line flows over 8,760 hours in a study year. With the objective to minimize production costs, the computation balances supply and demand by dispatching economic generation while accommodating transmission constraints. The study identifies transmission congestion over the entire study period. In comparison of the "pre-project" and "post-project" study results, production benefits can be calculated from savings of production costs or ratepayer payments.

The production benefit to CAISO ratepayers includes three components: 1) decreased consumer payments; 2) increased generation revenues for generation owned by load serving entities; and 3) incrementally changed transmission congestion revenues. Such an approach is consistent with the requirements of tariff section 24.4.6.7 and TEAM principles. Production benefit is also called energy benefit. As the production simulation models both energy and reserve dispatch, we refer to the calculated benefit as a "production benefit".

Second, capacity benefits are also assessed. Capacity benefits types include system resource adequacy (RA) savings and local RA savings. The system RA benefit corresponds to a situation where a network upgrade for an importing transmission facility leads to a reduction of ISO system resource requirements, provided that out-of-state resources are less expensive to procure than in-state resources. The local capacity benefit corresponds to a situation where an upgraded transmission facility leads to a reduction of local capacity requirement in a load area.

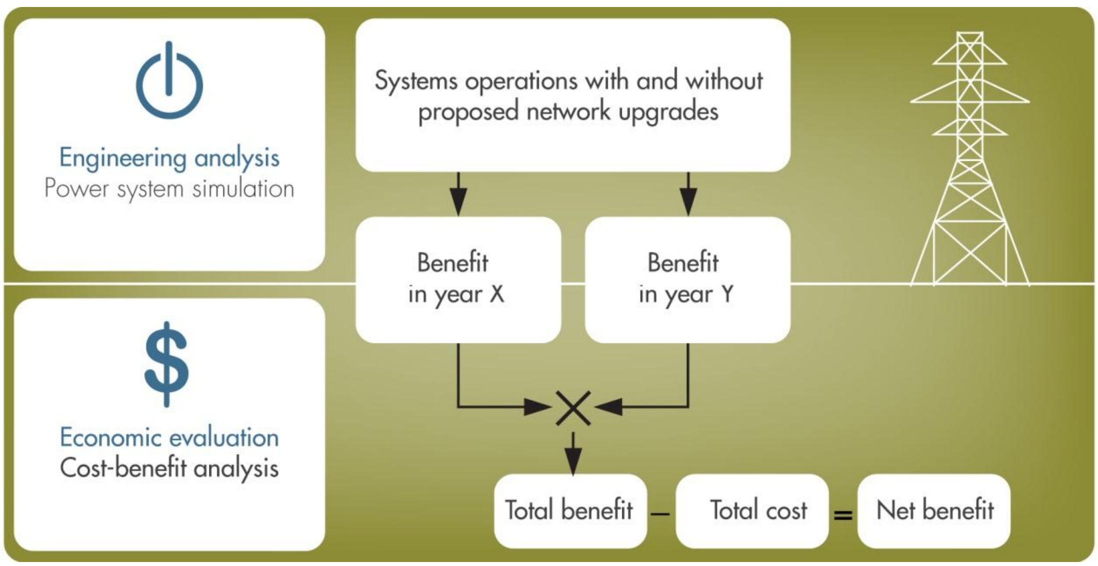
[2] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, June 2004, http://www.caiso.com/docs/2004/06/03/2004060313241622985.pdf

In addition to the production and capacity benefits, any other benefits — where applicable can also be included. However, it is not always viable to monetarily quantify other benefits – such as increase reliability benefits.

Once the total economic benefit is calculated, the benefit is weighed against the cost. To justify a proposed network upgrade, the required criterion is that the ISO ratepayer benefit needs to be greater than the cost of the network upgrade. If this criterion is met, the proposed network upgrade may be recommended for approval as an economically driven project.

The technical approach of economic planning study is depicted in Figure 1. The economic planning study starts from an engineering analysis with power system simulations (using production simulation and snapshot power flow analysis). The engineering analysis phase is the most time consuming part of the study. Based on results of the engineering analysis, the study enters the economic evaluation phase with a cost-benefit analysis.

Figure 1: Technical approach of economic planning study



Tools and Database

The ISO used the software tools listed in Table 1 for this economic planning study.

Table 1: Tools used for this economic planning study

Program name	Version	Date	Functionality
ABB GridView™	9.1	3-Oct-2014	The software program is a production simulation tool with DC power flow to simulate system operations in a continuous time period, e.g. 8,760 hours in a study year
GE PSLF™	18.0_01	24-Oct-2011	The software program is an AC power flow tool to compute line loadings and bus voltages for selected snapshots of system conditions, e.g. summer peak or spring off-peak

This study used the WECC production simulation model as a starting database. This database is often called the Transmission Expansion Planning Policy Committee (TEPPC) dataset. For this study, the ISO used the “2024 Common Case V1.0” dataset released on August 1, 2014.

Based on the TEPPC “2024 Common Case V1.0” datasets, the ISO developed the 2019 and 2024 base cases for the production simulation. In creation of the 5th year (2019) and 10th year (2024) base cases, the ISO applied numerous updates and additions to model the California power system in more detail. Those modeling updates and additions are described below.

Study Assumptions

This section summarizes major assumptions used in the economic planning study. The section also highlights the ISO enhancements and modifications to the TEPPC database.

System modeling

The ISO made several topology changes in system modeling to the TEPPC database. They are described in the following sections.

Load demand

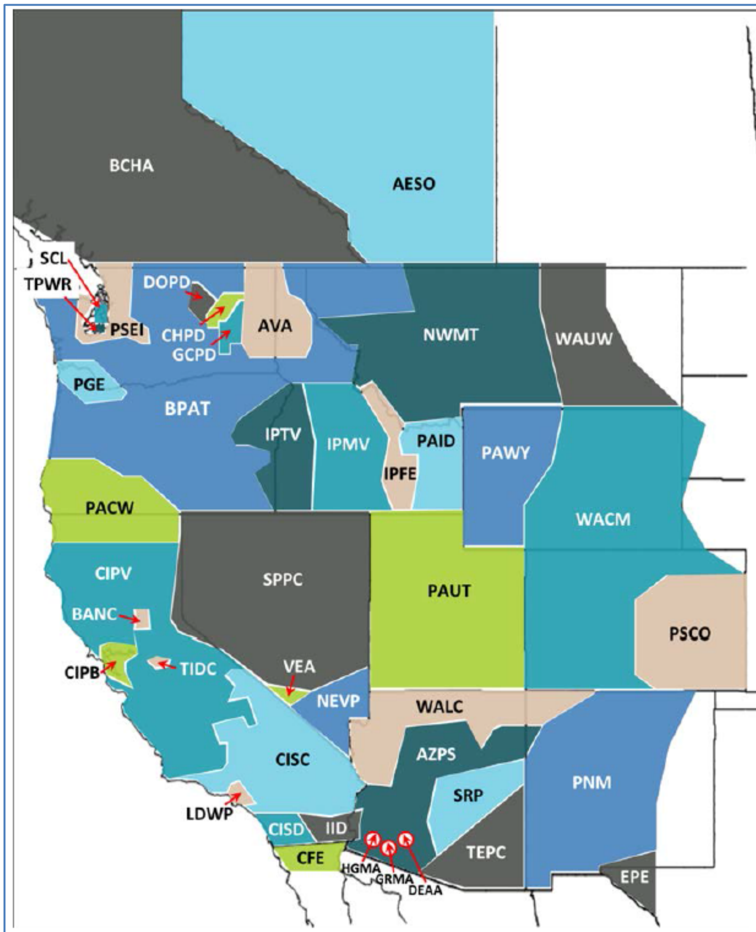
As a norm for economic planning studies, the production simulation models 1-in-2 heat wave load in the system to represent typical or average load conditions. The ISO developed base cases used load modeling data from the following sources.

- In modeling California load, the study used the CEC demand forecast. In the TEPPC database, the California load model was based on the CEC 2013 IEPR preliminary demand forecast. The ISO replaced that load model with the CEC 2013 IEPR final CEC demand forecast data published in April 2014.[3]
- In modeling load for other areas in the WECC system, the study used 2012 final forecast data from the WECC Load and Resource Subcommittee (LRS), which comes from different utilities in the WECC. In the TEPPC database, the load model was based on preliminary LRS 2012 data. The ISO replaced that load model with the latest LRS 2012 data.

Forty load areas were represented in the WECC production simulation model. Figure 2 shows the 40 WECC load areas represented in the ISO-modified database. While the load area diagram is presented below, it must be noted that this does not imply that the production simulation is conducted as a “bubble” model. Rather, the production simulation is a complete nodal model based on the full-WECC database models of all transmission lines in the system.

