Application No.:	16-10-012
Exhibit No.:	
Witness:	Neil Millar
ALJ:	MacDonald
Commissioner:	Randolph

In the Matter of the Application of DCR TRANSMISSION, LLC for a Certificate of Public Convenience and Necessity for the Ten West Link Project	Application 16-10-012

TESTIMONY OF NEIL MILLAR
ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

December 20, 2019

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TESTIMONY OF NEIL MILLAR
ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
A.16-10-012

I. INTRODUCTION

Q1. What is your name and by whom are you employed?

A1. My name is Neil Millar. I am employed by the California Independent System Operator Corporation (CAISO), 250 Outcropping Way, Folsom, California as the Executive Director, Infrastructure Development.

Q2. Please describe your educational and professional background.

A2. I received a Bachelor of Science in Electrical Engineering degree at the University of Saskatchewan, Canada, and am a registered professional engineer in the province of Alberta.

I have been employed for over 30 years in the electricity industry, primarily with a major Canadian investor-owned utility, TransAlta Utilities, and with the Alberta Electric System Operator and its predecessor organizations. Within those organizations, I have held management and executive roles responsible for preparing, overseeing, and providing testimony for numerous transmission planning and regulatory tariff applications. I have appeared before the Alberta Energy and Utilities Board, the Alberta Utilities Commission, and the British Columbia Utilities Commission. Since November 2010, I have been employed at the CAISO, leading the Transmission Planning and Grid Asset departments.

Q3. What is the purpose of your testimony?

A3. The purpose of my testimony is twofold. First, to provide an overview of the CAISO's transmission planning process that identified the economically-driven need for the Ten West Link Project (Proposed Project), which consists of a proposed 114-mile 500 kV series-compensated transmission line extending between the Delaney Substation in Tonopah, Arizona, and the existing Colorado River Substation located west of Blythe, California. As I explain below, the CAISO approved the Proposed Project in its 2013-2014 Transmission Plan based on its economic planning studies. Second, to provide an

overview of the reasons why the Commission should find the project to be needed in this proceeding, recognizing the passage of time and other circumstances that have evolved since the project was approved in the CAISO's transmission planning process.

Q4. What are your recommendations in this proceeding?

A4. I recommend that the Commission approve the Application of DCR Transmission, LLC (DCRT) for a certificate of public convenience and necessity (CPCN) for the Proposed Project. As explained in my testimony and the supporting testimony of Mr. Yimer and Mr. Zhang, the Ten West Link Project is necessary to provide significant economic, reliability, and policy benefits to California ratepayers.

II. OVERVIEW OF THE CAISO'S TRANSMISSION PLANNING PROCESS

Q5. Please provide an overview of the CAISO's transmission planning process.

A5. The CAISO conducts an annual transmission planning process to identify and plan the development of solutions to meet the future needs of the CAISO controlled grid. This annual process culminates in the CAISO Board of Governors approving a comprehensive transmission plan. The plan identifies needed transmission solutions and authorizes their cost recovery through CAISO transmission rates, subject to regulatory approval. The CAISO develops the transmission plan in the larger context of supporting achievement of important state energy and environmental policies and facilitating the transition to a cleaner, lower emission future, while maintaining reliability through a resilient electric system.

The transmission plan identifies transmission facilities that are needed for three main purposes: reliability, public policy, and economics. In the planning process, the CAISO also considers and evaluates non-transmission alternatives, including conventional generation and preferred resources such as energy efficiency, demand response, renewable resources, and energy storage.

The annual planning process is structured in three consecutive phases with each planning cycle identified by a beginning year and a concluding year. Each annual cycle begins in January and extends into the subsequent year.

In Phase 1 of the annual transmission planning process, the CAISO establishes the assumptions and models to be used in the planning studies, develops and finalizes a study plan, and specifies the public policy mandates that CAISO planners will adopt as objectives in the current planning cycle. This phase takes roughly three months from January through March of the first year of the planning cycle. During Phase 1, the CAISO first posts a draft study plan for stakeholder review and then conducts a public stakeholder session. At the stakeholder session, the CAISO answers questions regarding the draft study plan and requests additional written comments from stakeholders. The CAISO then considers stakeholder comments in completing its final study plan.

In Phase 2, the CAISO performs studies to identify transmission needs and the necessary solutions to meet those needs, culminating in the annual comprehensive transmission plan. Phase 2 takes approximately 12 months and generally involves three additional public stakeholder sessions at which the CAISO presents preliminary and draft results for vetting with stakeholders. After each stakeholder session, the CAISO requests and considers stakeholder comments on its planning analyses. Identifying non-transmission alternatives that the CAISO can rely upon in lieu of transmission solutions also occurs during Phase 2. After this process concludes, the draft transmission plan is presented to the CAISO's Board of Governors for final review and approval. Phases 1 and 2 take a total of 15 months to complete.

During Phase 3, the CAISO solicits competitive bids for the construction and ownership of new transmission facilities identified in the approved transmission plan eligible for competition. In any given planning cycle, Phase 3 may or may not occur depending on whether the final plan includes transmission facilities that are open to competitive solicitation in accordance with criteria specified in the CAISO tariff.

Q6. Does the CAISO's annual transmission planning process assume that all transmission solutions approved in previous transmission plans will proceed?

A6. Generally, yes. Each annual study plan assumes that all transmission previously approved through earlier transmission planning processes will be developed as approved. Projects may be reviewed on a case-by-case basis if material changes in circumstance are identified by the CAISO or other stakeholders. However, these circumstances do not apply in the case of the Proposed Project, because although circumstances have evolved since the 2013-2014 Transmission Plan, the Proposed Project continues to be necessary based on the CAISO's updated economic analysis.

Q7. Please provide additional detail regarding the CAISO's process to identify economically-driven transmission solutions.

A7. As part of Phase 2 of the annual transmission planning process, the CAISO conducts high priority economic studies to determine whether economically-driven transmission solutions are necessary to reduce electric-industry related costs for CAISO ratepayers. The CAISO's economic planning studies are an integral part of the annual transmission planning process. The economic planning studies complement the reliability and policy-driven analyses documented in each annual transmission plan by exploring economically-driven transmission solutions that create opportunities to reduce ratepayer costs within the CAISO.

The CAISO conducts each year's economic studies after the completion of the reliability and policy-driven transmission studies performed as part of this transmission plan. The economic studies use production cost simulation as the primary tool to identify potential study areas, prioritize study efforts, and assess benefits. The production cost simulation identifies grid congestion and assesses economic benefits created by congestion mitigation measures. This type of economic benefit is normally categorized as an energy or production cost benefit. The production cost modeling simulation is a computationally intensive application based on the CAISO's security-constrained unit commitment

(SCUC) and security-constrained economic dispatch (SCED) algorithms. The production cost simulation is conducted for all hours for each study year.

The CAISO production cost simulation models all reliability and policy-driven transmission solutions identified in the transmission plan. This ensures that all economic planning studies are based on a transmission configuration that is consistent with the reliability and public policy results documented in the transmission plan. The CAISO then performs the economic planning studies to identify additional cost-effective transmission solutions to mitigate grid congestion and increase production efficiency within the CAISO.

Though the production cost modeling simulations focus primarily on congestion benefits, the CAISO also takes into account other economic benefits on a case-by-case basis. This augments the congestion-driven analysis and allows the CAISO to assess other economic opportunities that are not congestion-related. The CAISO can assess capacity benefits, including local capacity benefits, based on powerflow modeling. For example, the CAISO can assess whether a proposed economic transmission project reduces the need for local gas-fired generation capacity in an area by increasing transmission capacity into the area.

The CAISO preliminarily identifies preferred solutions to address reliability and policy-driven needs based on more conventional cost comparisons, *e.g.*, capital and operating costs and transmission line loss savings. During the economic study process, the CAISO expands its analysis to consider more comprehensive economic benefits that could be provided by alternative solutions. At this stage, the CAISO considers production cost and capacity benefits to determine the more efficient economic project to meet the identified needs. This can lead to replacing or upscaling a reliability or policy-driven solution with a more cost-efficient solution during the economic study process.

The CAISO quantifies potential economic benefits in terms of reductions in ratepayer costs based on the CAISO Transmission Economic Analysis Methodology (TEAM).[1] The CAISO's tariff and the related TEAM documentation set out the considerations for seeking approval of a transmission project in the CAISO transmission planning process. In determining whether additional economic transmission solutions are needed, the CAISO considers the degree to which the benefits of the transmission solutions outweigh the costs, in accordance with the procedures set forth in the Business Practice Manual and the TEAM documentation.

Q8. Please explain the interaction between the CAISO's transmission planning process and the Commission's generation and resource planning proceedings.

