PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

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Ratesetting

TO PARTIES OF RECORD IN APPLICATION 16-10-012:

This is the proposed decision of Administrative Law Judge Daphne Lee. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's November 4, 2021 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, *ex parte* communications are prohibited pursuant to Rule 8.2(c)(4).

/s/ ANNE E. SIMON
Anne E. Simon
Chief Administrative Law Judge

AES:mph
Attachment

Decision **PROPOSED DECISION OF ALJ LEE (Mailed 10/1/2021)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

DECISION GRANTING DCR TRANSMISSION, LLC A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE TEN WEST LINK PROJECT

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DECISION GRANTING DCR TRANSMISSION, LLC A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE TEN WEST LINK PROJECT

Summary

This decision grants DCR Transmission, LLC (DCRT) a certificate of public convenience and necessity (CPCN) for the Ten West Link Transmission Line Project, to construct a 125-mile, series-compensated 500 kilovolt transmission line with a conductor capacity of approximately 3200 megawatts between the Colorado River 500 kilovolt substation, owned by Southern California Edison Company, and Delaney 500 kilovolt substation, owned by Arizona Public Services Company.

This CPCN is conditioned upon DCRT's compliance with (a) the Mitigation Monitoring and Reporting Plan attached to this decision; (b) the Electric and Magnetic Fields Field Management Plan, filed as Appendix F to Application 16-10-012; (c) the Applicant's Proposed Measures for Safety and the Bureau of Land Management's Required Best Management Practices, attached as Appendix 2A of the FEIS; and (d) all other necessary state and local permitting processes and approvals.

This decision also certifies that the FEIS satisfies the requirements under National Environmental Policy Act and California Environmental Quality Act and concludes the maximum reasonable and prudent cost for the Ten West Link Transmission Line Project is $389,045,968 in 2021 dollars, including contingency, subject to the Commission's authority to review actual costs incurred for reasonableness and prudency and to challenge them as appropriate at the Federal Energy Regulatory Commission.

Lastly, this decision:

(a) authorizes DCRT to file the FERC Forms 1 and 3-Q as proxies to meet the requirements of General Orders (GOs) 65-A and 104-A;

(b) denies DCRT's requested exemption from the reporting requirements under GO 77-M; and

(c) grants DCRT limited exemption from the sections V.C., V.E. and V.G. of the Affiliate Transaction Rules.

This proceeding is closed.

1. Background

1.1. Proposed Project Description

Ten West Link Transmission Line Project is a proposed 125-mile 500 kilovolt (kV) single-circuit, series-compensated, transmission line project (Proposed Project). The California Independent System Operator (CAISO) Board, in the 2013-2014 Transmission Planning Process (TPP), approved the Proposed Project to provide economic benefits for California ratepayers.[1] The Proposed Project will span between the Delaney Substation (located just north of the Palo Verde generating plant in Tonopah, Maricopa County, Arizona) and the Colorado River Substation (located west of the Arizona-California border in Riverside County, California).

The Delaney Substation is owned and operated by Arizona Public Service (APS) and connected to the Palo Verde-Hassayampa Common Bus. The Colorado River Substation is owned and operated by Southern California Edison (SCE) and connected at the 500 kV bus.

[1] *Opening Brief of the California Independent System Operator Corporation*, filed February 12, 2021 (CAISO Opening Brief), at 1. *See also, Application of DCR TRANSMISSION, LLC for a Certificate of Public Convenience and Necessity for the Ten West Link Project* (Application), Appendix M.

Spanning approximately 103.5 miles in Arizona and 21.5 miles in California, the proposed route of the Proposed Project largely follows the existing Devers-Palo Verde (DPV) 500 kV transmission line and utilizes the established utility corridor, crossing Federal land, including lands managed by the Bureau of Land Management (BLM), Bureau of Reclamation (Reclamation), and the United States Army, Yuma Proving Ground (YPG).[2]

The Proposed Project will have a conductor capacity to transmit 3,200 megawatt (MW) and provide interconnection capability for new energy projects located in the region.[3] Once the Proposed Project is constructed and energized, DCRT intends to establish a second contiguous 500 kV transmission connection from the Palo Verde trading hub in Arizona to the Devers substation in Southern California.

The Proposed Project construction includes:

1. Installation of a single 500 kV transmission circuit supported by a combination of self-supporting and guyed galvanized steel lattice towers, and
2. Construction of a new series compensation substation (SCS), to be located within the 200-foot-wide right of way (ROW) parallel to the existing SCS associated with the DPV transmission line, approximately 47 miles from the APS Delaney Substation.[4]

The proposed transmission structures will comprise of steel lattices of various configurations[5] and between 72 and 195 feet in height, depending on the span length required and topography, with most being shorter than 142 feet.

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[2] Record of Decision (ROD), November 22, 2019, at 2.

[3] Final Environmental Impact Statement (FEIS), Executive Summary, at ES-1.

[4] A detailed description of Project facilities is found in Application under Appendix A.

[5] FEIS, Executive Summary, at ES-5-ES-6.

Span lengths between structures would vary from 400 to 2,300 feet, depending upon terrain conditions, current land use, structure type, and site-specific mitigation objectives. Since the new SCS will be in Arizona, this decision focuses on the proposed transmission lines located within California, in the context of the overall Proposed Project.

The CAISO's 2013-2014 economic evaluation projected the benefit-to-cost ratio (BCR) for the Proposed Project to range from 1.16 to 1.54 in the baseline analysis using the avoided cost of battery storage to quantify capacity benefits.[6] In the higher gas price sensitivity, the range of BCR increased from 1.48 to 1.89 using the same avoided cost of battery storage to quantify capacity benefits.[7] Using the locational renewable cost savings to calculate capacity benefits, the CAISO projected the BCR to range from 1.00 to 1.56.[8] Overall, the CAISO concluded in each of the differing scenarios that the Proposed Project would consistently produce positive BCR, even after heavily discounting the potential capacity benefits.

In July 2015, the CAISO selected DCRT, as the approved project sponsor for the Proposed Project, to develop, permit, design, finance, build, own, operate and maintain the Proposed Project in accordance with the CAISO tariff. DCRT and CAISO entered into the Approved Project Sponsor Agreement (APSA) on December 1, 2015.[9]

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[6] Exhibit (Exh.) CAISO-01, *Testimony of Yi Zhang on Behalf of the California Independent System Operator Corporation* (Zhang Opening Testimony), at 10, Table 4.

[7] *Id*. at 11, Table 5.

[8] *Id*. at 12-13, Tables 6 and 7.

[9] Application, Appendix N.

DCRT is a limited liability company organized under the laws of Delaware and a joint venture between Starwood Energy Group (Starwood Energy) and Atlantica Yield PLC (Atlantica).[10] Starwood Energy, through its affiliates, is the managing member of DCRT with an 87.5% majority ownership interest. Atlantica holds a 12.5% minority ownership interest.[11]

Starwood Energy, an affiliate of private real estate investment firm Starwood Capital Group, specializes in energy infrastructure investments, with a focus on the transmission, renewable power generation, and natural gas sectors.[12] Through its general opportunity funds and other affiliated investment vehicles, Starwood Energy manages more than $2 billion in total equity commitments with transactions totaling more than $4 billion in enterprise value. Starwood Energy developed, constructed, and owned two major transmission projects: 1) the Neptune Regional Transmission System, a 65-mile, 660 MW undersea transmission power cable connecting Long Island to New Jersey, and 2) Hudson Transmission Partners, an 8-mile, 660 MW undersea transmission power cable connecting New Jersey to New York City.[13] Both lines were completed under budget and ahead of schedule.[14]

Starwood Energy also owns minority interest in certain transmission lines in California, Arizona, and Nevada, and developed wind generation in Texas,

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[10] Exhibit DCRT-1, Chapter I, *Prepared Direct Testimony of DCR Transmission, L.L.C. in Support of Its Application for a Certificate of Public Convenience and Necessity for the Ten West Link Project, Prepared Direct Testimony of Ali Amirali in Support of DCRT* (Amirali Opening Testimony), at I-3. Atlantica acquired the interest of Abengoa Transmission & Infrastructure, LLC during the course of the proceeding.

[11] *Ibid*.

[12] Application, at 17.

[13] *Id.,* at 18.