[3] The CEC 2013 IEPR final demand forecast is from the “CEC Mid Case and MID AAEE” available at http://www.energy.ca.gov/2013_energypolicy/documents/demand-forecast_CMF/LSE_and_Balancing_Authority_Forecasts/

Figure 2: Load areas represented in the WECC production simulation model



TEPPC Area	Area Description
AESO	Alberta Electric System Operator
AVA	Avista
AZPS	Arizona Public Service
BANC	Sacramento Municipal District
BCHA	British Columbia Hydro
BPAT	Bonneville Power Administration
CFE	Comision Federal de Electricidad
CHPD	Chelan Co PUD
CIPB	Pacific Gas & Electric Bay Area
CIPV	Pacific Gas & Electric Valley Area
CISC	Southern California Edison
CISD	San Diego Gas & Electric
DOPD	Douglas Co PUD
EPE	El Paso Electric
GCPD	Grant Co PUD
IID	Imperial Irrigation District
IPFE	Far East (Idaho Power)
IPMV	Magic Valley (Idaho Power)
IPTV	Treasure Valley (Idaho Power)
LDWP	Los Angeles Dept of Water & Power
NEVP	Nevada Power
NWMT	Northwestern Montana
PACW	PacifiCorp West
PAID	PacifiCorp East – Idaho
PAUT	PacifiCorp East – Utah
PAWY	PacifiCorp East - Wyoming
PGE	Portland Gen Electric
PNM	Public Service New Mexico
PSCO	Public Service Colorado (Xcel)
PSEI	Puget Sound Energy
SCL	Seattle City Light
SPPC	Sierra Pacific Power
SRP	Salt River Project
TEPC	Tucson Electric Power
TIDC	Turlock Irrigation District
TPWR	Tacoma Power
VEA	Valley Electric Association
WACM	Western Area Power Admin Colorado/Missouri
WALC	Western Area Power Admin Lower Colorado
WAUW	Western Area Power Admin Upper Missouri
N/A	DECA, LLC - Arlington Valley (DEAA)
N/A	Gila River Maricopa Arizona (GRMA)
N/A	Harquahala L.L.C. (HGMA)

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Each load area has an hourly load profile for the 8,760 hours in the production simulation model. Individual bus load is calculated from the area load using a load distribution pattern that was imported from a power flow base case. In the original TEPPC database only one summer load distribution pattern was modeled. The ISO enhanced the load distribution model by adding three more load distribution patterns of spring, autumn and winter. Thus, the developed ISO base cases have four load distribution patterns for different seasons.

Generation resources

The ISO replaced the TEPPC RPS modeling in California with the new 2013-2014 CPUC/CEC Commercial Interest portfolio. In addition, the study modeled two additional RPS portfolios as sensitivity cases. The modeled renewable net-short portfolios are listed in Table 2.

Table 2: Renewable net-short portfolios

Acronym	Renewable Portfolios	Study Case
CI	Commercial Interest portfolio	Base case
CS	Commercial Sensitivity portfolio	Sensitivity case
HD	High distributed generation portfolio	Sensitivity case

There are no major discrepancies between the TEPPC database and the ISO model for thermal generation. In other words, the TEPPC database has covered all the known and credible thermal resources in the planning horizon. However, the ISO replaced Once-Through Cooling (OTC) generation retirement and replacement assumptions in the TEPPC database with the latest ISO assumptions.

Transmission assumptions and modeling

The entire WECC system was represented in a nodal network in the production simulation database. Transmission limits were enforced on individual transmission lines, paths (i.e., flowgates) and nomograms.

The original TEPPC database did not enforce transmission limits for 500 kV transformers and 230 kV lines. The ISO enforced those transformer limits for this study throughout the system and enforced the 230 kV line limits in California. Such modifications were made to make sure that transmission line flows stayed within their rated limits.

Another important enhancement is the transmission contingency constraints, which the original TEPPC database did not model. In the updated database, the ISO modeled contingencies on the 500 kV and 230 kV voltage levels in the California transmission grid to make sure that in the event of losing one (and sometimes multiple) transmission facility, the remaining transmission facilities would stay within their emergency limits.

Economic planning studies start from a feasible system that meets reliability standards and policy requirements. To establish a feasible system, needed reliability-driven and policy-driven network upgrades are modeled in the base case. The ISO selected some major network upgrades and modeled them into the base case. Those selected network upgrades were usually above the 115 kV level and were deemed to have impacts on the power flows in the bulk transmission system. Network upgrades on 115 kV and lower voltage levels were assumed to be related local problems with no significant impact on the bulk transmission system.

Some of approved network upgrades were not included in the TEPPC database. The ISO rectified the database by adding those missing network upgrades. The added network upgrades are listed in Table 3 through Table 6.

Table 3: Reliability-driven network upgrades added to the database model[4]

#	Project approved or conceptual	Utility	ISO-approval	Operation year
1	Morro Bay - Mesa 230kV Line	PG&E	TP2010-2011	2017
2	Contra Costa Substation Switch Replacement	PG&E	TP2012-2013	2015
3	Kearney 230-70 kV Transformer Addition	PG&E	TP2012-2013	2015
4	Series reactor on Warnerville - Wilson 230 kV line	PG&E	TP2012-2013	2017
5	Reconductor Kearney - Herndon 230 kV line	PG&E	TP2012-2013	2017
6	Gates 500-230 kV transformer #2	PG&E	TP2012-2013	2017
7	Lockeford-Lodi Area 230 kV Development Project	PG&E	TP2012-2013	2017
8	Northern Fresno 115 kV Area Reinforcement	PG&E	TP2012-2013	2018
9	Estrella Substation Project	PG&E	TP2013-2014	2019
10	Midway-Kern PP No2 230 kV Line Project	PG&E	TP2013-2014	2019
11	Morgan Hill Reinforcement Project	PG&E	TP2013-2014	2021
12	Wheeler Ridge Junction Project	PG&E	TP2013-2014	2021
13	Gates-Gregg 230 kV Line Project	PG&E	TP2013-2014	2022

[4] The "Reliability-driven network upgrade" table lists major network upgrades of 230 kV and above. In addition, the ISO modeling additions included network upgrades of lower voltage levels. For brevity, minor and lower voltage upgrades are not listed here. For details of the listed network upgrades, please refer to relevant ISO Transmission Plan reports.

#	Project approved or conceptual	Utility	ISO-approval	Operation year
14	Barre - Ellis 230kV Reconfiguration	SCE	TP2012-2013	2013
15	Mesa Loop-in	SCE	TP2013-2014	2020
16	Victor Loop-in	SCE	TP2013-2014	2015
17	Artesian 230 kV Sub and loop-in	SDG&E	TP2013-2014	2016
18	Imperial Valley Flow Controller	SDG&E	TP2013-2014	2016
19	Bob Tap 230 kV switchyard and Bob Tap – Eldorado 230 kV line	VEA	N/A	2015

Table 4: Policy-driven network upgrades added to the database model

#	Project approved or conceptual	Utility	ISO approval	Operation year
1	IID-SCE Path 42 upgrade	SCE	TP2010-2011	2014
2	Warnerville – Belotta 230 kV line reconductoring	PG&E	TP2012-2013	2017
3	Lugo – Eldorado series capacitors and terminal equipment upgrade	SCE	TP2012-2013	2016
4	Sycamore-Penasquitos 230 kV transmission line	Undergoing solicitation process	TP2012-2013	2017
5	Lugo-Mohave series capacitor upgrade	SCE	TP2013-2014	2016

Table 5: Economically-driven network upgrades added to the database model

#	Project approved or conceptual	Utility	ISO approval	Operation year
1	Delany-Colorado River 500 kV project	SCE	TP2013-2014	2020

Table 6: GIP-related network upgrades added to the database model

#	Project approved or conceptual	Utility	Note	Operation year
1	South of Contra Costa reconductoring	PG&E	ISO LGIA	2018
2	West of Devers 230 kV series reactors (Interim facilities to be removed when West of Devers 230 kV reconductoring is complete)	SCE	ISO LGIA	2013
3	West of Devers 230 kV reconductoring	SCE	ISO LGIA	2019
4	Cool Water – Lugo 230 kV line	SCE	ISO LGIA	2019

Energy Imbalance Market (EIM) modeling

Representations for the Energy Imbalance Markets between NV Energy and the ISO and between PacifiCorp and ISO were added to the TEPPC database in the ISO study. The EIM consists of a, subhourly market covering the NV Energy, PacifiCorp West, PacifiCorp East, and ISO BAAs. EIM software automatically dispatches imbalance energy across these BAAs using a security constrained least cost dispatch algorithm. The EIM provides an interregional market for intrahour imbalance energy. To model EIM in the Gridview software reserve requirements and transmission service costs were adjusted within and between the ISO and NV Energy and PacifiCorp.

Financial Parameters Used in Cost-Benefit Analysis

A cost-benefit analysis is performed for each ISO economic planning study, in which the total costs are weighed against the total benefits of the proposed network upgrades.

For this analysis of the Harry Allen – Eldorado Project, all costs and benefits are expressed in in 2014 U.S. dollar values based on net present values discounted to 2020, which is the assumed operation year of the project.

Cost analysis

Total cost for this study refers to the net present value (in 2020, the proposed operation year) of total annual revenue requirement. The total revenue requirement includes impacts of capital cost, insurance and tax expenses, O&M expenses and other relevant costs.

In calculating the total cost of the Harry Allen – Eldorado Project, the following financial parameters were used:

- asset depreciation horizon = 50 years;
- O&M = 2 percent;
- property tax = 2 percent;
- state income tax for Nevada = 0 percent;
- inflation rate = 2 percent; and
- return on equity = Ranging from 10 percent to 11 percent;
- cost discount rate = Ranging from 7 percent (real) to 5 percent (real)

As described in this report, the ISO performed detailed financial analysis using these assumptions to convert a 2020 capital cost estimate of $182 million for the Harry Allen – Eldorado Project into annual revenue requirements over a 50 year financial lifetime, and then to calculate the present value of the annual revenue requirements stream.

Benefit analysis

Total benefit refers to the present value of the accumulated yearly benefits over the economic life of the proposed network upgrade. The yearly benefits are discounted to the present value in the proposed operation year and then the discounted yearly benefits are summed across the economic life of the project. Because of the discount, the present worth of yearly benefits diminishes very quickly in future years.[5]

In this economic planning study, engineering analysis determined the yearly benefits through production simulation and power flow analysis. Production simulation was conducted for the 5th planning year and 10th planning year. Therefore, year 2019 and 2024 benefits were calculated. For the intermediate years between 2019 and 2024 the benefits were estimated by linear interpolation.[6] For years beyond 2024 the benefits were estimated by extending the 2024 year benefit with an assumed real escalation rate of 0% per year, meaning that benefits in nominal dollars are assumed to grow at the rate of inflation.