A8. Since the 2011-2012 planning cycle, the CAISO has relied on detailed resource planning information developed by the Commission to conduct its transmission planning analyses. Specifically, the CAISO uses Commission-developed renewable generation portfolios for information regarding the location and volume of future renewable energy development to meet the state's public policy goals. The CAISO uses these renewable generation portfolios in its reliability, public-policy, and economic transmission studies.

The CAISO's 2018-2019 transmission plan summarized the relationship between the CAISO's transmission planning process and the Commission's resource planning as follows:

> The [CAISO] formulates the public policy-related resource portfolios in collaboration with the [Commission], and with input from other state agencies including the CEC and the municipal utilities within the [CAISO] balancing authority area. The [Commission] as the agency that oversees the bulk of the supply procurement activities within the [CAISO] area, plays a primary role formulating the resource portfolios. The [CAISO] reviews the proposed portfolios with stakeholders and seeks their comments, which the [CAISO] then considers in determining the final portfolios.[2]

[1] http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf.
[2] CAISO 2018-2019 Board of Governor Approved-Updated Transmission Plan, March 29, 2019, pp. 34.

The Commission and the CAISO have acknowledged the importance of agency coordination in developing and studying the renewable energy portfolios to identify transmission projects. The Commission most recently reiterated this commitment to agency coordination in Decision 19-04-040 in the Integrated Resource Planning (IRP)[3] proceeding, which recommended that the CAISO use the IRP-developed Preferred System Plan in the 2019-2020 Transmission Planning Process.[4]

Further, both the Commission and the CAISO have previously highlighted the development community's need for planning consistency and certainty. Reconsidering portfolios that alter past generation development activities and transmission plans—after the CAISO develops transmission plans and project proponents begin development based on those portfolios—would create an untenable framework for generation developers to site projects and contract with load-serving entities. To encourage cost-efficient renewable procurement, the Commission's annual portfolio development must build on previous years' efforts. In the 2016-2017 transmission planning process, Commission and California Energy Commission (CEC) leaders acknowledged the need for consistency by noting that "[i]t is undesirable to use a renewable portfolio in the [transmission planning process] base case that might require reexamination of previously approved transmission investment decisions."[5]

As noted below, the CAISO identified the need for a correction to the Commission-developed renewable portfolios provided for the 2019-2020 transmission planning cycle, which CAISO uses as the basis for its testimony in this proceeding, specifically in the studies included in the testimony of Mr. Yimer and Mr. Zhang. Waiting for such corrections to find their way through the Commission's portfolio development process is not a practical way to address a straightforward correction identified during the study preparation for CPCN permitting processes for previously approved projects. The

[3] Rulemaking (R.) 16-02-007.
[4] Commission Decision 19-04-040, p. 3.
[5] Page 1, Letter to Steve Berberich from Michael Picker and Robert Weisenmiller http://www.caiso.com/Documents/2016-2017RenewablePortfoliosTransmittalLetter.pdf

CAISO therefore made the appropriate adjustment to provide an accurate representation of need and avoid unnecessary, lengthy and costly delays in the permitting process.

III. CAISO TRANSMISSION PLANNING PROCESS REVIEW AND APPROVAL OF THE PROPOSED PROJECT

Q9. What role did the CAISO's transmission planning process play in determining the need for the Proposed Project?

A9. The CAISO identified the need for the Proposed Project in its 2013-2014 Transmission Plan as necessary to achieve economic benefits for California ratepayers.[6] Specifically, the CAISO found that Proposed Project provided sufficient economic benefits relative to its estimated cost. The CAISO Board of Governors approved the Proposed Project at its June 16, 2014 Meeting.[7]

Q10. Please describe the process by which the CAISO identified and approved the Proposed Project as a necessary economic-driven upgrade.

A10. The CAISO followed its FERC-approved transmission planning process, as generally described above, to review and approve the Proposed Project. The Proposed Project was one of five projects selected for detailed economic study in the 2013-2014 planning cycle, after the project had demonstrated strong benefits in the 2012-2013 transmission planning cycle.

The CAISO studied the Proposed Project considering production cost modeling benefits and forecast transmission line loss savings developed through powerflow analysis. The CAISO also derived system capacity benefits based on then-current forecast of capacity requirements in California and Arizona and the comparative costs of new gas-fired

[6] The CAISO's 2013-2014 Transmission Plan refers to the Proposed Project as the "Delaney-Colorado River 500 kV line." For consistency, my testimony refers to either the Proposed Project or the Ten West Link Project. The CAISO includes excerpts from the 2013-2014 that are relevant to the Ten West Link Project as Attachment A to this testimony.

[7] CAISO 2013-2014 Transmission Plan, http://www.caiso.com/Documents/Board-Approved2013-2014TransmissionPlan_July162014.pdf, p. 268.

generation construction. The CAISO's analysis only considered direct capacity benefits provided by the Proposed Project, *i.e.*, the potential to acquire lower cost capacity for California from either existing surplus or new construction in Arizona. The quantified benefits exceeded estimated costs and, as a result, the CAISO Board of Governors approved the project at its July 16, 2014 meeting.

Q11. Did the 2013-2014 Transmission Plan identify any other potential benefits provided by the Proposed Project?

A11. Yes, the CAISO's 2013-2014 Transmission Plan highlighted several other benefits provided by the Proposed Project. The CAISO did not quantify the economic benefits associated with these impacts, but specifically acknowledged the Proposed Project provided benefits in addition to those quantified in the CAISO's analysis. Those other benefits included:

- Mitigating the impacts of higher contingency flows on neighboring systems—Los Angeles Department of Water and Power's Marketplace-Adelanto 500 kV line in particular—caused by the development of renewable generation in southeastern California and the retirement of gas generation in southwestern California.
- Providing opportunities for CAISO-connected renewable generation to develop in the Delaney area;
- Providing an increase in deliverability from the Imperial Valley zone; and
- Increasing competition in the California generation market.

IV. CAISO SELECTION OF DCRT TO CONSTRUCT AND OWN THE PROPOSED PROJECT.

Q12. Please describe the process by which the CAISO selected DCRT as the Approved Project Sponsor to construct and own the Proposed Project.

A12. As outlined above, after the CAISO identifies and approves needed transmission solutions in Phase 2 of its transmission planning process it then commences a competitive solicitation process in Phase 3 to select an entity to construct and own the new

transmission facilities. The CAISO followed the Phase 3 planning process set forth in the CAISO tariff in selecting DCRT as the Approved Project Sponsor[8] to build the Proposed Project. In my testimony below, I describe and summarize the key events in the competitive solicitation process and the selection of DCRT as the Approved Project Sponsor.

- On August 19, 2014, the CAISO issued a market notice indicating that it had opened a competitive solicitation bid window to receive proposals to build the Proposed Project.
- The CAISO initially received applications to build the Proposed Project from six project sponsors. However, after two parties consolidated their efforts into a single application, the CAISO ultimately received final project sponsor applications from five project sponsors, including DCRT.
- Subsequently, the CAISO determined that the five applicants met the minimum qualifications, as specified in the CAISO tariff, to finance, design, engineer, construct, operate, and maintain the requisite transmission facilities.
- Because the CAISO determined that more than one entity was qualified, it then conducted a comparative analysis of the applicant's proposals pursuant to Section 24.5.4 of the CAISO tariff to select an Approved Project Sponsor to construct and own the Proposed Project.

Q13. Please describe the comparative analysis the CAISO undertook to select DCRT as the Approved Project Sponsor.

A13. As required by the CAISO tariff, the CAISO must select the qualified Project Sponsor that is "best able to design, finance, license, construct, maintain, and operate the particular transmission facility in a cost-effective, efficient, prudent, reliable, and capable manner over the lifetime of the facility, while maximizing overall benefits and minimizing the risk of untimely project completion, project abandonment and future

[8] The CAISO tariff defines an Approved Project Sponsor as "The person or entity designated under the CAISO Tariff to construct, finance and own transmission additions or upgrades."

reliability, operational and other relevant problems, consistent with Good Utility Practice, applicable reliability criteria, and CAISO Documents."[9] The CAISO tariff requires the CAISO to make this selection based on a comparative analysis using the qualification criteria and the eleven specific selection factors described in the tariff.

In conducting the comparative analysis, the CAISO compared the proposals of each qualified Project Sponsor to assess the degree to which each applicant met the qualification criteria and the eleven selection factors, ultimately supporting achievement of the selection standard identified above. The results of the comparative analysis are documented in the Delaney-Colorado River Transmission Line Project-Project Sponsor Selection Report (DCRT Selection Report), which the CAISO posted in July 2015.[10]

Q14. What were the key selection factors that the CAISO used to select DCRT as the Approved Project Sponsor for the Proposed Project?