[14] *Ibid*.

gas generation in California, and solar generation in Ontario, Canada.[15] Starwood Energy's total investments include 65 MW biomass, 940 MW of wind generation, and 1.8 gigawatt (GW) of gas generation, including current ownership of two 50 MW gas projects in California, as well as investments in energy storage platforms.[16]

In 2019, 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 TPP studies, due to significant changes in both state policy and electricity market conditions since the CAISO Board approval.[17] The CAISO assessed both the production cost and capacity benefits associated with the Proposed Project[18] with reliability and public policy benefits in meeting overall resource adequacy (RA) and energy needs, including additional transmission capacity to the southwest and improving interregional opportunities for diversity benefits of sharing resources.[19]

All parties anticipate economic, reliability, and policy benefits to California ratepayers from the Proposed Project, although at differing levels.[20] The CAISO's updated analysis currently projects the BCR to range from 1.05 to 1.66, depending on the sensitivities and accounting for the uncertainties, discussed in

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[15] *Ibid.*

[16] *Ibid*.

[17] Exh. CAISO-03, *Opening Testimony of Neil Millar on Behalf of California Independent Systems Operator* (Millar Opening Testimony), *at* 12.

[18] *Ibid.*

[19] *Id.,* at 17.

[20] Application, at 2, *citing to* Memorandum from Keith Casey, Vice President, *Market & Infrastructure Development to ISO Board of Governors* (July 8, 2014).

detail in Sections 5.1.1 through 5.1.4. DCRT anticipates the BCR to range from 1.78 to 2.66, depending on one of the three production cost model (PCM) scenarios, discussed in detail in Section 5.2.1, below.[21] Cal Advocates anticipates a lower BCR range between 0.55 and 0.73, based on differing assumptions.[22]

1.2. Procedural Background

On October 12, 2016, DCRT filed an application for a certificate of public convenience and necessity (CPCN) to build the Proposed Project pursuant to the Rule 3.1 of Commission Rules of Practice and Procedure (Rules), and General Order (GO) 131-D (Application). Concurrent with the Application, DCRT moved to file the redacted portions of Appendixes D, J and N under seal pursuant to GO 66-D, Public Utilities (Pub. Util.) Code § 583, and Rules 11.1 and 11.4.

The Center for Biological Diversity, Yuma Audubon Society, Maricopa Audubon Society (collectively referred to as Conservation Groups) jointly filed a protest on November 21, 2016. Office of Ratepayer Advocates, now Public Advocates Office (Cal Advocates) filed its protest on November 28, 2021.

A prehearing conference (PHC) was initially set for April 27, 2017. This PHC was reset to May 15, 2017, and, later, to June 2, 2017. In advance of the initial PHC, the Applicant, Cal Advocates, and Conservation Groups each filed PHC statements. On June 2, 2017, the initial PHC in this proceeding was held.

On June 20, 2017, Conservation Groups and Colorado River Indian Tribes (CRIT) moved for party status, which was granted by ruling of the assigned Administrative Law Judge (ALJ) on July 27, 2017.

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[21] *Opening Brief of DCR Transmission, LLC*, filed February 12, 2021, (DCRT Opening Brief) at 1, *citing to* ACC 2020 Decision.

[22] Exh. CA PA-3, *Chapter 2: Ten West Link Benefit Analysis (Witness - Pushkar Wagle, Ph.D.)* (Wagle Opening Testimony), at 2-53. *See also*, Wagle Opening Testimony at 2-52 and Cal Advocates Reply Brief, at 6.

On June 30, 2017, Conservation Groups and The Utility Reform Network (TURN) filed Notices of Intent to Claim Intervenor Compensation. TURN did not actively participate in this proceeding, thereafter.

The assigned Commissioner and ALJ issued a Scoping Memo and Ruling (First Scoping Memo) on August 4, 2017. The First Scoping Memo identified, amongst other things, the issues within the scope of the proceeding and set the procedural schedule. The assigned Commissioner also determined that evidentiary hearings would be more effective and efficient after the environmental review was completed.

A second PHC was held on November 4, 2019, primarily to revisit the procedural schedule in view of the issuance of the Record of Decision (ROD) to the Final Environmental Impact Statement (FEIS).

On December 16, 2019, DCRT and the CAISO served its Opening Testimony.

On December 17, 2019, the assigned Commissioner issued an Amended Scoping Memorandum and Ruling (Amended Scoping Memo) to add an additional issue to the scope of the proceeding, after the CAISO updated its economic evaluation for the Proposed Project, and to update the procedural schedule for the proceeding.

On March 31, 2020, Arizona Corporation Commission (ACC), the Arizona regulatory body that ensures safe, reliable, and affordable utility services and railroad and pipeline systems, granted a Certificate of Environmental

Compatibility and authorized construction of the Arizona portion of the Proposed Project.[23]

On April 20, 2020, the assigned Commissioner issued the Second Amended Scoping Memorandum and Ruling (Second Amended Scoping Memo) to extend the procedural schedule for six weeks to allow completion of the modeling and review of the data derived from the modeling runs, as requested by Cal Advocates.

On May 13, 2020, Cal Advocates, Conservation Group, and CRIT served their Opening Testimony. On June 18, 2020, all parties served the Reply Testimony.

On July 23, 2020, the assigned ALJ held a status conference to notify the parties of the continuance of evidentiary hearings, due to the Commission's limited ability to conduct remote hearings and the Shelter-in-Place Order issued by the Governor of the State of California.

On October 27, 2020, the proceeding was reassigned to ALJ Daphne Lee. On November 20, 2020, the assigned ALJ issued a ruling setting a third PHC to be held on December 8, 2020, and ordering the parties to meet, confer, and submit a Joint PHC Statement prior to that PHC. The parties timely filed a Joint PHC Statement.

On December 2, 2020, the CRIT moved to withdraw their party status after reaching a settlement with Applicant, DCRT, outside of this proceeding.

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[23] *The Decision of the Arizona Corporation Commission in the Matter of the Application of DCR Transmission, L.L.C. or its Assignees, in Conformance with the Requirements of A.R.S. § 40-360 et seq., for a Certificate of Environmental Compatibility Authorizing the 500 KV Transmission Line, Which Includes the Construction of a New 125 Mile 500 kV Transmission Line Between Arizona Public Service Company's Delaney Substation Until Southern California Edison's Colorado River Substation, to be Referred to as the Ten West Link Project,* filed March 31, 2020 (ACC 2020 Decision).

On December 8, 2020, during the third PHC, the ALJ granted CRIT's motion to withdraw, and DCRT, CAISO and Cal Advocates advised that they were engaged in a negotiation to develop a set of stipulated facts and exhibits and anticipated conclusion of said negotiation around December 15, 2020. They advised that they expected to complete their negotiation and thereafter file a stipulation of facts and exhibits to expedite the resolution of the proceeding. The assigned ALJ ordered the parties to provide all parties on the service list a status update on the negotiation soon thereafter.

On December 17, 2020, DCRT advised the ALJ and the service list that additional time was needed to complete negotiation of stipulated facts. DCRT and Conservation Group anticipated completion by January 8, 2021.

On January 6, 2021, all parties jointly served and filed on the service list, the Parties' Stipulation of Facts and Admission of Exhibits.

On January 11, 2021, the parties moved Prepared Testimony and Exhibits into evidence. DCRT further moved to file under seal the stipulated Exhibits DCRT-2, DCRT-3, DCRT-5, DCRT-9, DCRT-11, DCRT-12, DCRT-16, and DCRT-18.

On January 21, 2021, this proceeding was reassigned to President Marybel Batjer as the assigned Commissioner. Upon the parties' request, the assigned ALJ set an interim proceeding schedule on January 25, 2021 (January 25, 2021 Ruling).

On January 29, 2021, Cal Advocates moved for oral argument pursuant to Rule 13.13. On February 2, 2021, this proceeding was reassigned to Commissioner Genevieve Shiroma.

On February 12, 2021, the parties timely filed their opening briefs. DCRT and Cal Advocates moved for oral argument within their respective opening

briefs.[24] On the same day, the ALJ granted the parties' Joint Motion for Leave to Admit Exhibits into Evidence, filed on January 11, 2021 (January 11, 2021 Joint Motion) and marked, identified, and received stipulated testimony and exhibits uploaded to the Commission's e-file system, consistent with the parties' January 11, 2021 Joint Motion.