[5] Discount of yearly benefit into the present worth is calculated by $b_i = B_i / (1 + d)^i$, where b_i and B_i are the present and future worth respectively; *d* is the discount rate; and *i* is the number of years into the future. For example, given a yearly economic benefit of $10 million, if the benefit is in the 30th year, its present worth is $1.3 million based a discount rate of 7 percent. Likewise, if the benefit is in the 40th or 50th years, its present worth is $0.7 million or $0.3 million, respectively. In essence, going into future years the yearly economic benefit worth becomes very small.

[6] The project is assumed to come online in 2020, so the benefits estimating for the year 2019 were not used directly in the total benefit calculation, but were used for calculating economic benefits of the project for the years 2020 through 2023.

The following financial parameters were used in calculating yearly benefits for use in the total benefit:

- economic life of new transmission facilities = 50 years;
- benefits escalation rate beyond year 2024 = 0 percent (real); and
- benefits discount rate = ranging from 7 percent (real) to 5 percent (real)

Cost-benefit analysis

Once the total cost and benefit are determined a cost-benefit comparison is made.

Consistent with the TEAM methodology, a social discount rate was considered in discounting the annual revenue requirements ultimately paid by customers and the economic benefits that would accrue to customers on an annual basis. A 7% (real) discount rate was applied as a very conservative base assumption for both costs and benefits. Further, for projects considered for approval, a sensitivity of 5% (real) was calculated to provide a broader perspective on the anticipated net benefits.

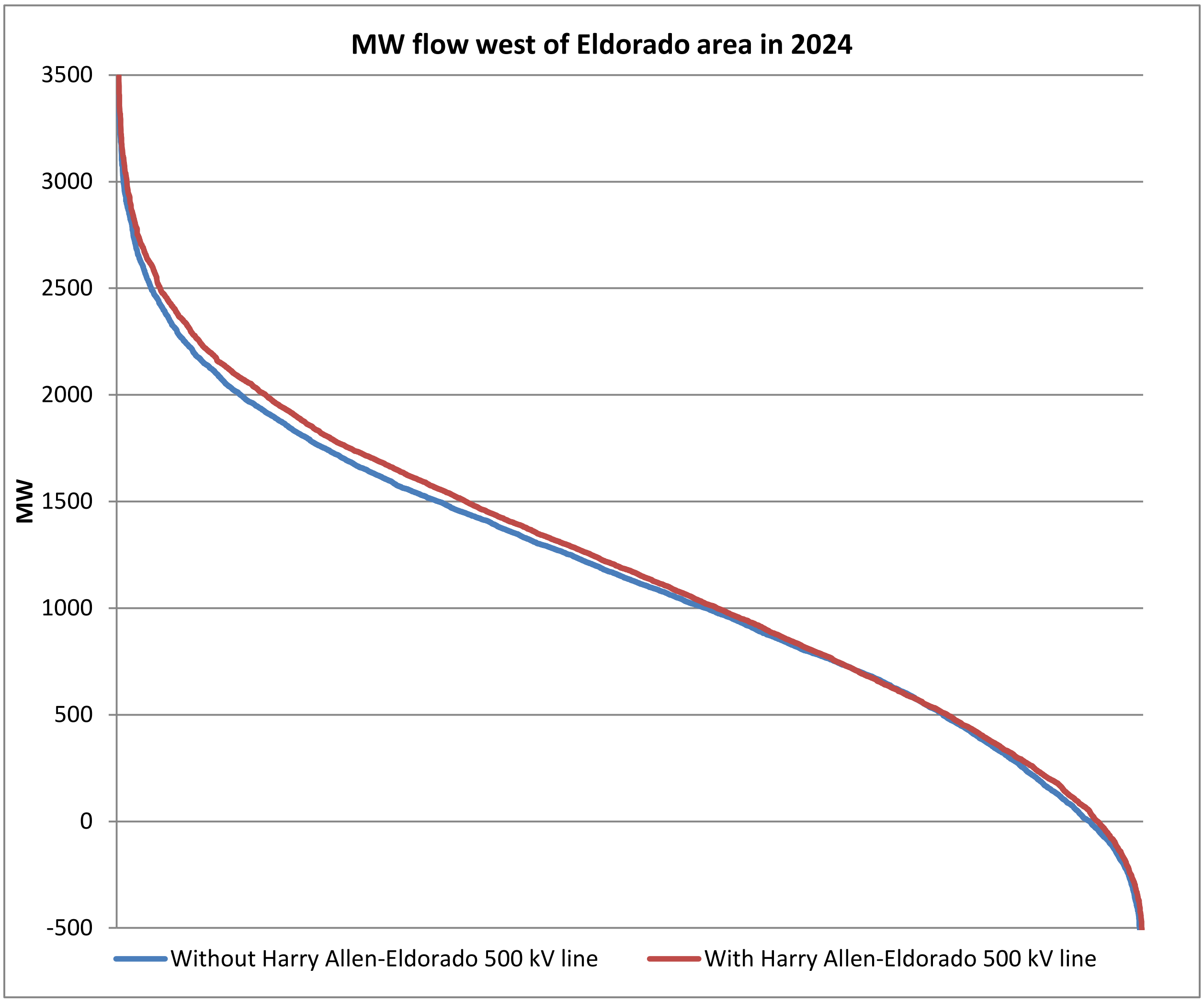
For a proposed upgrade to qualify as an economic project, the benefit has to be greater than the cost. In other words, the net benefit (calculated as cost minus gross benefit) has to be positive.

Harry Allen – Eldorado 500 kV line

Congestion analysis

Figure 3 represents simulation results showing power flows into California from Eldorado, Mohave, Marketplace, and McCullough substations (Eldorado area) before and after adding the Harry Allen-Eldorado 500 kV line project. The diagram represents flow duration curves before and after adding the project. As shown, the flow duration curve flow level increases up to 277 MW and an average of 43 MW after adding the proposed the Harry Allen – Eldorado 500 kV line.

Figure 3: West of Eldorado area Flow duration curve before and after adding the Harry Allen – Eldorado 500 kV line



Impacts to dispatch and LMP

Figure 4 shows generation dispatch changes with the addition of the Harry Allen – Eldorado 500 kV line. It can be seen that building the Harry Allen – Eldorado 500 kV line results in using more efficient generation in NV Energy area which displaces more expensive generation in southern California.

Figure 4: Generation changes with addition of the Harry Allen – Eldorado 500 kV line for Year 2024

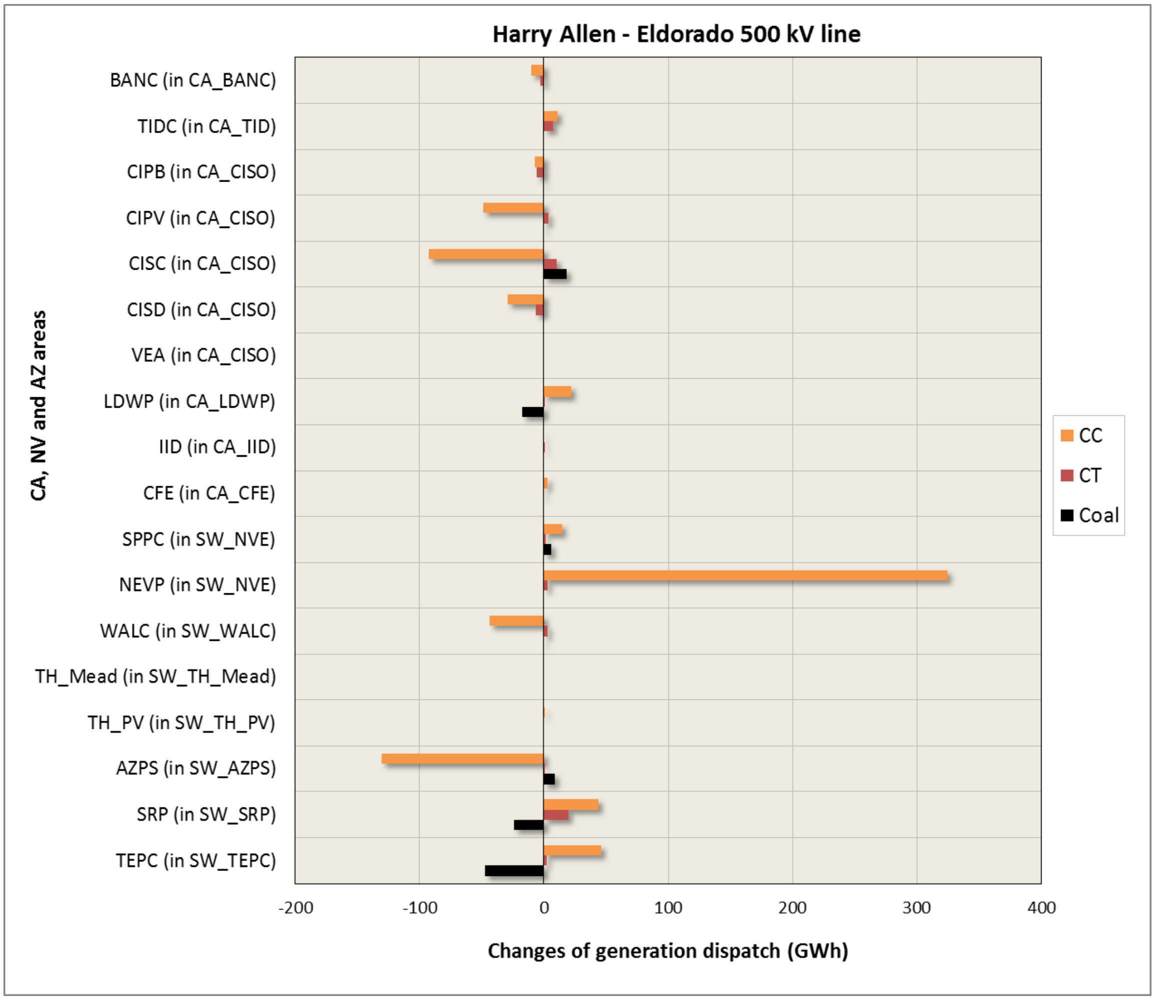
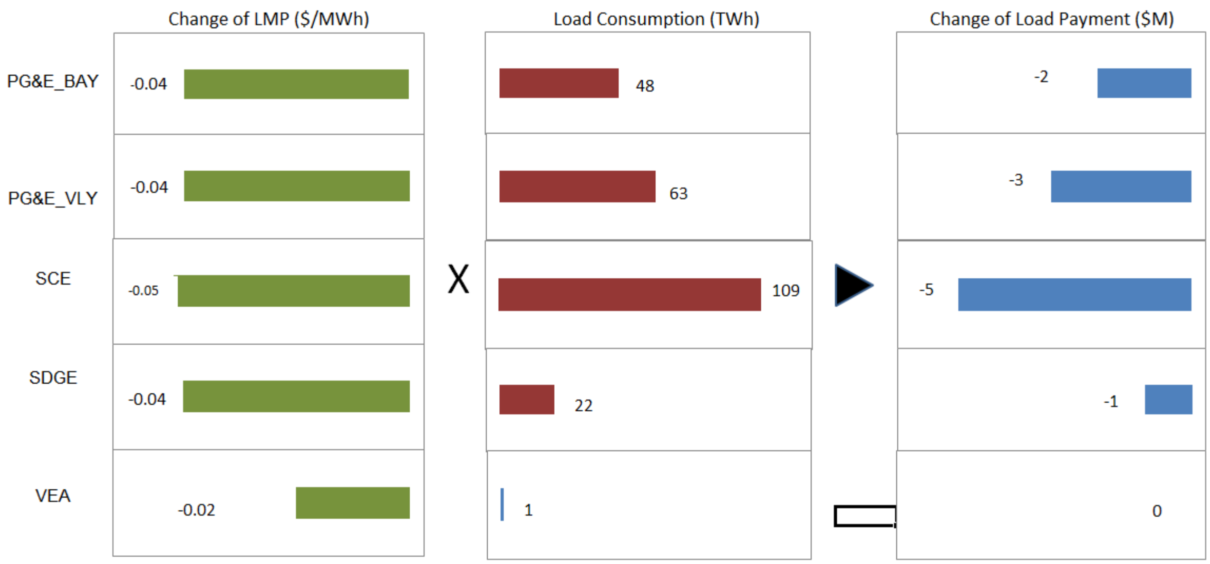