A14. The CAISO tariff requires the CAISO to identify key selection factors for each competitive solicitation prior to opening a bid window for the solicitation. The CAISO identified the following as the key selection factors for the Proposed Project:

1. The current and expected capabilities of the Project Sponsor and its team to finance, license, and construct the facility and operate and maintain it for the life of the solution;
2. The proposed schedule for development and completion of the transmission solution and demonstrated ability to meet that schedule of the Project Sponsor and its team;
3. Demonstrated cost containment capability of the Project Sponsor and its team, specifically, binding cost control measures the Project Sponsor agrees to accept, including any binding agreement by the Project Sponsor and its team to accept a cost cap that would preclude costs for the transmission solution above the cap from being recovered through the CAISO's Transmission Access Charge, and, if

[9] CAISO Tariff, Section 24.5.4.
[10] http://www.caiso.com/Documents/DelaneyColoradoRiverTransmissionLineProject-ProjectSponsorSelectionReport.pdf.

none of the competing Project Sponsors proposes a binding cost cap, the authority of the selected siting authority to impose binding cost caps or cost containment measures on the Project Sponsor and its history of imposing such measures.

Q15. Please describe how the CAISO selected DCRT as the Approved Project Sponsor for the Proposed Project.

A15. The CAISO determined that DCRT's proposal was superior because the primary selection factor for which the CAISO identified significant differences among the Project Sponsors' proposals was the selection factor with regard to cost containment, particularly the Project Sponsors' commitments to binding cost containment measures. The CAISO concluded that DCRT's proposal provided significant advantages with regard to cost containment and producing materially lower project costs to the benefit of ratepayers.

In the DCRT Selection Report, the CAISO outlined the reasons why it determined that DCRT's cost containment proposal was the most robust.[11]

V. CONTINUING NEED FOR THE PROPOSED PROJECT

Q16. Please describe how the CAISO assessed the continuing need for the Proposed Project for this proceeding.

A16. The CAISO updated its economic analysis for the Proposed Project based on the study assumptions, base cases, and Commission-developed renewable generation portfolios prepared for the 2019-2020 transmission planning process studies that are currently underway. The CAISO assessed both the production cost and capacity benefits associated with the Proposed Project.

[11] *See* DCRT Sponsor Selection Report, p. 131 (accessible at http://www.caiso.com/Documents/DelaneyColoradoRiverTransmissionLineProject-ProjectSponsorSelectionReport.pdf,).

Q17. Does the CAISO's updated analysis consider circumstances arising since the CAISO initially approved the Proposed Project in 2014?

A17. Yes. The CAISO initially approved the Proposed Project based on the parameters and considerations outlined in the 2013-2014 transmission planning process and the CAISO tariff, as they existed at that time. In this proceeding, the Commission must consider the need for the Proposed Project given the evolved circumstances on the electric transmission system.

In addition to the economic benefits set out in the testimony of Mr. Yimer and Mr. Zhang, the Commission should consider other factors that weigh in favor of approving the Proposed Project. Approval and advancement of transmission projects through the CAISO's transmission planning process influences later planning decisions and creates expectations among industry participants that can influence development activities. In an ideal world, transmission project developers would complete siting and permitting activities before subsequent planning decisions need to be made, but the reality is that five annual transmission plans have been completed and approved by the CAISO, and the CAISO has received approximately 580 generation interconnection requests across the CAISO footprint, since initially approving the Proposed Project. Stakeholders, including the generation development community and participants in resource planning proceedings, have moved forward with the best available information, including expectations that DCRT will ultimately construct the Proposed Project and a material number of interconnection requests have been received for interconnection to the CAISO-controlled grid located in Arizona. At this time, there are twelve projects totaling over 6,300 MW active in the CAISO's interconnection queue seeking interconnection to the CAISO-controlled grid in this area, and one recently commissioned, with almost all of those amounts applying in 2015 or later – after the CAISO's approval of the Proposed Project in 2014. Thus, reconsideration of projects in later cycles can have far-reaching implications, especially given the pace of transition in the California electricity industry to non-GHG-emitting resources.

Accordingly, the Commission must consider the broad range of benefits that the Proposed Project provides. The Commission can assess benefits that go beyond those that the CAISO is limited to considering in its transmission planning process. In addition, the Commission should consider the consequences of the Proposed Project *not* proceeding given that it has been part of the transmission and generation planning landscape for the past five years.

Q18. Please explain how the CAISO used the Commission's renewable generation portfolios to study the need for the Proposed Project.

A18. The CAISO, the Commission, and the CEC have established coordinated processes to ensure that there is a common understanding of expectations regarding the development of renewable generation portfolios feeding into the annual transmission planning cycle. However, the timing of CPCN permitting applications and associated proceedings are not part of these coordinated processes. In assessing the need for the Proposed Project for this proceeding, the CAISO identified an issue with the portfolios and specific to the area impacted by the Proposed Project. The CAISO found this issue, if not corrected, would create inconsistencies that stand in the way of comprehensive studies.

Specifically, the CAISO found that the Commission's renewable generation portfolio development process for the portfolios provided to the CAISO for the 2019-2020 transmission planning cycle did not have the opportunity to fully incorporate the growing interest in renewable resource generation development in western Arizona that can be directly connected to the CAISO controlled grid. In that regard, the Commission developed the 2019-2020 renewable generation portfolios erroneously assuming that western Arizona located renewable resources would be connected to non-CAISO facilities. Based on this erroneous assumption, the Commission's portfolio development process excluded western Arizona resources from being selected as intra-CAISO resources and also incorrectly subjected western Arizona renewable generation to import hurdle rates that do not apply to resources directly connected to the CAISO controlled grid facilities, such as the Proposed Project. This modeling error is at odds with the

robust generation development interest expressed in the area, as reflected in the CAISO's interconnection queue and further discussed in Mr. Yimer's testimony.

The CAISO has informed Commission Energy Division staff of this issue for the purpose of refining future portfolios within the Integrated Resource Planning proceeding. In the meantime, this reality should be reflected in assessing the need for the Proposed Project because the proper allocation of renewable generation resources in the desert southwest, and western Arizona in particular, can have potential implications on benefits delivered by the Proposed Project. Accordingly, the CAISO has corrected the error and made limited adjustments to the renewable generation portfolios, using the Commission's capacity expansion modeling software, to produce portfolios that accurately reflect the ability to directly connect western Arizona renewable resources to the CAISO controlled grid. To be clear, the Proposed Project does not cause these changes in renewable portfolios, but rather, the changes are necessary to properly assess the benefits of the Proposed Project.

Q19. Please describe the changes in circumstances that the CAISO took into account in conducting its updated need assessment for the Proposed Project.

A19. The CAISO has re-evaluated the need for the Proposed Project taking into account changes that have occurred since the CAISO's 2014-project approval. The relevant changes include legislative mandates that have affected resource planning and market developments that have occurred in response to the CAISO approving the Proposed Project in 2014.

The CAISO's updated analysis considers the following specific major changes in circumstances that have occurred since the CAISO initially approved the Proposed Project:

- Continued growth of the grid-connected solar in excess of the level anticipated in the 2013 time frame,

- Rapid deployment of distributed energy resources—rooftop solar PV in particular—far exceeding industry expectations;
- Decreasing battery storage costs;
- Actual and forecast reductions in the out-of-state thermal fleet, including out-of-state coal resources;
- Legislation requiring load-serving entities to acquire 60% of their energy from renewable resources by 2030 and 100% of energy from non-GHG-emitting generation by 2045;
- Broader acceptance that natural gas resources will be critical to ensure reliability well into the future—with those resources providing a key source of dispatchable capacity but far less overall energy production;
- Advancement of generation and transmission planning and development processes. In particular, the impact of the Proposed Project being part of the planning landscape over the last five years, which is demonstrated by the significant generation development activity in the western Arizona area and generation projects seeking direct connection to the CAISO-controlled grid through points of interconnection located in Arizona.

Q20. Please describe the Proposed Project's economic benefits as identified in the CAISO's updated analysis.

A20. The concurrently served testimony of Mr. Yi Zhang and Mr. Nebiyu Yimer provide updated economic analysis demonstrating the economic benefits of the Proposed Project. I have summarized the key aspects of their testimony below.

Mr. Yimer's testimony assesses the capacity benefits associated with the Proposed Project, specifically the creation of 969 MW of additional deliverable capacity for solar resources. Mr. Yimer calculates the economic benefit that this additional deliverable capacity using several methodologies to ensure the reasonableness of his results.