On February 16, 2021, Commissioner Shiroma issued the Third Amended Scoping Memorandum and Ruling (Third Amended Scoping Memo), clarifying the scoped issues, confirming the proceeding schedule set forth in the January 25, 2021 Ruling, and extending the statutory deadline to November 30, 2021. Concurrently, in response to a motion by Cal Advocates, the assigned ALJ marked, identified, and received additional stipulated testimony and exhibits, which were mistakenly excluded in the January 11, 2021 Joint Motion.

On March 12, 2021, the parties filed their reply briefs, and the record was closed.

On March 24, 2021, the ALJ reopened the record to receive additional evidence necessary to rule on DCRT's October 12, 2016 and January 11, 2021 motions to file documents under seal. DCRT filed its compliance filing on April 5, 2021. After the ALJ issued further ruling directing DCRT to provide additional evidence, DCRT filed its Compliance Filing in Response to the ALJ Ruling on June 4, 2021.

On May 25, 2021, the ALJ granted Conservation Groups' motion, filed May 7, 2021, to withdraw their party status and opening and reply briefs.

[24] DCRT Opening Brief, at 53.

On July 1, 2021, Cal Advocates moved to admit two additional exhibits into evidence, 1) Exhibit (Exh.) Cal PA-26, the CAISO Active Generational Interconnection Queue as of June 22, 2021 (Interconnection Queue); and 2) Exh. Cal PA-27, the CAISO Preliminary Cluster 14 Project List as of May 20, 2021 (Project List). This motion was unopposed. The ALJ granted Cal Advocates' motion, directed Cal Advocates to upload the additional evidence to the Commission e-file system and allowed parties to brief the additional evidence.

On July 20, 2021, Cal Advocates filed the additional exhibits.

On July 23, 2021, DCRT, CAISO and Cal Advocates filed additional briefs.

On July 28, 2021, the ALJ issued a ruling granting, in part, the motions of DCRT to file the documents under seal for Appendix J and Portions of Appendix N of the Application and Exhs. DCRT-2, DCRT-3, DCRT-9, DCRT-11, DCRT-12, DCRT-16, and DCRT-18 of the evidentiary record and denying the motions for Appendix D, a portion of Appendix N and DCRT-5. This ruling also directed DCRT to file unredacted Appendix D, a portion of Appendix N and DCRT-5. On August 20, 2021, DCRT, in response to the ALJ ruling, filed the unredacted Appendix D, a portion of Appendix N and DCRT-5.

On August 24, 2021, the ALJ resolved outstanding evidentiary issues by identifying, marking and admitting CAL PA-26 and CAL PA-27 and determined that no further information or evidence was needed to adequately inform and evaluate the issues in this proceeding. Consequently, the ALJ closed the record, and the matter was submitted.

2. Issues Before the Commission

Pursuant to the assigned Commissioner's Third Amended Scoping Memo, the issues to be determined are:

1. Whether the Application meets the requirements of GO 131-D, Section IX(A)(1) and Rule 3.1 to obtain a CPCN;
2. Whether the Proposed Project serves a present or future convenience and need and meets the requirements of Pub. Util. Code §1001 *et seq.*;
3. What are the economic and other benefits of the Proposed Project?
4. Is there substantial evidence that the Proposed Project will have any significant impact on the environment? If there is substantial evidence of significant impact(s):
    a. What are the significant environmental impacts of the Proposed Project within the Commission's jurisdiction?
    b. Are there mitigation measures that will eliminate or lessen such impacts?
    c. Are the mitigation measures and/or alternatives infeasible for economic, social, legal, technological, or other considerations, including community values?
    d. What is the environmentally superior project alternative?
    e. To the extent that the Proposed Project or project alternatives result in significant and unavoidable impacts, are there overriding considerations that warrant Commission approval?
5. Whether the Proposed Project is necessary for compliance or to facilitate compliance with the Renewables Portfolio Standard (RPS)?
6. What is the maximum prudent and reasonable cost for the Proposed Project and environmentally superior alternative, if approved?
7. Whether the Commission should grant DCRT exemptions from certain affiliate transaction rules and reporting requirements?

8. Whether the FEIS complies with California Environmental Quality Act (CEQA); did the Commission review and consider it; and does it reflect the Commission's independent judgment and analysis?
9. Whether DCRT should provide a guarantee of payments for intervenors' consultants and the costs of intervenor compensation?
10. Whether the application raises any safety concerns or considerations?
11. Is the Proposed Project and/or environmentally superior project alternative designed in compliance with the Commission's policies governing the mitigation of electromagnetic field (EMF) effects using low-cost and no-cost measures?

3. General Order 131-D, Section IX(A)(1) And Rule 3.1.

Applications for the construction of a 500 kV transmission line must meet the filing requirements of Rule 3.1 as well as GO 131-D.

Here, the record reflects that the Applicant filed, as part of the Application, the filings as required under Rule 3.1 and GO 131-D. The Application and subsequent filings comply with the requirements under Rule 3.1 and GO 131-D as summarized below:

CRITERIA	DCRT SUBMISSION
GO 131-D(IX)(1)(a) and Rule 3.1(a)	Appendix A of the Application provides a detailed description of the proposed transmission facilities and equipment for the Proposed Project, and Appendix B to the Application provides a preliminary schedule.
GO 131-D(IX)(1)(b) and Rule 3.1(c)	Appendix C of the Application provides a scaled map of the original Submitted Route, showing parks, recreation areas and scenic areas, and existing transmission lines existing within a mile of the proposed route. Exh. DCRT-65 provides an updated map showing the Proposed Route as adopted from the Preferred Alternative of the FEIS.[25]
GO 131-D(IX)(1)(c) and Rule 3.1(e)	Proposed Project was selected by the CAISO as a primarily economically-efficient project that also provides significant reliability and policy benefit, thereby supporting a finding that public convenience and necessity require the construction and operation of the proposed transmission facilities.[26]
GO 131-D(IX)(1)(d) and Rule 3.1(f)	Appendix D and page 45 of Appendix N of the Application and Exh. DCRT-5 provide the Project Cost Estimate.
GO 131-D(IX)(1)(e)	DCRT initially selected the route described in the Application because it utilized the BLM designated utility corridors and largely followed the existing DPV transmission line to minimize the Proposed Project's environmental and visual impacts. Appendix E of the Application showed alternatives that were under consideration at the time the Application was submitted with a table summarizing the advantages and disadvantages of each alternative. DCRT's current Proposed Route for the Proposed Project is the BLM's Preferred Alternative as identified in the FEIS and BLM's ROD.
GO 131-D(IX)(1)(f)	Appendix B of the Application provides the preliminary construction schedule and the ROW acquisition activities. Exh. DCRT-4 and the Testimony of Lowell Rogers provide updated ROW acquisition activities.

GO 131-D(IX)(1)(g)	Appendix L of the Application provides the list of governmental agencies consulted and the results of those consultations.
GO 131-D(IX)(1)(h)	FEIS with collaboration with the Commission was issued on September 12, 2019.
Rule 3.1(b)	The Proposed Project will be operated as part of the CAISO-controlled transmission system and will not compete with any other utilities, corporations, person, or entities. While a portion of the Proposed Project will be located geographically within SCE's service area, neither SCE nor any other utility, corporation, or person will compete with the Proposed Project. The Proposed Project will not provide service within specific city or county, except as part of the CAISO-controlled transmission system.
Rule 3.1(d)	Appendix H of the Application identifies the permits the Proposed Project may require from federal, state, and local agencies for construction and operation of the Proposed Project.
Rule 3.1 (g)	DCRT relies on the financial resources of its controlling member, Starwood Energy, which manages total equity commitments in excess of $2 billion. Starwood Energy has executed transactions totaling more than $4 billion in enterprise value. Exhs. DCRT-1, DCRT-2 (Financial Ability and Financing Structure), and DCRT-3 (Financial Statement) detail financial information, ability, and structure of DCRT.
Rule 3.1(h)	DCRT did not prepare a rate schedule because cost recovery plus a reasonable rate of return will occur through the CAISO Transmission Access Charge (TAC), subject to Federal Energy Regulatory Commission (FERC) review and approval.

Rule 3.1(i) required DCRT to submit a statement corresponding to the statement required by Section 2 of GO 104-A. As discussed in detail under

[25] Exh. DCRT-65 at 22.

[26] Application, at 2.