Figure 5 shows the resulting changes in load weighted LMPs and load payments. It can be seen that with the addition of the Harry Allen – Eldorado 500 kV line, the LMPs in the ISO-controlled grid decrease which reduces load payments for ISO load serving entities (PG&E, SCE, SDG&E, VEA). It can be seen from the magnitudes of LMP decreases that the beneficiaries are SCE and PG&E, followed by SDG&E. In terms of the dollar amount of load payment reduction, SCE is the biggest beneficiary.

Figure 5: LMP and load payment changes with addition of the Harry Allen – Eldorado 500 kV line



Production benefits

Based on 8,760 hourly production simulations for the two study years, benefits to ISO customers were calculated as $9.4 million in 2019 and $8.5 million in 2024, respectively. The ISO also examined, outside of the production simulation model using a traditional powerflow calculation, whether the project provided additional benefits from reducing transmission line losses. In this case, the transmission losses reduction benefit, was found to be negligible.

Table 7 provides a breakdown of yearly production benefits to ISO ratepayers computed by production simulation. The producer surplus is for load serving entity owned generation.

Table 7: Breakdown of yearly production benefits computed by production simulation

Year	Production benefit calculated by production simulation	Consumer benefit	Producer benefit	Transmission benefit
2019	$9.4M	$12.7M	($2.9M)	($0.4M)
2024	$8.5M	$10.0M	($1.8M)	$0.3M

Benefits for the years 2020 through 2023 were estimated using a linear interpolation of 2019 and 2024 year benefits. The project is assumed to come online in 2020, so the benefits estimating for the year 2019 were not used directly in the total benefit calculation, but were used for calculating economic benefits of the project for the years 2020 through 2023. For years beyond 2024 the benefits were estimated by extending the 2024 year benefit with an assumed real escalation rate of 0% per year. Table 8 lists the annual production benefits derived from the two simulation study year results.

Table 8: Yearly production benefits of building a new Harry Allen – Eldorado 500 kV line

Yearly production benefit			
Year	**Production benefit calculated by production simulation**	**Losses reduction benefit estimated outside the production simulation model**	**Final production benefit of Project**
2019	$9.4M	-	*
2020	$9.2M		$9.2M
2021	$9.0M		$9.0M
2022	$8.9M		$8.9M
2023	$8.7M		$8.7M
2024	$8.5M		$8.5M
2025	$8.5M		$8.5M
2026-2069	$8.5M		$8.5M

Production Cost Sensitivity analyses

Several sensitivity studies were performed to check the variation in economic dispatch savings under various scenarios. Production simulation models used to measure economic dispatch savings are extremely complex, so sensitivity studies are needed to estimate how the study results will change under different scenarios. For 6 percent higher load levels or 25 percent higher gas prices, the benefits increased $4.5 million to $6.5 million, and conversely for 6 percent lower load levels or 25 percent lower gas prices, the benefits decreased up to $5.5 million, as expected.

Capacity benefits

The system RA benefits are calculated as the product of:

- The incremental import capability of 200 MW to California from Nevada and the Desert Southwest
- The capacity cost differences between California and the Desert Southwest. Local Capacity Requirement (LCR) benefits are not applicable because this transmission line does affect any LCR areas.

The incremental import capacity increase is determined from the increase in West of River (WOR) transfer capability that is created by the addition of the Harry Allen – Eldorado 500 kV line project. The WECC path rating for WOR has been established as 11,200 MW under certain operating conditions. However, under summer peak operating conditions the transfer capability of this path is limited to a level that is below the WECC path rating due to contingency overload of the Mead-Marketplace 500 kV line during the common corridor contingency of the Red Bluff-Devers 500 kV lines. These overloads are primarily caused by imports from Nevada, and the Desert Southwest. Adding the Harry Allen – Eldorado 500 kV line to the system relieves this overload and creates approximately 200 MW of incremental import capability.

The Harry Allen – Eldorado system capacity benefits calculation is based on the following primary assumptions, which are further explained below:

1. California will be resource deficit by 2020;
2. The Desert Southwest will resource deficit by 2025;
3. Peaking units in the Desert Southwest can be built and operated at a lower cost than California peaking units; and
4. The addition of the Harry Allen – Eldorado line can provide incremental capacity available to California from Nevada and the Desert Southwest of approximately 200 MW starting in 2020.

<u>California Resource Deficiency[7]</u>

Recent ISO testimony submitted into the California Public Utilities Commission's Long-term Procurement Proceeding (CPUC LTPP R13-12-010) demonstrated significant capacity shortfalls in California in the year studied which was 2024. Extrapolating those results backwards would support the assumption in this study that capacity shortfalls are expected in California in 2020. The ISO conducted a system operational flexibility modeling study using the Standardized Planning Assumptions and Scenarios as determined in the CPUC Dec 24, 2012 decision (12-03-014). The operational flexibility study was performed using a PLEXOS production cost simulation model and was performed on four scenarios for the year 2022: 1) base scenario, 2) replicating TPP scenario, 3) high DG-DSM scenario, and 4) base scenario with SONGS. The base scenarios showed a 1,000 to 3,000 MW upward ancillary services and load-following

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shortage while the replicating TPP scenario showed a 4,000 MW to 5,000 MW shortage.[8] Adjusting these shortage amounts down by 800 MW based on the load growth from 2020 to 2022 results in a resource capacity shortage in 2020.

Direct and Indirect Benefits

Planning capacity benefits are frequently separated into two categories, which are referred to as "direct" and "indirect" benefits. Only the direct benefits are calculated in this document and are based on the assumption that California is able to buy lower cost capacity in the Nevada and Desert Southwest — either due to the Desert Southwest's capacity surplus or from a lower cost CT.

The indirect benefits result from a more competitive California marketplace. Increased competition generally causes market prices to be lower (the market prices are closer to marginal costs). In other words, increased competition reduces the opportunity for market power and impacts the entire spot capacity market. These indirect benefits can be significant, but to be conservative, were excluded from this analysis.

Desert Southwest Resource Deficiency

The WECC Desert Southwest sub-region is forecast to be resource surplus until 2025.[9] The NERC "2012 Long-Term Reliability Assessment" projected an anticipated planning reserve margin of 29.1 percent in 2022.[10] The most recent NERC LTRA moved Nevada out of the Desert Southwest and into the Northwest. However the Desert Southwest and Northwest are projected to have sufficient planning reserve margin in the 2024/2025 time frame in the most recent NERC LTRA as well. If the net summer system load continued to grow at annual average 1.53 percent, and if there were no significant generation retirements, the projected planning reserve margin in 2025 would be 23.3 percent as summarized in Table 9 below:[11] If 2,760 MW were retired without any significant resource additions (supply- or demand-side), the Desert Southwest would be in resource balance in 2025 from a planning reserve margin perspective.

[8] The ISO updated DR assumptions in the model after the August 26, 2013 workshop and shared the new results with an industry advisory team. The new results show a 2709 MW and 5378 MW shortage for the base scenario and replicating TPP scenario respectively.

[9] Since WECC does not prepare a summary of individual states but rather uses WECC subregions, the Desert Southwest subregion is considered to provide an accurate perspective of Arizona's resources and loads.