Mr. Zhang's testimony addresses the forecast production cost modeling savings attributable to the Proposed Project. Mr. Zhang combines these savings with capacity procurement savings calculated by Mr. Yimer to conduct a benefit-to-cost ratio analysis of the Proposed Project under various sensitivities. Mr. Zhang's analysis shows that the Proposed Project results in CAISO ratepayer benefits in excess of the most up-to-date project cost estimates.

In addition to the economic benefits calculated by the CAISO, the Proposed Project provides additional potential benefits in meeting overall resource adequacy and energy needs in an increasingly uncertain future. The Proposed Project provides additional transmission capacity to the southwest, improving interregional opportunities for diversity benefits of sharing resources. The value of strengthened ties to neighboring balancing authorities should not be downplayed notwithstanding the fact that it is difficult to assign a specific dollar value to this benefit.

Q21. Please explain the importance of the deliverability methodology Mr. Yimer uses in his capacity saving analysis.

A21. Mr. Yimer uses the CAISO's current deliverability methodology to assess if there is sufficient transmission such that resources can reasonably deliver output to load during times of high system need. A resource must be deliverable, and must have Full Capacity Deliverability Status,[12] to count toward load-serving entity resource adequacy needs. The capacity benefits calculated by Mr. Yimer rely on the CAISO's deliverability analysis to determine the incremental MW quantity of solar resources that will be deliverable if the Proposed Project is built. Using the CAISO's current deliverability methodology to assess the benefits provided by the Proposed Project is appropriate given the

[12] The CAISO tariff defines "Full Capacity Deliverability Status" as a status that "entitles a Generating Facility to a Net Qualifying Capacity amount that could be as large as its Qualifying Capacity and may be less pursuant to the assessment of its Net Qualifying Capacity by the CAISO."

circumstances of this case. Furthermore, the Commission recently recognized the need for additional system resource adequacy capacity by directing load-serving entities to procure an incremental 3,300 MW "as a 'least regrets' amount necessary to ensure system reliability."[13]

VI. ESTIMATE OF PROPOSED PROJECT COSTS

Q22. Please explain the basis for the CAISO's estimated costs of the Proposed Project.

A22. The cost estimates that the CAISO relied upon to estimate the benefit-to-cost rate for the Proposed Project are the most recent estimates provided by DCRT. The CAISO notes that these cost estimates result in total project costs very similar to the cost estimates upon which the Proposed Project was originally approved. Further, these estimates may differ from the costs provided in DCRT's competitive solicitation proposal due to projected costs increases that DCRT considers to be outside of the binding cost cap commitments made in the competitive solicitation process. The final determination regarding cost recovery rests with FERC and will be considered when DCRT files its revenue requirement application. The CAISO does not express an opinion on potential FERC cost recovery issues at this time. Instead, the CAISO has conservatively assessed benefit-to-cost ratios based on the cost estimates provided by DCRT.

Q23. Do the benefits of the Proposed Project exceed the estimated costs of the Project?

A23. Yes. Based on the most recently available cost information provided by DCRT in its application, the Proposed Project continues to show projected benefits exceeding annualized revenue requirement costs.

[13] *See* Commission Decision 19-11-016, p. 70, Finding of Fact No. 16.

VII. CONCLUSION

Q24. Based on the CAISO's most recent analysis, is the Proposed Project still necessary?

A24. Yes. The Proposed Project continues to provide economic benefits that exceed its estimated costs and, as a result, is necessary under the CAISO tariff. The testimony of Mr. Yimer and Mr. Zhang provide the CAISO's updated analysis demonstrating the continued need for the Proposed Project.

Q25. Please summarize your recommendations.

A25. As explained in my testimony and the supporting technical testimony of Mr. Yimer and Mr. Zhang, the Proposed Project is necessary to meet policy requirements of the State of California. As a result, I recommend that the Commission approve the Application filed by Southern California Edison for a certificate of public convenience and necessity for the Proposed Project.

Q26. Does this conclude your testimony?

A26. Yes, it does.

ATTACHMENT A

TESTIMONY OF NEIL MILLAR

California ISO
Shaping a Renewed Future

July 16, 2014

Prepared by: Infrastructure Development
Approved by: ISO Board of Governors

5.7.4 Delaney – Colorado River 500 kV line

This section describes the economic planning study of building a new Delaney – Colorado River 500 kV line.

5.7.4.1 *Congestion analysis*

Table 5.7-16 lists simulation results of congestion hours before and after adding the proposed the Delaney – Colorado River 500 kV line for the facilities that were identified as congested in Table 5.6-1.

Table 5.7-16: Congestion hours before and after adding the Delaney – Colorado River 500 kV line

#	Transmission Facilities	Year 2018		Year 2023	
		Before	After	Before	After
1	Path 66 (COI) nomogram	3	1	-	-
2	Path 25 (PacifiCorp – PG&E 115 kV Interconnection)	488	510	651	660
3	Contra Costa Sub – Contra Costa 230 kV line	4	7	15	18
4	US Wind Power – JRW – Cayetano 230 kV line, subject to loss of Contra Costa – Las Positas 230 kV line	-	-	1	1
5	Midway – Vincent 500 kV line #1 or #2	1	-	4	3
6	Midway – Vincent 500 kV line #1, subject to loss of #2 line, or vice versa	69	61	28	32
7	Midway – Vincent 500 kV line #1 or #2, subject to loss of Midway – Whirlwind line	111	85	37	30
8	Path 26 (Northern – Southern California)	692	621	468	420
9	Path 26 north-to-south Operating Transfer Capability	5	1	8	7
10	Vincent 500/230 kV transformer #1	6	5	4	3
11	Villa Park – Lewis 230 kV line, subject to loss of Villa Park - Barre 230 kV line	2	5	-	-
12	Lewis – Barre 230 kV line, subject to loss of Villa Park – Barre 230 kV line	70	104	-	-
13	Barre - Ellis 230 kV line, subject to loss of Hassayampa – North Gila 500 kV lines	2	-	-	-

#	Transmission Facilities	Year 2018		Year 2023	
		Before	After	Before	After
14	Litehipe – Hinson 230 kV line, subject to loss of La Freso - Redondo 230 kV line	3	5	-	-
15	Julian Hinds – Mirage 230 kV	83	2	7	-
16	Kramer – Lugo 230 kV line #1 and #2	623	584	85	77
17	Inyo 115 kV phase shifter	769	733	760	749
18	Control – Inyokern 115 kV line #1	-	-	34	35
19	Control – Tap710 115 kV line	-	-	458	464
20	Miguel 500/230 kV transformer #1, subject loss of transformer #2	-	-	1	-
21	SCIT limits	23	-	2	-

Figure 5.7-12 shows the topology of the interconnected system of Nevada, Arizona and Southern California. The figure is a simplified system diagram derived from with the proposed Delaney – Colorado River 500 kV line marked as “D-CR” explains the simulation results shown in Figure 5.7-13.

Figure 5.7-12: 500 kV transmission connections
between Nevada/Arizona and Southern California ISO system

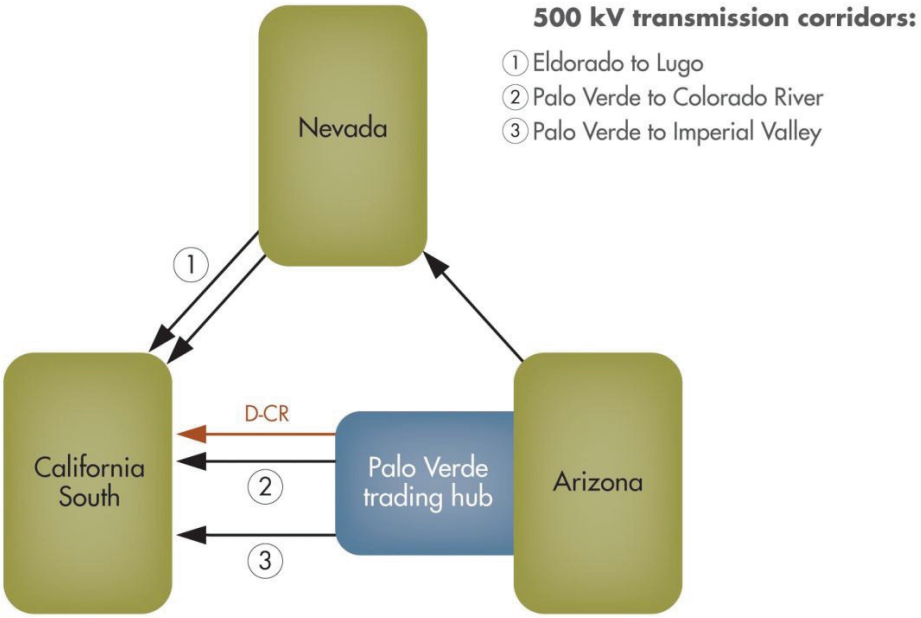


Figure 5.7-13 shows simulation results of energy transfer from Nevada to Southern California and from Arizona to California via 500 kV transmission lines. Each bar is a 365 day accumulation of energy for each hour. It shows the Southern California import is heavily distributed on the Nevada – California transmission corridor and that the Palo Verde – Colorado River transmission corridor carries less power. Even the North Gila – Imperial Valley transmission corridor carries more power than the Palo Verde – Colorado River corridor. Adding the new Palo Verde – Colorado River 500 kV line provides Southern California with more direct access to efficient generation at Palo Verde Trading Hub and APS system.