Sections 8.2 and 8.3 of this decision, the Commission allowed DCRT to file the FERC Forms 1 and 3-Q as proxies in compliance with GO 104-A and Rule 3.1(i). Since the Proposed Project is not currently in operation, DCRT has not filed a FERC Form 1 or Form 3-Q. Hence, the Commission will excuse the requirement under Rule 3.1(i).[27]

4. General Background on the Commission's Integrated Resource Planning (IRP) Process and the CAISO's Transmission Planning Process

To determine whether the Proposed Project is necessary, we must first understand the assumptions used in the parties' PCM scenarios. For the Proposed Project, the crux of the parties' dispute are the portfolios from the 2017 integrated resource planning (IRP) process and the 2019 IRP process and the sources of the assumptions used in the PCM scenarios.

In 2015, the California Legislature, through Senate Bill (SB) 350, set the goal to reduce greenhouse gas (GHG) emissions by 40% of 1990 levels by 2030 and directed the Commission to develop an IRP process to ensure that California's electric sector meets its GHG reduction goals, while maintaining reliability at the lowest possible costs. In 2018, the California Legislature passed SB 100, which required 60 percent of electric retail sales be served by renewable resources by the year 2030 and zero-carbon resources to supply 100 percent of electric retail sales to end-use customers by 2045.

The Commission's ongoing IRP process provides guidance to Load Serving Entities (LSEs), developers of generating resources and other entities on the optimal path for the state to achieve these state goals, at the least cost to California retail ratepayers, while maintaining reliability. The IRP process

[27] FERC Form 1 and Form 3-Q are required forms for reporting to FERC once the Proposed Project is constructed and operational.

provides the analytical foundation for Commission orders for LSEs to procure renewable and other diverse electricity resources. The IRP process also produces portfolios of future generation which the CAISO analyzes within its annual TPP to determine the implications for the transmission system.

To achieve the goals of SB 350 and SB 100, the Commission, the CAISO, and the California Energy Commission (CEC) established coordinated processes to ensure that there is a common understanding of expectations regarding the development of renewable generation portfolios feeding into the annual TPP cycle. This includes using the assumptions in the load forecast which is included and regularly updated within the CEC's Integrated Energy Policy Report (IEPR).

The recurring modeling analysis conducted throughout each IRP cycle produces a Reference System Plan (RSP) and a Preferred System Plan (PSP) that reflect the optimal set of future resource needs to meet the GHG target for the electricity sector. These plans also provide the foundation for the portfolios that the Commission transmits to the CAISO's annual TPP.

The IRP process is designed to be regularly updated to reflect changes in GHG reduction target, reliability requirements, expected resource costs, expected levels of imported electricity and other key constraints that are incorporated into the modeling.

During the 15-month TPP cycle, the CAISO identifies and assesses the transmission implications from the types and amounts of renewable generation that will be needed to meet state policy goals and future needs of the CAISO-controlled transmission grid.[28] Each TPP also assesses the economic costs and benefits of nominated transmission projects. For each TPP cycle, the

[28] Millar Opening Testimony, at 2.

CAISO's analysis assumes that transmission projects that have been approved in previous TPPs will be developed, thus signaling to generation developers the areas where potential transmission access will be available.

The Commission adopted the PSP for the 2017-2018 IRP process on May 1, 2019.[29] On April 6, 2020, the Commission adopted 2019-2020 RSP to be used by all LSEs required to file individual integrated resource plans in 2020.[30] On February 11, 2021, in Decision (D.) 21-02-008, the Commission approved a set of portfolios for analysis in the 2021-2022 TPP. This aligns with the 2019-2020 RSP and the direction given to the LSEs for planning in D.20-03-028. On August 17, 2021, the Commission, in the IRP proceeding, sought comment on the proposed 2019-2020 PSP.[31]

5. Project Need

The Commission is charged with ensuring that public utilities furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public.[32] Pursuant to Pub. Util. Code § 1001, a utility intending to construct or extend transmission line facilities, designed for immediate or eventual operation at 200 kV or more, must first obtain a CPCN from the Commission.[33] The CPCN is issued upon

[29] D.19-04-040.

[30] D.20-03-028.

[31] ALJ's Ruling Seeking Comments on Proposed Preferred System Plan filed August 17, 2021, in R.20-05-003.

[32] *Utility Consumers' Action Network v. Public Utilities Com.* (2010) 187 Cal.App.4th 688, 689 *citing to* Pub. Util. Code § 451.

[33] Pub. Util. Code, § 1001. *See also* General Order (GO) 131-D at 1.

Commission finding that "the present or future public convenience and necessity require or will require such construction."[34]

At issue in this proceeding is a determination by the CAISO on the cost-effectiveness and need for the Proposed Project, a transmission project. In Decision (D.) 06-11-018, the Commission examined "what deference should be given to determinations by the CAISO regarding the cost-effectiveness and need for a transmission project that is proposed for its economic benefits."[35]

D.06-11-018 sets forth general principles, minimum requirements, and other guidance for economic evaluations of proposed transmission projects subject to CPCN proceedings. Specifically, D.06-11-018 established a rebuttable presumption in favor of a CAISO Board-approved economic evaluation, provided: (1) the CAISO Board has made certain explicit findings regarding the economic value of the Proposed Project; (2) the CAISO Board-approved evaluation is consistent with the principles and minimum requirements set forth in D.06-11-018; and (3) the CAISO Board-approved evaluation is submitted to the Commission within sufficient time to be included within the scope of the proceeding.[36]

To overcome this presumption, the party opposing the Proposed Project bears the burden of demonstrating either (1) that the CAISO Board-approved economic evaluation does not comply with the principles and minimum requirements of D.06-11-018 or (2) that the project is not cost-effective.[37]

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[34] Pub. Util. Code, § 1001.

[35] D.06-11-018, at 2.

[36] *Id.*, at 3.

[37] *Ibid*.

The principles and minimum requirements for the CAISO's economic evaluations shall evaluate the following:

1. The CAISO's standardized benefit-cost methodology, used to measure the economic benefits of proposed transmission projects;[38]
2. The CAISO's framework for the computation of potential energy benefits;[39]
3. Other economic effects of a transmission project, including economic effects that may not be quantifiable;
4. Uncertainty about future system and market conditions, affecting the likelihood that a transmission project's forecasted benefits will be realized;
5. Baseline resource plans and assumptions about the system outside the applicant's service territory that are consistent with resource plans and system assumptions used in procurement or other recent Commission proceedings, updated as appropriate; and
6. Feasible resource alternatives to the proposed transmission project.[40]

5.1. The CAISO's Economic Evaluation of the Proposed Project

Separate from the coordinated interaction with the Commission during the TPP cycle, the CAISO assesses economic benefits of proposed transmission projects by simulating production costs.[41] When determining whether a

[38] The perspective of CAISO ratepayers is of primary importance in a CPCN proceeding, although there is value in reviewing benefit-cost results from other perspectives as well. *See*. D.06-11-018, at 4.

[39] Parties shall assess energy benefits using established, credible, and commercially available production cost modeling tools. The applicant may decide whether to include market power mitigation benefits as part of its demonstration of need for a proposed transmission project. *Ibid.*

[40] *Ibid*.

[41] Spending over 8,760 hours in a study year, the CAISO considers unit commitment, generator dispatch, locational marginal prices, and transmission line flows.

particular solution is needed, the CAISO must consider comparative costs and benefits[42] of viable alternatives to the particular transmission solution including: 1) other potential transmission solutions, including those being considered or proposed during the TPP; 2) acceleration or expansion of any transmission solution already approved by the CAISO Governing Board or included in any TPP, and 3) non-transmission solutions, including demand-side management.[43]

The CAISO originally determined the Proposed Project's economic benefits based on (1) capacity benefits from the increased amount of out-of-state resources in the Southwest to count for RA and (2) production cost benefits from the Proposed Project's ability to reduce the CAISO net ratepayer payments.[44] The Proposed Project's economic benefit is intertwined with reliability benefits to achieve state policy needs. When evaluating the Proposed Project, the CAISO concluded that the quantified economic and reliability benefits exceeded

[42] The CAISO assesses the benefits of a proposed transmission project using five categories, production, capacity, public-policy, renewable integration and avoided cost of other projects. Production benefits are benefits to ratepayers resulting from changes in the net ratepayer payment based on production cost simulation from the proposed transmission project. Capacity benefits are benefits to ratepayers resulting from increased importing capability into the CAISO's Balancing Authority Area (BAA) or into a local capacity requirement (LCR) area. Capacity benefits analysis also includes benefits resulting from decreased transmission losses and increased generator deliverability. Public-policy benefit is the benefit to ratepayers through reduction of the cost of reaching renewable energy targets by facilitating the integration of lower cost renewable resources located in remote areas, or by avoiding overbuild. Renewable integration benefit is the interregional transmission upgrades, allowing sharing energy and ancillary services among multiple BAAs, which help mitigate integration challenges, such as over-supply and curtailment. Avoided cost of other projects is the avoidance of a reliability or policy project because of the economic project under study. The avoided cost contributes to the benefit of the economic project. *See* Exhibit Ca PA-2, *Public Advocates Office Opening Testimony of Jerry Melcher, Transmission Planning Process, and the Application of the Transmission Economic Assessment Methodology* (Melcher Opening Testimony), at 2.