[10] NERC LTRA, "WECC Subregional Tables", Planning Reserve Margins WECC DSW (Desert Southwest), p. 255/355.

[11] NERC LTRA, "Demand Outlook WECC-DSW", p. 257 and 355.

Table 9: Summary of the Desert Southwest planning reserve margins

Parameter	Units	2022 (NERC Projected)	2025 (no retirements)	2025 |(2750 MW retired)
Net Total Capacity	MW	40,795	40,795	38,036
Net Internal Demand	MW	31,602	33,075	33,075
Planning Reserve Margin	Percent	29.1%	23.3%	15.0

Because the Desert Southwest is likely to have some demand- or supply-side retirements, the assumption that the Desert Southwest will not be in surplus by the year 2025 is reasonable

Relative Net Cost of CA and Desert Southwest Capacity

The cost of capacity from new peaking units in California is forecast to be $45/kw-year more than the comparable annual cost in the Desert Southwest in 2014 dollars.[12] The cost of capacity is defined as the CT annual net fixed costs (capital levelized revenue requirement, plus fixed O&M, minus the net energy and ancillary service value in the marketplace).

For purposes of this analysis, the simplifying assumption is made that the costs (CT capital and fixed O&M), as well as the market prices escalate at inflation (a real escalation rate of 0 percent). This assumption applies to costs and prices in both California and Arizona. CT costs could escalate at a rate higher than inflation, but so could market prices and thus largely offsetting each other in terms of the benefit-cost-ratio.[13]

It is also assumed that by the year 2020, the future peaking plants in California and Arizona will be flexible aero-derivative units instead of large industrial frame units.[14] These flexible units will be needed as more intermittent renewable generation is added to the system. For this analysis, the cost for an aero-derivative CT is derived from the 2014 Capital Cost Review of Power Generation Technologies prepared for WECC.[15] The resulting value is $212/kw-yr in annual capital cost revenue plus $19/kw-yr in property tax and insurance. This is based on a generic total capital cost of $1200/kw for an aero-derivative CT, multiplied by a 1.186 regional capital cost multiplier for California. Levelized fixed O&M costs for an aero-derivative CT in California

[12] The Harry Allen – Eldorado line provides import capability to Nevada and the Desert Southwest region. This analysis used Peaking capacity from Arizona, which is the lowest-cost area within the Desert Southwest region.

[13] The CT costs and the market prices are correlated. If the CT or CC costs increase at a rate greater than inflation, the market will reflect these price increases in the energy and AS prices. This is not a perfect correlation, but they are expected to be tightly linked.

[14] CEC "Status of all Projects", www.energy.ca.gov/sitingcases/all-projects.html.

[15] "Capital Cost Review of Power Generation Technologies," prepared for WECC by E3, March 2014, https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf ((technology-specific multipliers apply to capital costs; fixed O&M multiplier applies to fixed O&M for all technologies,)

were estimated as $19/kw-yr based on the same report. This resulting annual capital cost and fixed O&M is then reduced for energy and ancillary services (AS) net revenue (from the ISO Annual Report on Market Issues and Performance)[16] and adjusted for summer peak derate of the CT capacity. The resulting net cost of California capacity when resource deficit is $208/kw-year in 2014 dollars. This information is summarized in Table 10.

Table 10: Derivation of CA net capacity costs in 2014 $

Parameter	**Value**	**Units**	**Source / Notes**
CA resource deficit year	2020	Year	2012 NERC LTRA
CA aero CT annual capital cost	$231	$/kw-yr	WECC Generation Cost Report, including property tax & insurance
CA aero CT fixed O&M	$19	$/kw-yr	WECC Generation Cost Report
CA SP15 energy/AS net rev.	$52	$/kw-yr	2013 ISO Annual Report on Market Issues and Performance (3 year average for 2011-2013)
CA aero CT annual net costs	$198	$/kw-yr	Capital plus FOM minus net energy & AS revenue
Summer peak-hour derate	5%	Percent	Assumption
CA aero CT net annual fixed cost	$208	$/kw-yr	Aero annual cost divided by 95% (to adjust for summer peak derate)

The Desert Southwest's capacity cost (when resource deficit in 2025 and later) is based on the same approach as California. A summary of this calculation is contained in Table 11 below:

[16] ISO "2013 Annual Report on Market Issues and Performance", Department of Market Monitoring, (http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf), Table 1.10. Used 3 year average of Energy Revenue, plus A/S Revenue, less variable Operating Cost for 2011-2013 or SP-15 CT.

Table 11: Derivation of Desert Southwest (AZ) net capacity costs in 2014 $

Parameter	**Value**	**Units**	**Source / Notes**
AZ resource deficit year	2025	Year	2012 NERC LTRA
AZ aero CT total fixed costs	$185	$/kw-yr	WECC Generation Cost Report
AZ aero CT fixed O&M	$16	$/kw-yr	WECC Generation Cost Report
AZ energy / AS net rev.	$47	$/kw-yr	Assumption (90% of SP15)
AZ net aero fixed costs	$155	$/kw-yr	Capital plus FOM minus net energy & AS revenue
Summer peak-hour derate	5%	Percent	Assumption
AZ aero net annual fixed cost	$163	$/kw-yr	Aero annual cost divided by 95% (to adjust for summer peak derate)

The Generation Cost study for WECC provides separate capital and fixed O&M costs by state and province. The report states that the Arizona CT capital and fixed O&M costs are estimated to be 81 percent and 86 percent of the California costs, respectively.[17]

The sum of the Arizona capital and fixed O&M costs are derived by applying these percentages to the California costs to ensure a consistent basis for cost comparisons. The total CT capital and fixed O&M costs are calculated to be $201/kw-year. This cost is decreased by the assumed Arizona energy/AS revenue[18] and increased due to the summer peak derate of 5 percent. The resulting net cost of Arizona new resource capacity is $163/kw-yr in 2012 $, or $45/kw-year less than California capacity.

The Desert Southwest is not projected to become resource deficient until 2025. Prior to that time the capacity market prices there would prevail for the incremental capacity purchases over the Harry Allen – Eldorado line. There is a lack of public information on the current Arizona spot capacity price. It is assumed that $5/kw-month for the four summer months (June – September) or $21/kw-year in 2012 (2014 dollars) is a reasonable current market price estimate. The assumed market price for 2012 is then interpolated each year up to the net cost of an Arizona aero CT in 2025 based on the rate at which loads in the Desert Southwest are expected to approach 2025 levels. These annual estimates are summarized in Table 12 as well as the computed annual benefit.

[17] See Table 35 of WECC Generation Cost report.
[18] A comparison of Palo Verde to Inland hourly energy prices for the period of July 5-31, 2013 resulted in a 9.3 percent reduction in energy prices in Arizona. This figure was rounded to 10 percent and used as the energy / AS differential between California and Arizona.

Table 12: Annual capacity benefit (2014 dollars) based on 200 MW Increase in Import Capability to CAISO from Nevada and the Desert Southwest

Year[19]	**AZ Market Price ($/kw-yr)**	**AZ CT Cost ($/kw-yr)**	**SP15 CT Cost ($/kw-yr)**	**CAISO Capacity Benefit ($/kw-yr)**	**CAISO Capacity Benefit (mil. $)**
2012	$19				
2013	$29				
2014	$40				
2015	$51				
2016	$62				
2017	$73				
2018	$84				
2019	$95				
2020	$107		$200	$101	$19.7
2021	$119		$208	$89	$17.4
2022	$130		$208	$77	$15.1
2023	$143		$208	$45	$12.7
2024	$155		$208	$45	$10.3
2025	$163	$163	$208	$45	$8.8
2026-2069		$163	$208	$45	$8.8

The Harry Allen - Eldorado transmission upgrade is assumed to have a 50-year economic life, the first eight years of capacity benefits are shown in the table below. The annual capacity value is $8.8 million per year in 2014 dollars from 2025 through 2069, assuming that the CT costs and market prices have a zero real escalation rate. The levelized ISO capacity benefit is $10.8 million per year in 2014 dollars. The calculation of the Harry Allen – Eldorado planning capacity benefits is estimated below.

[19] This economic study originated in 2012. Hence, the first year for projected market prices is 2012 and not a later year.

Other Benefits

In addition to economic benefits, the Harry Allen-Eldorado 500 kV line project would provide both reliability benefits and renewable integration benefits. In terms of specific reliability benefits, the project would mitigate contingency overloads on the Mead Substation-Bob Substation 230 kV line in VEA caused by five different Category C overlapping contingencies identified in a reliability assessment model representing summer peak conditions in 2024. Those five contingencies are listed below. In terms of specific renewable integration benefits, the 200 MW of increased import capacity would provide access to flexible generation capacity needed for renewable integration.

Bob – Mead 230kV Line Overload

For the 2024 peak load scenario studied in the 2014-2015 Transmission Planning Process, Bob – Mead 230kV line is overloaded for the following N-1-1 outage combinations –

- Mead – Marketplace 500kV line outage followed by Crystal – McCullough 500kV line outage
- Mead – Marketplace 500kV line outage followed by Moenkopi - Eldorado 500kV line outage
- Mead – Marketplace 500kV line outage followed by Eldorado 500/230 kV AA bank outage
- Lugo - Victorville 500kV line outage followed by Eldorado - McCullough 500kV line outage
- Moenkopi – Eldorado 500kV line outage followed by Eldorado - McCullough 500kV line outage

The proposed Harry Allen-Eldorado 500 kV line project would mitigate these contingency overloads.

Cost Estimates

For the proposed Harry Allen – Eldorado 500 kV line, the capital cost is estimated as $182 million while the total cost (revenue requirement) is estimated at $240 million using financial calculations based on assumptions described earlier in this report, including a 0% state income tax for Nevada. A range of revenue requirements were estimated assuming a 10% to 11% return on equity and 5% to 7% discount rate. The cost estimates are listed in the tables below.