Figure 5.7-13: Energy transfer from NV and AZ to CA via 500 kV ties with addition of the Delaney – Colorado River 500 kV line

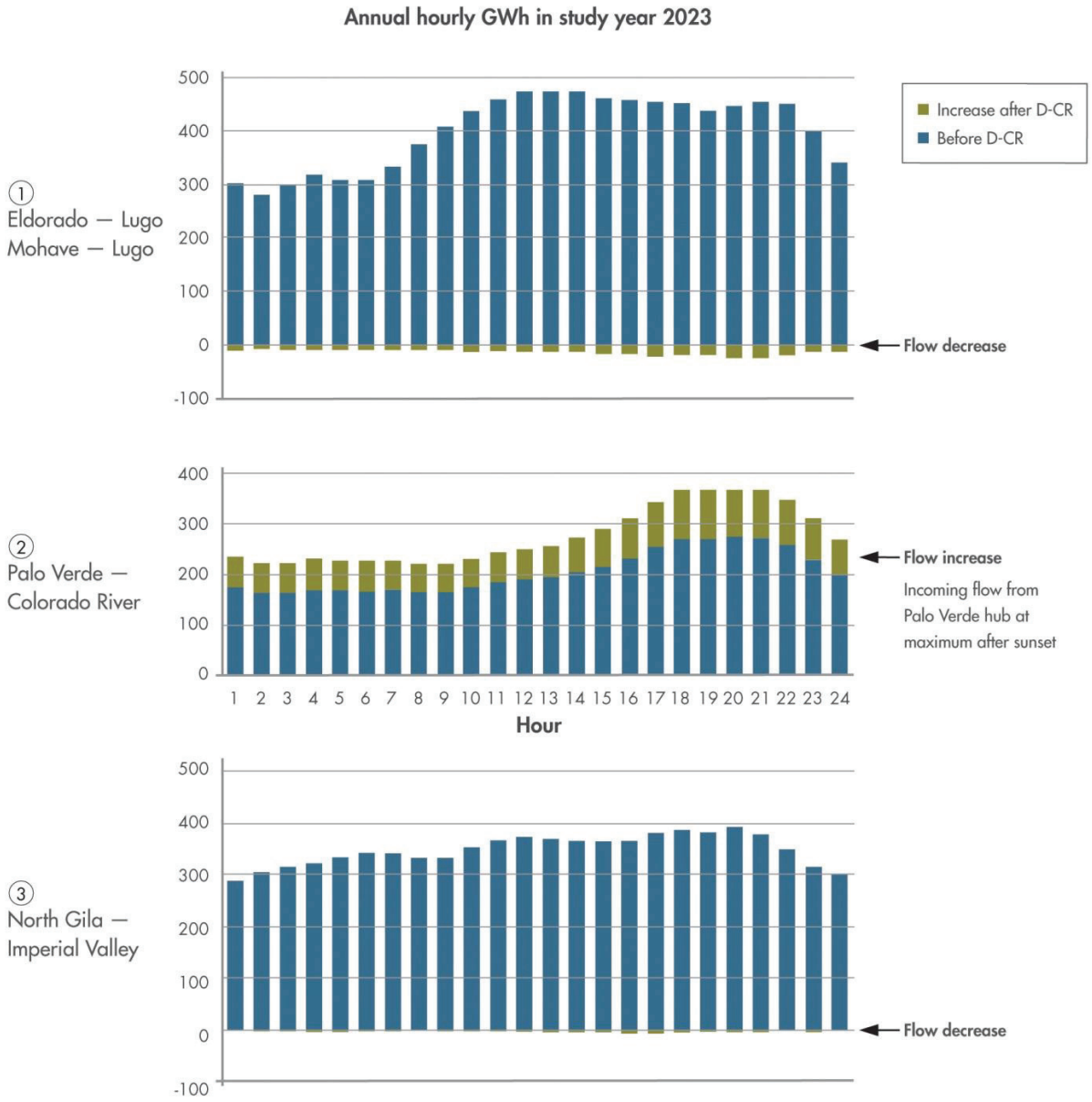
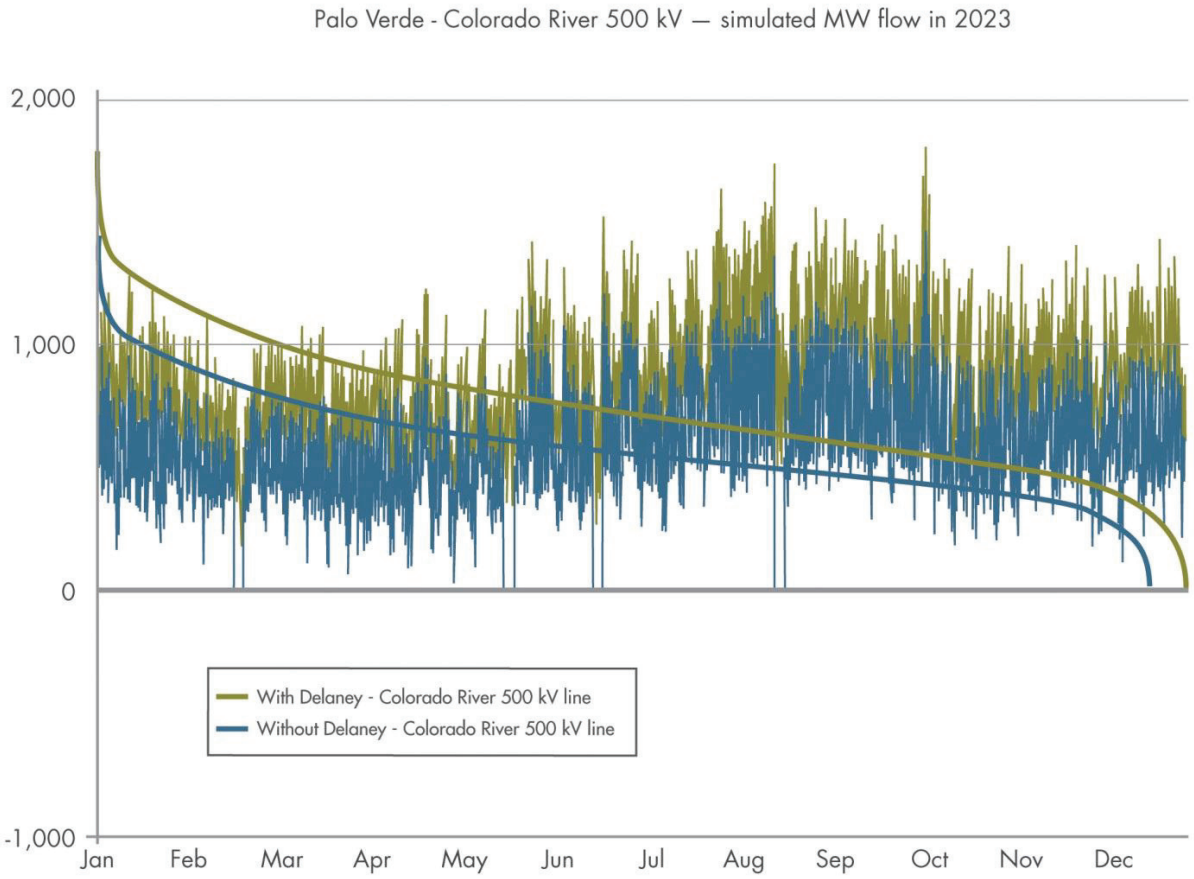


Figure 5.7-14 shows simulation results of 500 kV transmission flows from Palo Verde to Colorado River.