[43] Exhibit CAISO-6, Millar Rebuttal Testimony, at 2, *citing to* CAISO tariff, Section 24.4.6.7 Economic Studies and Mitigation Solutions.

[44] Yimer Corrected Rebuttal Testimony, at 4-5.

estimated costs.[45] The CAISO also found the following additional potential benefits:

1. Mitigation of the impacts of higher contingency flows on neighboring systems;[46]
2. Opportunities for CAISO-connected renewable generation to develop in the Delaney area;
3. Increase in deliverability from the Imperial Valley zone; and
4. Increase competition in the California generation market.[47]

The production cost benefit for the Proposed Project includes these three benefits to CAISO ratepayer: 1) consumer energy cost decreases; 2) increased LSE-owned generation revenues; and 3) increased transmission congestion revenues. Based on these findings, the CAISO Board approved the Proposed Project in its 2013-2014 TPP.

In 2019, the CAISO found a continuing necessity for the Proposed Project after updating its economic evaluation, based on study assumptions, base cases, and the Commission-developed renewable generation portfolios prepared for the 2019-2020 TPP studies.[48]

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[45] *Id*. at 9.

[46] Los Angeles Department of Water and Power's Marketplace, Adelanto 500 kV line in particular, caused higher contingency flows on neighboring systems as a result of the development of renewable generation in southeastern California and the retirement of gas generation in southwestern California

[47] *Ibid*.

[48] Millar Opening Testimony, at 4 and 12.

5.1.1. The CAISO's Framework for the Computation of Potential Energy Benefits

Based on the CAISO's Transmission Economic Analysis Methodology (TEAM), the CAISO ran two different PCM scenarios: 1) Baseline Scenario and 2) Sensitivity Scenario with updated natural gas and carbon prices in 2014.[49] The baseline scenario shows a total of $33.6 million in production cost benefits annually.[50] The sensitivity analysis, using higher natural gas prices in California compared to decreased natural gas prices in other states, increased production cost benefits to $46.6 million annually.[51]

Taking the production cost benefit and capacity benefits from the avoided capacity costs for battery storage and the locational renewable capacity cost savings, the CAISO calculated the BCR to range from 1.16 to 1.54.[52]

The CAISO approached the updated economic assessment in three steps: 1) resource portfolios are developed based on Commission's RESOLVE;[53] 2) the resource portfolios are then used to conduct production cost simulation and production benefit analysis, while the 2019-2020 Transmission Plan economic planning PCM with the Updated Resource Portfolio is used to conduct the production cost simulation;[54] and 3) using the results of the first two steps, the

[49] Yimer Opening Testimony, at 3-4.

[50] Yimer Corrected Rebuttal Testimony at 6. *See also*, Exh. CAISO-2, *Opening Testimony of Neibyu Yimer on Behalf of the California Independent Systems Operator* (Yimer Opening Testimony), at 16.

[51] Zhang Opening Testimony, at 4-7.

[52] *Id.*, at 8-10.

[53] Yimer Opening Testimony, *supra*, at 3. The RESOLVE model is the final model developed in the Commission's 2017-2018 IRP process, which was used to inform the CAISO's 2019-2020 TPP.

[54] The key assumptions of the 2019-2020 economic planning PCM are described in Appendix I to the Zhang Opening Testimony.

BCR for the Proposed Project was calculated based on the estimated 2021 in-service date of the Proposed Project.[55]

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

1. Continued growth of the grid-connected solar in excess of the level anticipated in the 2013 timeframe;
2. Rapid deployment of distributed energy resources far exceeding industry expectations, e.g., rooftop solar PV;
3. Decreasing battery storage costs;
4. Actual and forecast reductions in the out-of-state thermal fleet, including out-of-state coal resources;
5. LSE requirements under SB 100 to acquire 60% of their energy from renewable resources by 2030 and 100% of energy from non-GHG-emitting generation by 2045;
6. 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; and
7. Advancement of generation and transmission planning and development processes.[56]

5.1.2. The CAISO's Analysis of Arizona Solar and Battery Capacity Savings

Part of the CAISO's determination of the Proposed Project's capacity benefits is based upon the solar generation from Arizona using assumptions

[55] Zhang Opening Testimony, at 3.

[56] Over the last five years, there were 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. Millar Opening Testimony, at 15-16.

derived from the 2017-2018 PSP.[57] The public-policy benefits of the Proposed Project arose from the increase of the amount of lower cost, out-of-state resources in the Southwest, including the CAISO grid-connected solar and solar-storage hybrid resources in western Arizona (Arizona Solar), that counts towards meeting RA goals.[58]

Using the latest version of RESOLVE, the CAISO determined the amount of solar from Arizona inside the CAISO Balancing Authority Area (BAA), that can be economically selected to achieve emissions and RA targets and removed the transmission cost adder for delivery to the California boarder associated with the Arizona Solar resource.[59] After enabling Arizona Solar as a candidate resource in RESOLVE, the CAISO calculated that 3262 MW of Arizona Solar from the Proposed Project can be economically selected to meet the RA target.[60]

By modeling the resource shift from enabling Arizona Solar as a candidate resource in RESOLVE and using the deliverability power flow model developed for its 2019-2020 TPP to perform a deliverability assessment, the CAISO estimated the incremental amount of economically-selected Arizona Solar capacity that can count for RA.[61] Because the objective of the deliverability

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[57] CAISO compared the data from the 2017 IRP portfolio and 2019 IRP portfolio with the data from the 2018 National Renewable Energy Labs (NREL) Annual Technology Baseline (ATB) and the 2020 Energy Information Administration (EIA) reports and concluded that the 2019 IRP reported capital cost and levelized costs of energy for PV between California and Arizona did not align with findings from the NREL ATB or the EIA report. As such, the 2017 IRP portfolio assumption more closely aligned with those reports. Yimer Corrected Rebuttal Testimony, at 7-11.

[58] *Ibid*., at 10-11.

[59] The Commission made the same corrections to the RESOLVE model used in the 2019-2020 IRP. *See,* Yimer Corrected Rebuttal Testimony, at 3.

[60] Yimer Opening Testimony, at 15-16.

[61] *Id*., at 11.

assessment is to determine the amount of Arizona Solar capacity that can count for RA, all of the Arizona Solar resources were modeled as seeking full capacity deliverability status (FCDS).[62]

In the deliverability power flow case with the Proposed Project, Arizona Solar was distributed among Delaney (60%), Hassayampa (20%) and Hoodoo Wash (20%) substations approximately in the same proportion as resources in the CAISO Generation Interconnection Queue.

The CAISO compared the generation at the substations when the economically-selected Arizona Solar was allocated to Delaney, Hassayampa, and Hoodoo Wash substations against generation at only Hassayampa and Hoodoo Wash substations, with the Delaney substation's share of Arizona Solar allocated to Hassayampa and Hoodoo Wash substations.[63] The constraint limits the amount of economically-selected Arizona Solar that can count for RA to about 2,149 MW with the Proposed Project. Without the Proposed Project, same constraint limits Arizona Solar deliverability to 1,180 MW.[64]

Applying the effective load carrying capability (ELCC) methodology, adopted by the Commission, to determine the RA value for solar resources,[65] the Proposed Project provides an increase of 969 MW in deliverable Arizona Solar capacity, which is equivalent to a net qualifying capacity (NQC) of 136 MW,[66] to

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[62] *Ibid*.