Table 13: Cost estimates for the proposed Harry Allen – Eldorado 500 kV line

NPV of annualized revenue requirement, 2014 dollars		
	5% Real Discount Rate	**7% Real Discount Rate**
10% ROE	$288M	$240M
11% ROE	$301M	$252M

Cost-benefit analysis

Based on yearly benefits described above, the total benefit is calculated in the present value based on the assumed operation year. A cost-benefit analysis is provided in the table below resulting in a benefit cost ratio of 1.06 to 1.20 for the project.

Table 14: Cost-benefit analysis of the proposed Harry Allen – Eldorado 500 kV line

NPV of annualized revenue requirement, 2014 dollars				
	5% Real Discount Rate, 10% ROE	**5% Real Discount Rate, 11% ROE**	**7% Real Discount Rate, 10% ROE**	**7% Real Discount Rate, 11% ROE**
Total Benefit	$346M	$346M	$267M	$267M
Total Cost	$288M	$301M	$240M	$252M
Benefit-cost ratio	1.20	1.15	1.11	1.06

Recommendation

The updated economic analysis shown in Table 14 demonstrates that financial benefits of the Harry Allen-Eldorado 500 kV transmission project are expected to exceed its expected costs.

In addition to these economic benefits, the Harry Allen-Eldorado 500 kV project would also provide both reliability benefits and renewable integration benefits.

Based on this analysis, Management recommends proceeding with the Harry Allen 500 kV transmission project. However, the economic justification for the project is heavily dependent on its estimated cost and, as a result, Management will plan to carefully scrutinize and assess the cost containment capabilities and commitments provided by project sponsors with respect to the estimated cost assumed in the ISO's economic analysis.

Attachment A

The ISO received comments on the CAISO Harry Allen-Eldorado 500 kV line project economic analysis results stakeholder meeting discussion held on November 20, 2014[1] from the following:

1. Bay Area Municipal Transmission group (BAMx)
2. California Public Utilities Commissions (CPUC)
3. LS Power Development (LS Power)
4. Pacific Gas & Electric (PG&E)
5. Southern California Edison (SCE)

Copies of the comments submitted are located on the *2014-2015 Transmission planning process* page at http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=DC8C3E59-F7E6-41E5-BDFB-A0CB43BB4EB2.

The following are the ISO's responses to the comments.

[1] For stakeholder convenience the Harry Allen-Eldorado 500 kV line project economic analysis was presented during the regularly scheduled meeting for the 2014-2015 Transmission Planning process held on November 19 and 20th, 2014.

No	Comment Submitted	ISO response
1	**Bay Area Municipal Transmission group (BAMx)** **Submitted by: Robert Jenkins, Barry Flynn and Pushkar Wagle**	
1a	***CAISO Needs to Perform Sensitivity Analysis for Capacity Benefits*** The CAISO's preliminary findings indicate substantial capacity benefits associated with the Harry Allen-Eldorado 500 kV line project (HAE). The CAISO's most recent capacity benefits calculations as presented during the November 19-20, 2014 stakeholder meetings are projected to be around **$10.2M** per year or **$141M** ($171M) over fifty years using a 7% (5%) discount factor. We understand the CAISO has derived capacity benefits based on the assumptions that California will continue to have a resource adequacy requirement and that Nevada can be the source of contracted capacity to serve California load. Additionally, a key assumption for these savings is that the future cost of capacity in Nevada will be significantly less than the cost in California. For these assumptions to hold true in the long run, the following conditions need to persist: *A need in California for system capacity above current in-state capacity plus expected future capacity needed for local and flexibility requirements. *The capital and fixed operating costs for a peaking unit must remain less in Nevada as compared with a California peaking unit or preferred resource, and translate into a system capacity price difference that will be passed on to the buyers. *There will be a greater resource surplus in Nevada than in California during the early years of the project resulting in a lower demand for capacity in Nevada as compared to California. BAMx considers such a set of conditions to be unlikely. Alternative scenarios are much more likely, given that California has a surplus of system resource adequacy (RA) capacity with projected planning reserve margins of **118%** in **2030** and **115%** in **2034** as modeled in the CPUC's latest RPS Calculator (Version 6.0, "System_Capacity" tab 9). The CAISO analysis assumes California will be resource deficient by 2020-22. In the past, CAISO included a source to indicate the California resource deficiency in 2022, but in this case CAISO identified only flexibility deficiencies, rather than system resource deficiencies. So far, the CAISO has not provided any justification why new	The ISO's system capacity need studies referenced in the 2013-2014 Transmission Plan and in the Supplemental Assessment of the Harry Allen-Eldorado 500 kV Transmission Line Project Economic Need (Supplemental Assessment) have consistently demonstrated a resource capacity need in the 2020 time frame. Those studies assumed the CPUC-authorized local procurement, including flexible conventional resources, were in-service. Given that NV Energy has agreed to participate in the ISO's energy imbalance market (EIM), flexible capacity in Nevada can satisfy the flexible resource capacity and traditional resource capacity needs of the CAISO. Please see response above regarding NV Energy's participation in EIM. The ISO is not aware that the TEAM methodology specifically prescribes an arbitrary splitting of benefits**.** The ISO has relied on past industry experience to base the assumption that the capacity market is sufficiently competitive such that the reductions in costs are reasonably expected to reach the purchaser. Further, we see this as an evolution of the TEAM methodology that will need to be clarified at some point. The Harry Allen-Eldorado project involves extending the ISO grid further to the east, enabling new resources to connect directly to the ISO-controlled grid, which further reduces expectations that new resources in Nevada and the Desert Southwest would retain an above-market premium.

No	Comment Submitted	ISO response
	resources should be assumed to be built in Nevada instead of within California to satisfy the flexible upward ancillary services and load following need. We understand that the need for flexible resources is determined by the CPUC and our expectation is that the CPUC would authorize the jurisdictional utilities to procure the needed capacity. The CAISO needs to explain why it is reasonable to assume that the Load Serving Entities (LSE) will procure this capacity from Nevada rather than resources which also have local capacity attributes. Most importantly, to the extent the out-of-state resources studied in the case of *HAE* evaluation are not within the CAISO Balancing Authority Area (BAA), unless they are Pseudo-Tie or Dynamic Scheduled resources, under current flexible resource adequacy rules, they would not be eligible to provide flexible RA capacity. While the CAISO is investigating the potential for creating mechanisms for allowing intertie resources to address the CAISO's 15-minute flexible resource needs, these mechanisms are not yet in place. Even if such mechanisms are developed in the future, unless the intertie resources can be dispatched on a 5-minute basis, their flexibility value will be lower than for resources within the CAISO BAA that are dispatchable on a 5-minute basis. The CAISO should explore alternative scenarios and evaluate their impact on the capacity benefit associated with the candidate transmission projects. Furthermore, the CAISO's capacity benefits calculations assume that the entire capacity benefit would be conferred on California consumers. The CAISO-developed Transmission Economic Assessment Methodology (TEAM), in contrast, assumes that the capacity benefit is split equally between the buyers and sellers of capacity.	
1b	***Changes in Incremental Increase in Path 46 Transfer Capability Need to be Adequately Explained*** CAISO's Final 2013-14 Transmission Plan assumed that adding the Harry Allen – Eldorado 500 kV line to the system created only **150MW** of incremental import capability. However, the analysis presented in the CAISO Stakeholder meeting on November 19-20, 2014 assumed that *HAE* increases the same import capability by **200MW**. BAMx would like to see an explanation for how the incremental capacity is calculated and why the CAISO has assumed a higher increase in transfer capability. All energy imports plus the ancillary services provided by out-of-state resources are subject to the California import limits. For instance, the CAISO's flexibility studies assume CAISO import limit of	As stated in the 2013-14 Transmission Plan, the binding constraints identified on Path 46 during summer peak conditions was the Sycamore-Suncrest 230 kV and the Imperial Valley – ECO-Miguel 500 kV lines. As explained to stakeholders in the November 19 and 20, 2014 stakeholder meeting, the ISO is now planning to bypass the series capacitors on the Sunrise and SWPL lines which will alleviate those constraints. In the November 20, 2014 Harry Allen-Eldorado economic assessment stakeholder presentation and in the Supplemental Assessment report, the binding constraint identified on Path 46 during summer peak conditions is the Mead-Marketplace 500

No	Comment Submitted	ISO response
	approximately 12,992 MW. Does *HAE* incrementally increase that limit by 200 MW? If not, it cannot be counted to provide flexible capacity.	kV line. The proposed project is more effective at meeting the new constraint and results in creating 200 MW of incremental transfer capability. The ISO's studies focused on the increased transfer capability from Nevada and the Desert Southwest during high internal renewable generation in the same area. This was considered to be the most likely stressed condition. Simultaneous ISO Import from the Northwest, Nevada, and the Southwest was not the focus of the study, but was also not considered to be a study concern. Simultaneous ISO import capability estimates are empirically based on historical resource availability and transmission capability. The allocation of imports across the various import paths is likely a critical factor in determining the theoretical maximum simultaneous ISO import capability. Increasing the amount of imports from Nevada and the Desert Southwest which is closer to the largest California load centers than imports from the Northwest would be, is most likely the best way to increase the simultaneous ISO import capability.
1c	***Discount Rate Used for NPV Calculations Should be Consistent with TEAM*** The benefit-cost ratio (BCR) under TEAM implemented for the Palo Verde Devers #2 500kV line (PVD2) project used a real discount rate of 7.16 percent. This figure represented a utility's weighted cost of capital (i.e. debt, preferred stock, and common equity). The CAISO's BCR calculations for *HAE* are presented under two different discount rates, i.e., 5% and 7%. BAMx would like the CAISO to provide a rationale for using these two discount rates rather than maintaining the discount rate of 7.16% that was originally used under the TEAM methodology.	The ISO utilizes a return on equity (ROE) that is based on the expected ROE that FERC would authorize for the project sponsor for this project. The discount rate is based on a societal perspective. Societal investment opportunities are generally different than utility investment opportunities. Societal investment opportunities with a 5% to 7% real rate of return are reasonable to expect over the next 50 years.
1d	***The Cost of HAE Should Not Be Borne Solely by CAISO Ratepayers*** The Harry Allen-Eldorado line's 75-mile length lies primarily, if not exclusively, within the service area of Nevada Power and connects to the CAISO system at	BAMx is correct that that the CAISO's analysis identifies benefits for CAISO ratepayers. There are identified economic, reliability and