Figure 5.7-14: Line flows from Palo Verde to Colorado River with addition of the Delaney – Colorado River 500 kV line



The Delaney – Colorado River 500 kV line allows SCE area to:
1. Have more efficient access to the Palo Verde trading hub
2. Have uninterrupted access to the Palo Verde hub under L-1 conditions
3. Receive 30% more dispatched energy via this transmission corridor

5.7.4.2 *Impacts to dispatch and LMP*

Figure 5.7-15 shows generation dispatch changes with addition of the Delaney – Colorado River 500 kV line. The line will facilitate more use of efficient generation at the line's sending end (the Palo Verde trading hub and APS area). Generation increase at Palo Verde and APS displaces more expensive generation at the receiving end (SCE, SDG&E and PG&E areas).

Figure 5.7-15: Generation changes with addition of the Delaney – Colorado River 500 kV line

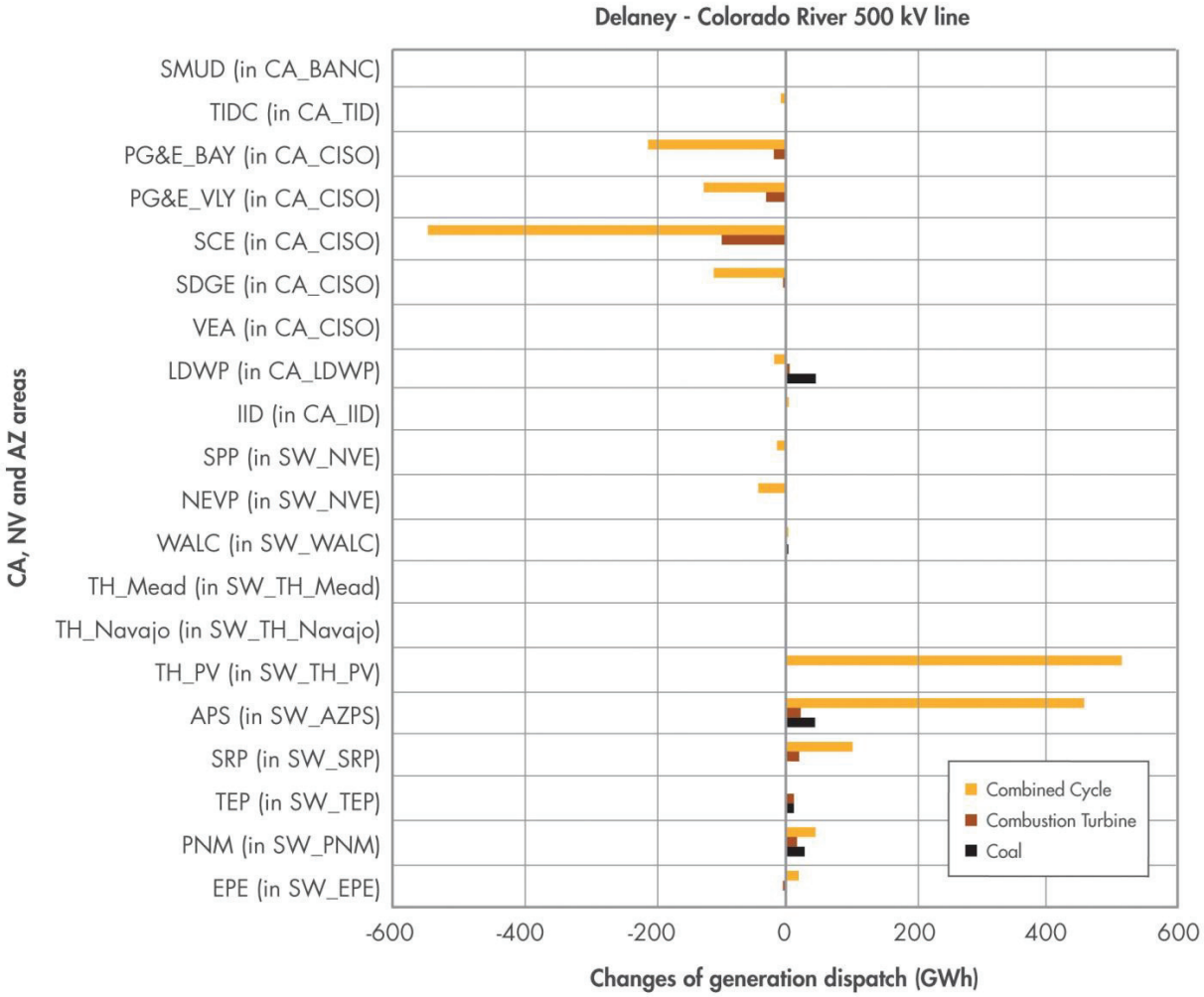
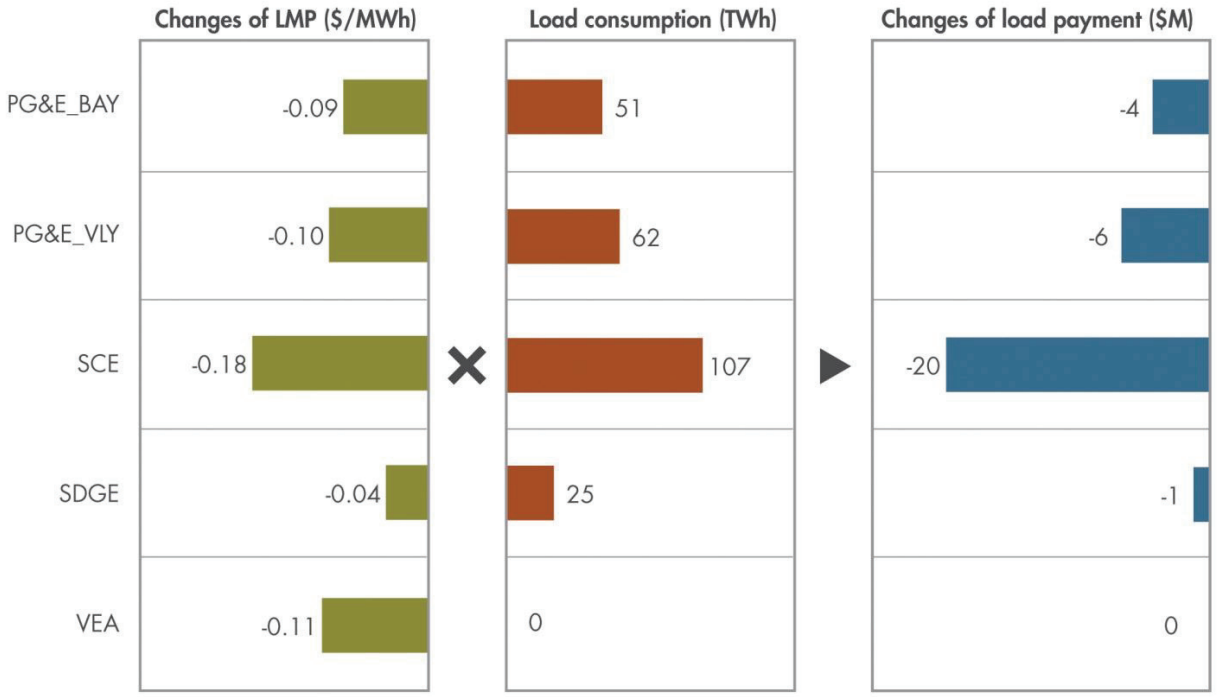


Figure 5.7-16 shows the resulting changes of LMP and load payments. It can be seen that with the addition of the Delaney – Colorado 500 kV line reduces LMP in the ISO-controlled grid. The LMP reduction leads to load payment reduction in the SCE, SDG&E, PG&E, and VEA areas and benefits to their ratepayers in total (ISO ratepayers). The SCE area sees the largest load payment reduction.

Figure 5.7-16: LMP and load payment changes with addition of the Delaney – Colorado River 500 kV line



Simulation year 2023
The "Changes of LMP ($/MWh)" is the difference of annual averages

5.7.4.3 *Production benefits*

Based on 8,760 hourly production simulations for the study years, yearly ISO ratepayer benefits are calculated as $26 million in 2018 and $17 million in 2023, respectively. In addition, we estimated losses reduction benefit outside the production simulation model using a traditional power flow calculation. In this case, the losses reduction benefit is estimated as $1 million per year. Table 5.7-17 lists quantified yearly production benefits.