[63] Delaney substation will be outside the CAISO BAA without the Proposed Project. *Ibid.*

[64] Without the Proposed Project, the most limiting contingency is an outage of the Ocotillo–Suncrest 500 kV line, which overloads the Eco-Miguel 500 kV line.

[65] Yimer Opening Testimony at 13. This means that for every MW of installed and deliverable solar capacity, the Commission applies a discount to determine the solar resource's actual contribution to meeting load requirements.

[66] The CAISO calculated the NQC based on the ELCC values for solar adopted in 2019. *Id.* at 13-14, *citing to* D.19-06-026.

count towards RA capacity that would otherwise need to be procured from other resources.[67] Based on the same assumptions, the equivalent of 969 MW in deliverable solar capacity, or 29.7 percent of the economically-selected Arizona Solar capacity, will have to come from renewables located in less economic locations subject to deliverability constraints, if the Proposed Project is not built. This resource shift will result in resource cost saving of $977 million in present value of revenue requirements or $58 million in terms of annual levelized cost, both in 2016 dollars.[68]

In evaluating the battery capacity savings, the CAISO interpolated cost projections for a lithium-ion battery energy storage system (BESS) for year 2022 and calculated the levelized cost of 136 MW of BESS $36.3 million per year for the capacity benefit based on the avoided cost of energy storage.[69] The CAISO calculated the capacity benefit to be $290.3 million in terms of present value or $17.3 million in terms of levelized annual benefits.[70]

5.1.3. The CAISO's Natural Gas Price Analysis

The CAISO used the 2018 IEPR natural gas price forecast for its baseline PCM scenario and the 2019 preliminary IEPR natural gas price forecast for its a sensitivity PCM scenario. The CAISO's baseline PCM monthly natural gas price differential between Arizona South and Southern California is between $0.581 to 0.597, similar to the lower end of the price differential referenced by Cal

[67] *Id.*, at 11-13.

[68] For the purposes of modeling in RESOLVE, resources located in Southern Nevada are assumed to interconnect directly to the existing CAISO transmission system. This assumption has been updated from the Commission's solar resources in southern California and southern Nevada in the same year and wind resources in the Southwest in 2030. Yimer Opening Testimony, at 6-9.

[69] *Id.,* at 14.

[70] *Id.,* at 14-15.

Advocates.[71] The sensitivity PCM scenario applied a relatively large natural gas price differential between Arizona and Southern California, consistent with the 2019 IEPR natural gas forecast, to represent the upper bound for natural gas price differentials between Southern California and Arizona. Together, the CAISO's baseline and sensitivity PCM scenarios covered a wide and reasonable range of natural gas price differentials between Arizona and Southern California.

5.1.4. The CAISO's Consideration of Uncertainties

The CAISO considered multiple uncertainties in its economic evaluation. Recognizing that the capacity value of solar resources will likely continue to decline in the future as more solar resources are added and post-sunset energy needs become more predominant, the CAISO calculated reduction of capacity for Arizona Solar and natural gas benefits based on one-third, one-half, and two-thirds of the capacity benefit values to account for this uncertainty.[72]

The CAISO also considered the uncertainty in the costs of utility-scale battery cost and found the estimated cost of a 4-hour lithium-ion utility-scale battery system cost varies significantly from about a low of $1,100/kW to a high of $2,250/kW in 2018 dollars, based on the review of a study by the Western Electric Coordinating Council (WECC).[73]

The CAISO used $1661/kW in its analysis to represent approximately the midpoint of the range.[74] Similarly, the CAISO considered the significant uncertainty regarding the future rate of decline in battery storage costs with one

[71] Arizona South Hub represents the Arizona Phoenix natural gas hub.

[72] Yimer Opening Testimony, at 15.

[73] WECC promotes Bulk Electric System (BES) reliability for the entire Western Interconnection system from Canada to Mexico and includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 Western states.

[74] Yimer Corrected Rebuttal Testimony, at 19.

report finding that year-over-year cost declines were less pronounced, particularly for wholesale systems.[75]

Due to the uncertainties associated with the actual cost of battery storage, the CAISO assessed the Proposed Project's BCR with the battery storage costs based upon the 2019 IRP portfolios as an additional data point by establishing a baseline calculation on the avoided cost of battery storage with the storage cost assumption from the 2019 IRP portfolios. The evaluation resulted in a BCR between 1.05 to 1.31, with capacity benefits discounted by two-thirds, one-half, and one-third to adjust for the solar resource uncertainty. When the 2019 IEPR Preliminary Forecast is included in the baseline model, the BCR increased and was between 1.38 to 1.66.[76]

5.1.5. Rebuttable Presumption Exists in Favor of CAISO Board-Approved Economic Evaluation

Here, we find that consistent with D.06-11-018: (1) the CAISO Board has made explicit findings regarding the economic value of the Proposed Project; (2) the CAISO Board-approved evaluation is consistent with the principles and minimum requirements set forth in D.06-11-018; and (3) the CAISO Board-approved evaluation has been submitted to the Commission within sufficient time for its inclusion within the scope of the proceeding.

First, the CAISO Board found explicit findings of quantifiable capacity and production cost benefits with reliability benefits from the Proposed Project in the baseline and sensitivity scenarios to conclude that the Proposed Project provides economic and public policy benefits. In the CAISO's updated economic

[75] *Id., at* 18-21.

[76] Exh. CAISO-4, Zhang Rebuttal Testimony, at 7-9. The CEC prepares the IEPR, which provides a cohesive approach to identifying and solving the state's pressing energy needs and issues.

evaluation, the CAISO further found benefits derived from Arizona Solar and potential battery capacity in expanding the CAISO BAA in this Proposed Project and calculated the production cost savings of $33.6 million.

Second, the CAISO Board-approved evaluation is consistent with the principles and minimum requirements set forth in D.06-11-018. The CAISO's economic evaluation for the Proposed Project applied CAISO's standardized benefit-cost methodology, TEAM, to measure the economic benefits of the Proposed Project. The framework of this economic evaluation computed the potential energy benefits and other economic effects of Proposed Project. Using the PSP derived from the Commission's 2017 IRP process, the CAISO applied this baseline resource plans and assumptions about the system outside the DCRT's service territory that are consistent with resource plans and system assumptions used in procurement and the TPP cycles for 2019-2020 and the 2020-2021.[77] Moreover, the CAISO considered the uncertainties of future systems in solar generation, in natural gas pricing and the utility-size battery costs, along with market conditions affecting the likelihood that a transmission project's forecasted benefits to be realized. Finally, the CAISO considered alternative interconnection projects and the Palo Verde intertie when determining the economic benefits of the Proposed Project.

Third, the CAISO Board-approved evaluation presented to the Commission as part of the evidence for this proceeding.

Upon review of the foregoing, the Commission finds that the CAISO's original and updated economic evaluation comply with the principles and minimum requirements under D.06-11-018 and should be presumed reliable in

[77] *See* D.20-03-028 and D.21-02-008.

determining the necessity of the Proposed Project. Thus, a rebuttable presumption in favor of the CAISO Board-approved economic evaluation exists here.

5.2. DCRT's Economic Evaluation

In addition to the rebuttable presumption in favor of the CAISO Board-approved economic evaluation which supports the need for the Proposed Project, DCRT additionally argues that the Proposed Project is needed to reduce overall costs to the CAISO ratepayers and increase system reliability while providing some renewable source of energy to meet the State's policy goals.[78] DCRT concluded that the economic benefits includes: 1) reduced production costs and CAISO customer net payments; 2) reduced energy losses; 3) increased competition at the Palo Verde trading hub; 4) increased transmission transfer capability between CAISO and APS in the Western Energy Imbalance Market (EIM); and 5) reduced RA costs.[79]

DCRT estimates the Proposed Project will reduce ratepayer costs by $1-1.6 billion over a 50-year economic life with the present value of the revenue requirement of $607 million with an after-tax weighted average cost of capital of 6.8%; Federal income tax of 21%; California income tax 8.84%; a tax depreciated based on a 15 year Modified Accelerated Cost Recovery System (MACRS) schedule; and a straight-line book depreciation over 40 years.[80]

DCRT and the ACC concluded that the Proposed Project presented no negative impact to the reliability or safety to the Arizona transmission

[78] Millar Opening Testimony, at 2.

[79] Exh. DCRT-1, Chapter IV, Chang Opening Testimony, at IV-2-IV-3.