No	Comment Submitted	ISO response
	its boundary at Eldorado. As such, the line connects the CAISO and WestConnect BAAs. While the CAISO's analysis shows potential benefits to the CAISO BAA, it also shows substantially increased power sales opportunities from Nevada Power-owned combined-cycled plants in southern Nevada. This strongly implies Nevada Power as a potential beneficiary as well. It appears that California electric customers are being asked to fund a transmission line in an external utility's footprint to overcome that utility's internal transmission constraints to facilitate greater electric sales to California without that utility sharing in the project cost. Because the proposed project is an interregional project that is outside the CAISO balancing area, BAMx requests that this project be considered as an Interregional Transmission Project under the CAISO's Board-approved compliance plan for FERC Order 1000 interregional requirements. While BAMx acknowledges that the various regions' compliance plans are still working their way through FERC approvals, the Harry Allen-Eldorado line is not reliability driven and therefore not time critical. With benefits potentially being incurred in both regions, this project is a strong candidate for cost sharing under FERC Order 1000. Therefore, this project should be considered in the Annual Interregional Coordination Meeting. Furthermore, through this interregional process the benefits and cost allocation associated with terminating the line at Harry Allen rather than the much closer Mead Substation can also be addressed.	renewable integration benefits identified for ISO ratepayers as described in the Supplemental Assessment. Although the line would provide additional opportunities for resource development in Nevada, it is not clear who would ultimately realize those benefits. It could be either merchant generation developers or utility owned generation. In addition, the current uncertainty over FERC Order 1000 would further exacerbate any effort to determine a cost sharing arrangement. Waiting for FERC Order 1000 inter-regional coordination issues to be resolved could take years and would forego the identified benefits for California ratepayers, unnecessarily.
1e	***Need to Seek Further Stakeholder Input Prior to Board Recommendation*** This proposed project has not been sufficiently analyzed and reviewed with stakeholders. At the one stakeholder meeting on November 20th that contained a review of this project, some stakeholders were referred to analysis performed on another line to obtain data assumptions made about this project. Also at the meeting, the CAISO indicated that the analysis shared was preliminary and subject to change. Stakeholders were told that CAISO Management had not decided whether to recommend the project to the Board, yet indicated Staff expected to bring a recommendation to the Board at the upcoming December Board meeting. This will leave stakeholders a few days at best to review the latest analysis and decide what their response should be. This is not a normal process and does not provide adequate time for Stakeholder input.	The Harry Allen-Eldorado 500 kV transmission line project has been analyzed in the last two transmission planning cycles, with generally favorable results. The most recent updated analysis contained in the Supplemental Assessment report follows the same methodology as the recent Delaney-Colorado River 500 kV line economic analysis. Stakeholders have essentially participated in two years of study on the Harry Allen-Eldorado project which is sufficient time for providing input. Further, management provided this final round for stakeholder input prior to finalizing its recommendation.

No	Comment Submitted	ISO Response
2	**California Public Utilities Commission (CPUC)** **Submitted by: Keith White**	
2a	***3.* Capacity Benefits Accounting for Over Half of the Value Attributed to the Harry Allen-Eldorado Transmission Project Should be Calculated in a More Robust Manner Including Circumstances that May Yield Significantly Lower Benefits, also Recognizing that When Considering the Range of Energy and Capacity Benefit Uncertainties this Project May Not Be Cost- Effective, at Least if Funded Entirely by California.** Preliminary results presented for economic assessment of the Harry Allen-Eldorado (HA-E) transmission project show a benefit-cost ratio of 1.06 and 1.14 for 7% and 5% real discount rates, respectively. Energy benefits based on locational marginal prices accounted for slightly less than half of total benefits and across a range of sensitivities ranged from zero (high DG RPS portfolio) to almost 2X the benefits under base assumptions (if assuming high load growth). In contrast, only a single value was calculated for capacity benefits, based on the calculated 200 MW increase in RA import deliverability due to the HA-E project. The methodology for calculating capacity benefits was stated to be the same as the methodology used in the previous TPP cycle for calculating capacity benefits for the Delaney-Colorado River transmission project. This methodology assumes that (1) California is in capacity deficit prior to 2020, (2) the desert southwest reaches deficit in 2025, (3) from 2025 onward there is a capacity cost advantage ($41/kW-year in 2025) for new capacity obtained from the desert southwest that reflects a lower estimated levelized cost for new aeroderivative CTs ($142/kw-yr in the desert southwest vs. $182/kw-yr for California), and (4) from 2020 through 2024 the capacity cost advantage for the desert southwest is even greater (ranging from $107/kW-year to $51/kW-year) due to a capacity surplus situation in the desert southwest. An implicit assumption is that the cost advantage for sourcing capacity from the desert southwest is captured entirely by California ratepayers, and not at all by desert southwest suppliers.	See response below.

No	Comment Submitted	ISO Response
	The above assumptions give an optimistic, high-end estimate of CAISO area capacity cost savings for obtaining 200 MW of additional import RA capacity made possible by the HA-E project. The following reasonable sensitivity assumptions would lower this capacity benefit: i. Desert southwest suppliers capture a significant portion (at least 1/2, as an alternative bookend to zero) of the capacity cost advantage relative to California, ii. Existing desert southwest capacity surplus may cease to be available for export prior to 2025, especially when considering the 400 MW of such surplus already assumed (in the 2013-2014 TPP analysis) to be incrementally sold to California via the Delaney-Colorado River project. iii. The CAISO system may not need or experience full (or any) economic value for 200 MW of system RA assumed to be imported over the HA-E project, particularly not for the full assumed 2020-2069 period. This could occur either because there is not a CAISO area system capacity shortfall as early as 2020, or if there are needs for local and flexible capacity such that filling such needs would also provide "system" RA and reduce or eliminate any residual need for system RA capacity. Therefore, just as energy benefits are appropriately assessed across a range of relevant and informative sensitivities, capacity benefits for the HA-E project should also be assessed across a range of sensitivities. Such sensitivities appear to have the potential to generally yield lower, not higher, capacity benefits relative to what was presented in the November 20, 2014 meeting. Finally, we note that under FERC Order 1000 and under the CAISO and other western transmission planning regions' Order 1000 interregional filings with FERC, interregional transmission projects such as the HA-E project could be assessed for benefits accruing to multiple regions, which might share in project costs.	The following subparts correspond to the subparts in the left hand column: i. Please see response above to a similar comment from BAMx. In addition, the ISO did not consider sensitivities where generation had market power to extract profits beyond what would be obtained from a competitive market. To do so would also need to consider market power adversely impacting LMPs inside California and would tend to increase the benefits of the increased import capability provided by the Harry Allen-Eldorado 500 kV line. ii. The 200 to 300 MW of increased transfer capability identified by the ISO as attributable to the Delaney-Colorado River project was identified as being applicable to accessing additional generation in either the Desert Southwest or in Imperial County. Therefore, it is not clear how much of this increase in transfer capability will be utilized by Desert Southwest generation. iii. Please see ISO's response to similar comment from BAMx. Sensitivity studies need to be performed by the ISO for the energy benefits because most stakeholders are unable to perform those studies. However, capacity benefit economic calculations are straightforward linear calculations that are performed using a spreadsheet and can be performed by stakeholders themselves wanting to assess a broader range of impacts. However, the ISO disagrees that its capacity economic benefit assumptions are optimistic. The Harry Allen-Eldorado 500 kV line would have a capability that is much higher than 200 MW. In addition, if the Midpoint-Robinson Summit 500 kV line is built at a later date then the import capacity benefits could increase. Please see ISO's response to BAMx's comment regarding Order 1000.

No	Comment Submitted	ISO Response
3	**LS Power Development, LLC** **Submitted by: Sandeep Arora and Lawrence Willick**	
3a	**Harry Allen Eldorado Project should be recommended for CAISO Board approval:** CAISO Management should recommend the Harry Allen to Eldorado 500 kV Transmission Project ("Harry Allen-Eldorado") for approval by the Board at its December meeting. As shown by the recent CAISO studies and the economic study work done including in the 2012-2013 Transmission Plan and 2013-2014 Transmission Plan, Harry Allen-Eldorado provides economic benefits for CAISO ratepayers. At the stakeholder meeting CAISO staff mentioned that certain additional economic benefits (related to EIM) were not yet captured in the latest study runs and once quantified, will lead to an increase in total benefits. While LS Power agrees with CAISO that these additional benefits should be quantified, the benefits calculated to date are strong enough for CAISO Management to recommended Harry Allen-Eldorado for approval at the December Board meeting. Besides economic benefits, additional policy & reliability benefits also exist from this Harry Allen-Eldorado, which, although not quantified, should be factored into the decision making.	Please see the identified reliability and renewable flexibility benefits described in the Supplemental Assessment.
3b	<u>Energy & Capacity Benefits</u> As shown in CAISO studies, significant energy savings are expected by Harry Allen-Eldorado for the base case scenario and almost all sensitivity scenarios. In addition to energy benefits, significant capacity savings from Harry Allen-Eldorado exist. CAISO estimated the capacity benefits by using a methodology consistent with what was done for analyzing similar benefits from the recently approved Delany-Colorado River project. CAISO's calculation is based on system capacity shortfall projections in CAISO in future years, but only looks at the impact of the project on Path 46, while the project will provide access to additional capacity resources beyond just its impact to Path 46. LS Power supports CAISO's calculation of capacity benefits, and believes additional capacity benefits exist beyond those quantified by CAISO. CAISO recently released its Stochastic Modelling testimony for the CPUC Long Term Planning Procurement study work. This study further reinforces	Thank you for the suggestions on quantifying additional benefits which support the ISO recommendation to proceed with the project.