Table 5.7-17: Yearly production benefits of building a new Delaney – Colorado River 500 kV line

Yearly production benefit			
Year	**Production benefit calculated by production simulation**	**Losses reduction benefit estimated outside the production simulation model**	**Sum**
2018	$26M	$1M	$27M
2023	$17M		$18M

Table 5.7-18 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 5.7-18: Breakdown of yearly production benefits computed by production simulation

Year	Production benefit calculated by production simulation	Consumer benefit	Producer benefit	Transmission benefit
2018	$25.6M	$30.3M	($4.1M)	($0.7M)
2023	$17.0M	$21.7M	($3.4M)	($1.3M)

5.7.4.4 *Capacity benefits*

The system RA benefits are calculated as 200 MW to 300 MW of incremental import capacity multiplied by capacity cost differences between California and Arizona. 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 Delaney – Colorado River 500 kV line project. The WECC path rating for WOR is 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 overloads on the Suncrest – Sycamore 230 kV lines and the Imperial Valley – ECO – Miguel 500 kV lines. These overloads are caused by imports from Arizona, Nevada, and IID and existing and new generation dispatch in southwestern California. Adding the Delaney – Colorado River 500 kV line to the system incrementally relieves these overloads and allows approximately 200 MW to 300 MW of incremental import capability. The variation from 200 MW to 300 MW is due to the uncertainty in the Sycamore – Suncrest 230 kV line ratings, and the assumed operation of the Imperial Valley to CFE flow control device. The 300 MW increase is the result when the Sycamore- – Suncrest line is the limiting facility and the 200 MW increase is the result when the ECO-Miguel 500 kV line is the limiting facility due to a higher Sycamore – Suncrest line rating or higher flows on the Imperial Valley to CFE flow control device are assumed.

The Delaney – Colorado River (D-CR) planning capacity benefits calculation is based on the following primary assumptions, which are further explained below:

1. California will be resource deficit by 2020;
2. Arizona will resource deficit by 2025;
3. Arizona peaking units can be built and operated at a lower cost than California peaking units; and
4. The incremental capacity available with the addition of the D-CR line is approximately 200 MW to 300 MW available starting in 2020.

California Resource Deficiency

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).[40] 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 shortage while the replicating TPP scenario showed a 4,000 MW to 5,000 MW shortage[41]. 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 Arizona — either due to Arizona'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 very significant.

Arizona Resource Deficiency

The WECC Desert Southwest sub-region is forecast to be resource surplus until 2025.[42] The NERC "2012 Long-Term Reliability Assessment" projects an anticipated planning reserve margin of 29.1 percent in 2022 (the last year of the NERC assessment).[43] 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 5.7-19 below:[44] 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.

[40] California Independent System Operator, "Review of Scenario Assumptions and Deterministic Results", CPUC LTPP Track 2 Workshop, August 26 2013, Dr. Shucheng Liu, Principal in Market Development, page 29, "Upward Ancillary Services and load following shortages".
[41] 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.
[42] 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.
[43] NERC LTRA, "WECC Subregional Tables", Planning Reserve Margins WECC DSW (Desert Southwest), p. 255/355.
[44] NERC LTRA, "Demand Outlook WECC-DSW", p. 257/355.

Table 5.7-19: Summary of DSW 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 AZ Capacity

The cost of capacity from peaking units in California is forecast to be $41/kw-year more than the comparable annual cost in Arizona in 2012 dollars. 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 AS 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.[45]

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.[46] These flexible units will be needed as more intermittent renewable generation is added to the system. The California industrial frame-type CT capital and fixed O&M cost is derived from the ISO 2012 Annual Report on Market Issues and Performance and is $155/kw-yr and $35/kw-year, respectively, in 2012 dollars.[47] The California industrial frame CT capital cost then was increased by 44 percent to represent an aero-derivative combustion turbine cost.[48] This resulting annual capital cost is then increased by fixed O&M, reduced for energy and AS net revenue and adjusted for summer

[45] 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.
[46] CEC "Status of all Projects", www.energy.ca.gov/sitingcases/all-projects.html.
[47] ISO "2012 Annual Report on Market Issues and Performance", Department of Market Monitoring, Table 1.9 "Assumptions for a typical new combustion turbine
[48] "Cost and Performance Review of Generation Technologies", prepared for WECC by E3, October 9 2012, Table 37, p. 69. The on line total capital cost of aero-derivative and frame CTs are $1,150/kw and $850/kw, respectfully, a 44 percent increase.

peak derate. The resulting net cost of California capacity when resource deficit is $208/kw-year in 2012 dollars. This information is summarized in Table 5.7-20.

Table 5.7-20: Derivation of CA net capacity costs in 2012 $

Parameter	Value	Units	Source / Notes
CA resource deficit year	2020	Year	2012 NERC LTRA
CA industrial capital cost	$155	$/kw-yr	2012 ISO Annual Report on Market Issues and Performance
CA aero/industrial increase	44%	Percent	WECC Generation Costs
CA aero capital cost	$223	$/kw-yr	Product of capital cost and aero increase
CA CT fixed O&M	$35	$/kw-yr	2012 ISO Annual Report on Market Issues and Performance
CA SP15 energy/AS rev.	$60	$/kw-yr	2012 ISO Annual Report on Market Issues and Performance
CA aero annual fixed costs	$198	$/kw-yr	Capital plus FOM minus net rev.
Summer peak-hour derate	5%	Percent	Assumption
CA aero net annual fixed cost	$208	$/kw-yr	Aero annual cost divided by 95% (i.e. summer peak derate)

Arizona'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 5.7-21 below:

Table 5.7-21: Derivation of AZ net capacity costs in 2012 $

Parameter	Value	Units	Source / Notes
AZ resource deficit year	2025	Year	2012 NERC LTRA
AZ aero total fixed costs	$210	$/kw-yr	WECC Generation Costs
AZ energy / AS rev.	$54	$/kw-yr	Assumption (90% of SP15)
AZ net aero fixed costs	$156	$/kw-yr	before derate
Summer peak-hour derate	5%	Percent	assumption (same as CA)
AZ net aero fixed costs	$164	$/kw-yr	Aero annual cost divided by 95% (i.e. summer peak derate)

In a 2012 WECC document, CT capital and fixed costs are compared 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.[49]

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 $210/kw-year. This cost is decreased by the assumed Arizona energy/AS revenue[50] and increased due to the summer peak derating of 5 percent. The resulting net cost of Arizona new resource capacity is $164/kw-yr in 2012 $, or $44/kw-year less than California capacity.

The Desert Southwest is not projected to become resource deficit until 2025. Prior to that time the capacity market prices there would prevail for the incremental capacity purchases over the D-CR 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 $20/kw-year in 2012 (2012 $) is a reasonable current market price estimate. The assumed market price for 2012 is then linearly increased each year to the net cost of an Arizona aero CT in 2025. These annual estimates are summarized in Table 5.7-22 as well as the computed annual benefit.

[49] "Cost and Performance Review of Generation Technologies – Recommendations for WECC 10- and 20-Year Study Process", WECC, Table 40, Technology-regional cost multipliers (technology-specific multipliers apply to capital costs; fixed O&M multiplier applies to fixed O&M for all technologies, p. 75.

[50] 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 5.7-22: Annual capacity benefit (2012 $) based on 200 MW Increase in WOR

Year[51]	AZ Market Price ($/kw-yr)[52]	AZ CT Cost ($/kw-yr)	SP15 CT Cost ($/kw-yr)	CAISO Capacity Benefit ($/kw-yr)	CAISO Capacity Benefit (mil. $)
2012	$20				
2013	$31				
2014	$42				
2015	$53				
2016	$64				
2017	$76				
2018	$87				
2019	$98				
2020	$109		$208	$99	$20
2021	$120		$208	$88	$18
2022	$131		$208	$77	$15
2023	$142		$208	$66	$13
2024	$153		$208	$55	$11
2025	$164	$164	$208	$44	$9
2026		$164	$208	$44	$9
2027-2069		$164	$208	$44	$9

Although the D-CR transmission upgrade is assumed to have a 50-year economic life, only the first eight years of capacity benefits are shown in this table. The annual capacity value is $9 million per year in 2012 dollars from 2025 through 2069, assuming that the CT costs and market

[51] This economic study originated in 2012. Hence, the first year for projected market prices is 2012 and not a later year.
[52] Arizona market prices are interpolated between 2012 and 2025 when the Arizona market price is equivalent to the annual CT costs.

prices have a zero real escalation rate. The levelized ISO capacity benefit is $11 million per year in 2012 dollars.[53]

Table 5.7-23: Yearly capacity benefits of building a new Delaney – Colorado River 500 kV line

Year	System RA benefit 200 MW	System RA benefit 300 MW
2018	0	0
2019	0	0
2020	$20M	$30M
2021	$18M	$26M
2022	$15M	$23M
2023	$13M	$20M
2024	$11M	$16M
2025	$9M	$13M

Other Benefits

In addition to the quantified economic benefits, the Delaney – Colorado River 500 kV line provides incremental reliability benefits as well. As shown in Chapter 4, the common corridor outage of the Lugo – Mohave and Lugo – Eldorado 500 kV lines results in overloads on the Lugo –Victorville 500 kV and Marketplace – Adelanto 500 kV lines. The addition of the Delaney – Colorado-River 500 kV line would mitigate the overload on the Marketplace – Adelanto 500 kV line and would incrementally reduce the loading on the Victorville – Lugo 500 kV line by about 8 percent. Although this common corridor outage has an exception from WECC and is considered a Category D contingency, the impacts of the outage on neighboring systems should not be allowed to grow unbounded. Therefore, a safety net generation dropping scheme is being implemented that will mitigate the impacts of the highest impact new generation, but Delaney – Colorado River can incrementally mitigate the impacts of higher contingency flows on neighboring systems caused by the development of generation in southeastern California and the retirement of generation in southwestern California.