[80] *Id.*, at IV-37. The assumptions do not include economic, policy, and reliability benefits to CAISO customers.

infrastructure or to the delivery of power to Arizona ratepayers.[81] In granting authorization to construct the Proposed Project, ACC reviewed DCRT's economic evaluation and found that the Proposed Project would result in stronger transmission infrastructure while reducing congestion in Arizona.[82]

5.2.1. DCRT's Analysis of the Economic Benefit of the Proposed Project

If the CAISO did not complete an economic evaluation, D.06-11-018 required the applicant in a CPCN proceeding to use baseline resource plan and assumptions about the system outside its service territory that are consistent with its resource plan and system assumptions used in procurement or other recent Commission proceedings.[83] In its showing, the applicant should identify clearly and explain any changes to its baseline resource plan or to prior assumptions about transmission and generation resources in other parts of the study area.[84] The applicant should also specify the criteria it used to determine the inclusion, exclusion, and retirements of generation, transmission, and other resources, and also the sources and justification for its assumptions about the system outside its service area.[85]

Based on a combination of information from the Brattle Ten West Link Technical Report (Brattle Report)[86] and three different PCM scenarios, DCRT projected 1) annual savings between $7 million to $36 million; 2) reduction in curtailment of renewable generation by increasing operational flexibility of the

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[81] ACC Decision, at 4.

[82] Exh. Cal PA-24, Little Testimony, at 13-14.

[83] D.06-11-018, at 69.

[84] *Id.,* at 70.

[85] *Ibid*.

[86] *See* Exh. DCRT-13, *Appendix L- Brattle Ten West Link Technical Report*.

CAISO system; 3) more options to integrate and access to renewable energy resources to achieve the goals to reduce GHG;[87] and 4) increased reliability of the California and Arizona transmission network by increasing reliable power transfers in the region.[88]

DCRT's PCM scenarios did not analyze the impact on renewable generation interconnection but accounted for transmission congestion due to intertie scheduling limits on the CAISO's neighboring markets and additional congestion due to the Palo Verde intertie during peak and overnight hours.[89]

DCRT modeled three scenarios, Scenarios A, B and C, with varying assumptions. In Scenario A, DCRT applied the resource portfolios used in the 2018-2019 TPP and progressively added layers of assumptions in Scenarios B and C to model potential costs and savings associated with the Proposed Project. In Scenario B, DCRT added updated generation resource mix and calculated an increase in all base categories, with notable increases for battery capacity (143%), geothermal capacity (56%), solar (12%), wind (7%) and less than 1 percent of

[87] 4150 MW of solar and storage capacity projects are in the CAISO interconnection queue to connect the Proposed Project and 900 MW of solar and storage capacity projects are in the APS interconnection queue to connect to Delaney Substation. Chang Opening Testimony at IV-31. As of June 2021, the CAISO Interconnection Queue Report reflects 9400 MW of renewable resources seeking to interconnect to the Proposed Project. *Amended Brief of DCR Transmission L.L.C. Addressing Exhibits Cal PA-26 and Cal PA-27*, filed July 30, 2021 (DCRT Additional Brief), at 2.

[88] Chang Opening Testimony, at IV-3-IV-4.

[89] *Id.*, at IV-14.

other generation.[90] In Scenario C, DCRT added to Scenario B the natural gas price forecasts, summarized by the CEC as a 12.8% decrease by 2028.[91]

DCRT's assumptions were taken from the most up-to-date information available from the Commission, CEC and the CARB at the time of calculation. DCRT found savings for California ratepayers were $7 million per year under Scenario A, $19 million per year under Scenario B, and $36 million per year under Scenario C.

Based on the Brattle Report and the three PCM scenarios, DCRT concluded that the Proposed Project will provide an estimated range of savings of $62-93 million per year and broken down into 1) CAISO production cost savings of $41-70 million per year; 2) reduction in transmission energy losses of $3-4 million per year; 3) reduction in renewable curtailments of $0.3-0.9 million per year; and 4) increase in renewable procurement of $18 million per year.[92] DCRT calculated the BCR range from 1.78 to 2.66.[93]

5.2.2. DCRT's Analysis on the Public Policy Benefits

DCRT anticipates several public policy benefits from the construction and operation of the Proposed Project. The Proposed Project will 1) increase the transfer capability across the congested portion of the CAISO system between Palo Verde and Southern California, also known as the Palo Verde intertie, and,

[90] Arguments can be made that the increases in certain sectors are too large or small, but costs continue to decrease. No party has made claims that increases in certain sectors are not projected.

[91] Scenario A began with the 2018-2019 TPP, Scenario B then added 2028 generation resource mix information, and Scenario C then added 2028 projected gas prices based on the 2018 IEPR.

[92] Exh. DCRT-1, Chapter III, Mackin Opening Testimony, at III-4.

[93] Chang Opening Testimony, at IV-37.

thereby, reducing congestion and customer costs in California;[94] 2) unload energy across highly utilized transmission lines to reduce energy loss, while encouraging further development of RA to connect to the Palo Verde hub to increase competition and meet RA goals for California;[95] and 3) expand the BAA for CAISO and APS so that both can benefit from the EIM, in addition the estimated production cost benefits.[96]

DCRT calculated that the Proposed Project will 1) increase transfer capability by 690 MW between California and Arizona when all lines are operational; 2) allow an additional 781 MW generation to the Delaney Substation and output to southern California; and 3) transfer an additional 219 to 257 MW between Arizona and California under transmission outage conditions.[97]

DCRT expects the Proposed Project will provide additional public policy benefits, including the increase ability to achieve California's de-carbonization goals at a lower cost and reliability on the CAISO system in Southern California, while reducing renewable procurement costs and curtailment of renewable generation.[98]

Based on Scenarios A, B, and C, DCRT found that the reduction in renewable curtailment and cost savings from building solar resources in Arizona to be between $18.2 to $18.7 million in 2028 dollars.[99]

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[94] *Id.,* at IV-2.

[95] *Id.*, at IV-3.

[96] *Ibid*.

[97] Mackin Opening Testimony, at III-4.

[98] Chang Opening Testimony, at IV-3-IV-4.

[99] *Id.*, at IV-32.

5.3. Cal Advocates' Rebuttal to the Presumption in Favor of the CAISO-Board Approved Economic Evaluation

To overcome the presumption in favor of a CAISO Board-approved economic evaluation, Cal Advocates presented the following arguments: 1) the CAISO's updated economic evaluation did not meet the requirements of the rebuttable presumption because it was not approved by the CAISO Board; 2) the BCR from the CAISO and DCRT models are inflated and based on outdated assumptions; and 3) the Proposed Project is unnecessary to achieve California's RPS goals set forth in SB 350 and SB 100.[100] As discussed below, we are not persuaded by these arguments.

5.3.1. CAISO's Updated Economic Evaluation Do Not Need Further CAISO Board Approval

The Proposed Project had already received CAISO Board approval in 2014, citing to economic, reliability and public policy benefits.[101] The CAISO explains that the CAISO Board, since 2014, did not have any reason to revisit project need, since its updated economic analysis showed continuing net economic benefits to CAISO ratepayers. The CAISO tariff also did not require the CAISO Board to revisit a project once the Proposed Project was approved.[102]

As the CAISO Board approved the Proposed Project after evaluating economic benefits in 2014 and the updated economic evaluation found continuing economic benefits, the Commission finds that further CAISO Board approval of the updated economic evaluation for the Proposed Project is

[100] Wagle Opening Testimony, at 2-6.

[101] Millar Rebuttal Testimony, at 2.

[102] *Rebuttal Brief of the California Independent System Operator* filed March 12, 2021 (CAISO Rebuttal Brief), at 4.

unnecessary to meet the minimum requirements under D.06-11-018 in this proceeding.

5.3.2. CAISO's Application of the IRP Portfolios are Reasonable and Proper

Cal Advocates argues that the economic benefits are based on outdated assumptions and inflated benefits. Specifically, Cal Advocates believes that the CAISO erroneously applied 16% differential for the capital cost of solar between Arizona and California, based on the portfolios from the 2017 IRP process, rather than the 3.6% differential, based on the portfolios from the 2019 IRP process.[103] Cal Advocates further believes the CAISO allocated solar resources improperly and did not conduct sufficient range of uncertainty analysis.[104]

Cal Advocates also argues that the 2019 IEPR forecast for earlier years has a larger differential in natural gas prices between Arizona and Southern California Gas hubs than the forecast for later years. Cal Advocates compared the projected natural gas prices of Arizona Phoenix hub and Southern California hub. The projected natural gas price differential between Arizona Phoenix hub and Southern California in 2028 is $1.13/MMBtu, which would drop to $0.58/MMBtu in 2055.[105] Because of that, Cal Advocates claims that using the 2019 IEPR natural gas price forecast from earlier years overstated the value of the Proposed Project.