No	Comment Submitted	ISO Response
	CAISO's findings that there is risk of capacity shortfall in California, specifically a potential capacity shortfall of 8292 MW in 2024 to meet the 1-in-10 planning standard and avoid Stage 1 & 3 emergencies. The maximum shortfall identified in the study was 16,745 MW. The CAISO study concluded that *"The most frequent capacity shortfalls occurred in July from hours 18 to 20, after the peak load hour when solar generation production drops prior to the evening reduction in load. Traditionally planning focused only on peak load hour. With the increase in renewable generation, the traditional planning reserve margin approach focusing on peak load hour has become insufficient and outdated. The results of the CAISO's study confirm that planning to meet peak load hour requirements is not necessarily sufficient to maintain reliability."* Given this, LS Power believes that the 202 MW incremental capacity benefit is an "under-estimation", as this was calculated at the traditional peak hour, which is typically Hour 15, and only based on the impact of an increase to Path 46. If CAISO's studies are repeated for Hours 18-20, the largest hour of need, the incremental capacity benefit on Path 46 would be much greater than 202 MW, since the WOR path will not be as stressed during non-peak hours.	
3c	<u>NPV Calculation</u> LS Power believes CAISO's calculation of the net present value of the benefits of Harry Allen-Eldorado underestimates the lifetime project benefits due to the discounting of values expressed in real dollars. Slide 85 of the Day 2 presentation (Slide 10 of the Harry Allen-Eldorado analysis) identifies an annual capacity savings of $10.2 million. The next slide (Slide 86) describes the CAISO methodology of assuming constant real savings, and that the present value over 50 years of the capacity savings is $141 million (at a 7% discount rate). However, if the $10.2 million is extrapolated in constant real dollars, the net present value over 50 years should be $10.2 million x 50 = $510 million, at least at a discount rate equal to inflation. In order to perform the net present value calculation at a different discount rate, the values would first need to be escalated at inflation to year of occurrence values, then discounted back to present value at the desired discount rate. So the net present value of $10.2 million in constant real	The 7% discount rate was one end of the range of the discount rates considered from a societal perspective to reflect the time value of money in real terms. While levelizing the revenue stream provides a means to gauge the approximate value in each year in real terms, discounting using the real discount rate remains necessary to consider the present value of the revenue stream at the time the investment decision is made, consistent with the consideration of the costs.

No	Comment Submitted	ISO Response
	dollars, over 50 years, assuming 2% inflation, and a 7% discount rate would be $185 million, not $141 million, and overall the net present value of benefits calculated by CAISO should be approximately 30% higher than shown.	
3d	Incremental reliability & policy benefits of Harry Allen-Eldorado In addition to the quantified economic benefits, there are certain qualitative reliability and policy benefits of Harry Allen-Eldorado. This line helps, to a certain extent, improve the deliverability of renewables from the Imperial Valley renewable energy zone, as well as renewables in Southern Nevada. In addition the line provides improvement in reliability by reducing several post contingency line loadings as shown by studies conducted by LS Power and also documented in the 2013/14 CAISO Transmission Plan.	Please see the identified reliability and renewable flexibility benefits described in the Supplemental Assessment.
3e	EIM Benefits CAISO and NV Energy have announced the expansion of EIM markets to include NV Energy starting in 2015. Harry Allen-Eldorado will increase transmission capacity for EIM purposes and will thereby provide increased EIM benefits to CAISO and NV Energy. As CAISO stated at the November stakeholder meeting, these benefits are not yet fully quantified in the studies performed by CAISO to date and once EIM is fully modelled the economic benefits from Harry Allen-Eldorado will increase. LS Power agrees that more fully modelling EIM would help account for additional benefits that the model is currently unable to capture due to the nature of 1-hour used for the ABB Gridview study runs vs 5-min dispatch for the EIM. Further, looking at the previous EIM benefit study work done for CAISO, PacifiCorp and NV Energy by ABB and E3, new transmission capacity additions do create significant savings from dispatch efficiency improvements and reduced minimum reserve holdings, which translates to economic benefits.	The ISO agrees that further refinements to the EIM modeling is likely to reveal further benefits. However, the current modeling is comprehensive.
3f	Benefits of Earlier In Service Date Finally, LS Power would like to ensure that CAISO recognizes the many benefits of an earlier in-service date for the project. In the solicitation for the Delaney – Colorado River 500 kV transmission Line, CAISO stated there would not be any additional benefit for an in-service date for the project prior to 2020. For the Harry Allen-Eldorado 500 kV project there are many significant benefits that could be realized from an earlier in-service date:	Assuming that the project is approved, the solicitation process takes time to allow sponsors to prepare submittals and to evaluate those submittals. As a result, the successful project sponsor would not be known until close to the end of 2015, which would leave four years to permit and construct the project prior to 2020. This is a reasonably aggressive schedule, so advancing that schedule does not seem realistic.

No	Comment Submitted	ISO Response
	1. CAISO's estimated benefits of the Harry Allen-Eldorado (slide 81 of the stakeholder presentation) show higher economic dispatch savings in 2019 than 2024. Therefore an earlier in-service date would help to achieve a higher total benefits. 2. CAISO uses a relatively high discount rate, 7%, to calculate the net present value of benefits. Therefore benefits in 2019, or even an earlier year, would have a higher value to ratepayers. 3. A project with a later in-service date would have a higher cost, due to the impact of inflation and overall escalation on the project costs. At 2% per year, the impact to ratepayers of a 2020 in-service date compared to 2018 is 4%, and the impact on the overall benefit: cost ratio would also be 4%. 4. Bringing this Harry Allen-Eldorado in service sooner than 2020 is prudent as it would also help address the risk of capacity retirements due to Once Through Cooling (OTC) policy compliance. Year 2017 is a major year for OTC compliance. Over 5000 MW of existing OTC units have to either demonstrate OTC compliance by Dec 31, 2017 or else they could become inoperable starting in 2018. Bringing this new transmission line in service by June 2018 would serve as an insurance policy in case significant OTC capacity becomes unavailable in 2018. This coupled by delays in development of new resources that were authorized under the LTPP could pose significant capacity shortfalls in CAISO beginning 2018. This new project will make more out of state capacity available to CAISO thereby helping mitigate the risk of Stage 1 & 3 Emergencies. <u>Conclusion</u> LS Power encourages CAISO to seek board approval of the Harry Allen-Eldorado 500 kV Transmission Line as an economic project given the benefits demonstrated by CAISO's studies and the additional benefits identified above. In addition, LS Power encourages CAISO to recognize the benefits to ratepayers of an earlier in-service date in any solicitation conducted for the project.	However schedule could be one of the key selection factors along with cost containment. The ISO is using a real discount rate ranging from 5% to 7%.

No	Comment Submitted	ISO Response
4	**Pacific Gas & Electric** **Submitted by: Justin Bieber**	
4a	Harry Allen – Eldorado Economic Benefit Analysis PG&E shares similar concerns as other stakeholders that the assumed capacity benefit may be lower than assumed in the benefit analysis. The BCR ratio between 1.063 and 1.143 and capacity benefits that account for more than half of total gross benefits make this economic analysis very sensitive to that capacity value assumption.	Please see ISO responses to similar comments above

No	Comment Submitted	ISO Response
5	**Southern California Edison** **Submitted by: Karen Shea**	
5a	**<u>Comments Regarding the Harry Allen-El Dorado Analysis</u>** SCE is continuing to evaluate the additional information regarding the Harry Allen-El Dorado analysis that was presented at the CAISO's November 19-20 stakeholder meeting. SCE would appreciate the CAISO's response to the following: 1. Slide #10 of the Day 2 Harry Allen-Eldorado presentation says that there have been "Small updates to CT value, dollar year, etc.". SCE requests the CAISO to provide a description of those updates, particularly regarding assumptions relating to the cost of new generation capacity in California, including any differences from what was described in the 2013-14 approved transmission plan. 2. Have any changes been made to the derate assumptions that were described in the CAISO's 2013-14 approved transmission plan? If so, please describe. SCE observes this is now the second inter-regional project that will result in CAISO allocating all costs to California. We encourage the CAISO to move forward with the Order 1000 inter-regional planning process to ensure inter-regional cost allocation as soon as practical on any similar future projects.	Please see the Supplemental Assessment. The ISO has assumed that due to high ambient temperatures expected during resource shortage conditions, the combustion turbine maximum generation capability will be derated by 5%. It is assumed that the resource shortage is in California and the temperatures in California are 1 in 10 heat wave conditions. It is not assumed that Nevada and the Desert Southwest are experiencing abnormally high temperatures. The ISO is proceeding with its Order 1000 inter-regional planning process in coordination with neighboring systems as needed. In any event, inter-regional cost allocation is based on the identification of material ratepayer benefits for the areas that would also drive those areas to support a project through funding. The ISO analysis focused on California ratepayer benefits. Benefits to neighboring regions have not been quantified through the analysis or consultation to date. Moreover, waiting for FERC Order 1000 inter-regional coordination issues to be resolved could take years and would forego the identified benefits for California ratepayers, unnecessarily.