The above capacity analysis is based on the conservative assumption that the capacity benefits are achieved through generation connected to transmission systems outside of the ISO controlled grid. However recent initiatives have created the opportunity for new generation to

[53] The levelized cost is the product of the present value of annual values (benefits or costs) multiplied by the appropriate capital recovery factor.

connect to the Hassayampa 500 kV bus and still be within the ISO BAA. In addition, the Delaney-Colorado River transmission line would be expected to create the opportunity for new generation to connect to Delaney 500 kV bus and still be within the ISO BAA. Generation inside the ISO BAA and connected to the ISO Controlled Grid has seamless access to the ISO transmission, and studies of capacity benefits for such generation would be based on the ISO's generation interconnection deliverability methodology which is designed for generation inside the ISO BAA and connected to the ISO Controlled Grid. Quantifying the capacity benefits of the Delaney-Colorado River 500 kV line utilizing the ISO's generation interconnection deliverability methodology based on the assumption that new Arizona generation is connected to the ISO Controlled Grid would result in capacity benefits higher than noted above.

Delaney-Colorado 500 kV line also provides policy benefits, as it can help improve the deliverability from the Imperial Valley renewable energy zone, as discussed in Section 4.3. These benefits were quantified based on the ISO's generation interconnection deliverability methodology. Utilizing the benefits of the Delaney-Colorado River line to increase deliverability from the Imperial Valley zone may result in trading off to some extent the capacity benefits quantified in this analysis. In addition, this use would presumably be considered of higher value for that to occur, which would therefore result in a higher overall benefit than attributed through the analysis examining conventional resource alternatives.

5.7.4.5 *Cost estimates*

For the proposed Delaney – Colorado River 500 kV line, the capital cost is estimated as $325 million in 2012 dollars. The total cost (revenue requirement) is estimated at $469 million to $560 million using financial calculations based on assumptions described in Section 5.5 and for sensitivity purposes, with a 10% return on equity, 5% discount rate, and Arizona state tax rate. The cost estimates are listed in Table 5.7-24.

Table 5.7-24: Cost estimates for the proposed Delaney – Colorado River 500 kV

NPV of annualized revenue requirement, 2012 constant dollars		
	5% Real Social Discount Rate	7% Real Social Discount Rate
10% ROE, 7% state tax	530 million	442 million
11% ROE, 8.84% state tax	560 million	469 million

5.7.4.6 *Cost-benefit analysis*

Based on yearly benefits calculated above, the total benefit is calculated in the present value using both a 7 percent and a 5 percent social discount rate, and the using the cost ranges calculated above, benefit-cost ratio ranges are also calculated as shown in Tables 5.7-25 and 5.7-26.

Table 5.7-25: Cost-benefit analysis of the proposed Delaney – Colorado River 500 kV

7% discount rate	**Capacity Benefit**	
	200 MW	**300 MW**
Total benefit ($M)	406	477
Total cost ($M)	442-469	442-469
Benefit-cost ratio	.87-.93	1.02-1.09

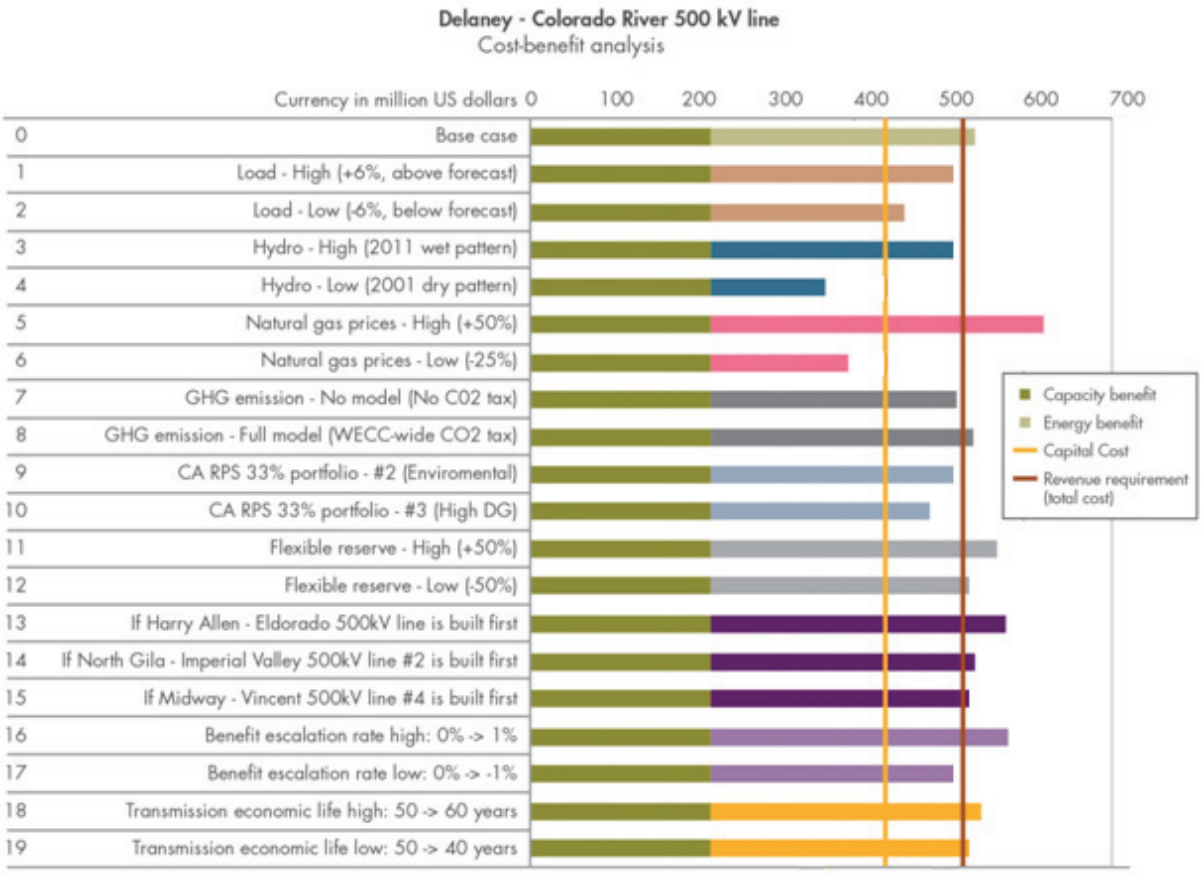
Table 5.7-26: Cost-benefit analysis of the proposed Delaney – Colorado River 500 kV

5% discount rate (sensitivity)	**Capacity Benefit**	
	200 MW	**300 MW**
Total benefit ($M)	528	617
Total cost ($M)	530-560	530-560
Benefit-cost ratio	.95-1.0	1.11-1.17

5.7.4.7 *Sensitivity analyses*

Figure 5.7-17 graphically shows the sensitivity of the economic benefits of the Palo Verde – Colorado River 500 kV line. Production benefits were calculated in a sensitivity analysis under different varied assumptions. For simplicity, the net present values of the production simulation benefit, capacity benefit, and revenue requirement were calculated for the two import transfer capability levels and the different financial parameters shown above and then averaged. It was also assumed that the relative differences from sensitivity results would not significantly change for limited subsequent updates to the model.

Figure 5.7-17: Sensitivity analyses



5.7.4.8 *Recommendation*

The Delaney – Colorado River 500 kV[54] line is recommended for approval in this transmission plan, based on:

- Sufficient economic benefits demonstrated relative to the estimated cost of the project. Sensitivity analyses also showed economic benefits under a majority of assumptions and uncertainties,
- Potential for policy benefits in increasing the deliverability from the Imperial Valley area, and,
- Reliability benefits in reducing flows on key transmission paths.

The economic justification for the project is dependent on its estimated cost, and as a result cost estimates and cost management information provided by project sponsors will be carefully considered with respect to the estimated cost assumed in the ISO's economic analysis.

[54] The Delaney-Colorado River 500 kV line was approved by the ISO Board of Governors at the July 16, 2014 ISO Board meeting.