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[103] Wagle Opening Testimony, at 2-25 and Chang Opening Testimony, at IV-29.

[104] When Cal Advocates referred to the 2017 IRP and 2019 IRP, the Commission inferred that Cal Advocates intended to reference the portfolios from the 2017 IRP process and 2019 IRP process. Cal Advocates Opening Brief at 15-16. *See also, Reply Brief of Public Advocates Office*, filed March 12, 2021 (Cal Advocates Reply Brief), at 10.

[105] *Ibid*., at 2-29.

In addition, Cal Advocates asserts that anticipated growth in battery storage will lead to change in future need of transmission projects and criticizes the limitation of the CAISO's estimate for storage growth.

At the time the CAISO completed the updated economic evaluation, the 2017-2018 PSP and the 2019-2020 RSP were the most updated IRP portfolios adopted by the Commission. The CAISO reviewed other industry reports on the capital costs of solar generation in Arizona, which aligned more with the portfolios from the 2017 IRP process, rather than 2019 IRP process, as argued by Cal Advocates.[106]

As consistent with the 2019-2020 and the 2020-2021 TPP cycles, the CAISO properly applied the PSP adopted by the 2017 IRP cycle as the base case and the RSP adopted by the 2019 IRP cycle as the policy-driven sensitivity in the economic evaluation of the Proposed Project to align with the transmission planning coordinated between the Commission, CAISO and CEC.[107]

Moreover, Cal Advocates offers no new modeling outcomes and merely asserts flaws in the modeling and cost assumptions relied upon by the CAISO in its updated economic analysis of the Proposed Project. Cal Advocates substituted different cost assumptions from the Commission's *Inputs and Assumptions: 2019-2020 Integrated Resource Planning* (2019-2020 IRP assumptions), which was not available to the CAISO when the updated economic analysis for solar resources was completed. With the 2019-2020 IRP assumptions, Cal Advocates calculated a BCR between 0.55 to 0.73 and showed that the Proposed

[106] Yimer Corrected Rebuttal Testimony, at 8.

[107] D.20-03-028 at 4. *See also*, D.21-02-008.

Project will result in benefits to the California ratepayers, even if it is less than anticipated by CAISO and DCRT.[108]

It is also important to note that the IRP process continually updates information resulting in refreshed assumptions which would suggest different economic benefits for meeting the state's future resource needs. The holistic and ongoing IRP process, in coordination with the comprehensive TPP cycle, develops conclusions that are relied upon by developers and should be assumed to be consistent with the state's overall needs and direction.

Cal Advocates finally contend that the reliability benefits should be disregarded because the Proposed Project was not formulated to solve a reliability concern but provided no evidence to support its argument. We find this argument unpersuasive.

Upon review of the evidence and the Commission's IRP process, the Commission finds that the CAISO's use of the Commission-recommended portfolios from the IRP process is reasonable and appropriate.

5.3.3. CAISO Interconnection Queue and Project List Do Not Rebut the Presumption Afforded to CAISO's Economic Evaluation

Citing to the Interconnection Queue and the Project List, Cal Advocates believes the Proposed Project is unnecessary because the Interconnection Queue and the Project List reflect an approximately 68,000 MW of solar photovoltaic (PV) and approximately 131,000 MW of battery storage generation seeking

[108] *Opening Brief of Public Advocates Office*, filed February 12, 2021 (Cal Advocates Opening Brief), at 16. *See also*, Wagle Opening Testimony at 2-52 and Cal Advocates Reply Brief, at 6.

connection to the CAISO grid which are not dependent on the Proposed Project.[109]

The Interconnection Queue consists of interconnection requests from developers, which are regularly updated as developers complete, withdraw, or downsize their projects. The Project List identifies all the current generator requests seeking interconnection to the CAISO system. Cal Advocates essentially believes that the Proposed Project is unnecessary to meet the Commission's RPS goals.

DCRT responds that meeting the Commission's RPS goals was not the primary benefit of the Proposed Project. Rather, the Proposed Project's economic benefits alone should be the basis to grant the CPCN.

The Interconnection Queue and Project List present dynamic information about pending projects and uncertainty as to which projects will come to fruition. Given the uncertainty and the dynamic nature of the information, the Commission finds little value in the Interconnection Queue and the Project List towards the Commission's assessment of the need for the Proposed Project.

5.3.4. Cost-Effectiveness of the Proposed Project

To rebut the presumption afforded to the CAISO's economic evaluation, Cal Advocates may also show that the Proposed Project is not cost-effective. D.06-11-018 does not define the term "cost-effective." Here, we find that Cal

[109] *Brief of the Public Advocates Office on Additional Exhibits*, filed July 23, 2021 (Cal Advocates Additional Brief), at 2-3. The CAISO's Resource Interconnection Management System tracks and manages data from Interconnection Requests in the CAISO generator interconnection queue. The current version of the Interconnection Queue includes all the requests through Cluster 13. Due to the interconnection queue's large size in terms of both the number of requests and capacity, the CAISO has chosen to separately report the Cluster 14 projects. Together, the Interconnection Queue and the Project List identify all the current generator requests seeking interconnection to the CAISO system that are and are not dependent on the Proposed Project.

Advocates did not make any argument that the Proposed Project is not cost effective. Moreover, as discussed below, we find that in the grand scheme this Proposed Project is cost-effective.

Pub. Util. Code § 1002.3 provides:

> In considering an application for a certificate for an electric transmission facility pursuant to Section 1001, the commission shall consider cost-effective alternatives to transmission facilities that meet the need for an efficient, reliable, and affordable supply of electricity, including, but not limited to, demand-side alternatives such as targeted energy efficiency, ultraclean distributed generation, as defined in Section 353.2, and other demand reduction resources.

As the Commission seeks to avoid developing transmission in areas where electric resources are unlikely to develop, causing stranding of expensive transmission investments and to ensure that reality follows planning, the Commission must weigh these broad economic and public policy benefits against the monetary costs to construct the Proposed Project. Despite the disputed BCRs and assumptions in this proceeding, the Commission must consider the larger picture to meet the future needs of California ratepayers.

Moreover, all parties agree that increasing resources of renewable energy and battery capacity are necessary to meet the increasing electric demands of California ratepayers but merely dispute how that goal would be attained.

Here, aside from the calculated costs and benefits, the Proposed Project will expand the CAISO BAA and would improve opportunities for interstate commerce.[110] In consideration of the foregoing broader considerations and

[110] Exh. Cal PA-5, *Chapter 4: Arizona Transmission Policy and Planning Implications for Ten West Link (Witness: Danielle Dooley) citing to the Biennial Transmission Assessment Report* (Dooley Opening Testimony), at 4-2.

impacts of the Proposed Project, the Commission concludes that the Proposed Project is cost-effective.

5.3.5. Cal Advocates Failed to Overcome the Rebuttable Presumption in Favor of CAISO Board-Approved Economic Evaluation

As discussed above, we are not persuaded by any of the Cal Advocates' rebuttal arguments and find that Cal Advocates therefore failed to overcome the rebuttable presumption in favor of the CAISO Board-approved economic evaluation.

5.4. Conclusion

In sum, the Commission finds that the CAISO's original and updated economic evaluations are reliable in determining the necessity and cost-effectiveness of the Proposed Project, since Cal Advocates failed to overcome the rebuttable presumption here. The Commission further finds that the Proposed Project is needed and meets the requirements under Pub. Util. §1001 *et seq.*

6. Environmental Considerations

The Commission is the lead agency under CEQA, and the BLM is the lead agency under National Environmental Policy Act (NEPA) for the purposes of identifying environmental impacts of the Proposed Project. We address all environmental considerations associated with this Application and the Proposed Project in the following section of this decision.

6.1. Compliance with NEPA

BLM filed Notice of Intent (NOI) to prepare an Environmental Impact Study (EIS) for the Proposed Project under NEPA, on March 23, 2016. On April 11, 2016, the Commission entered into a Memorandum of Understanding (MOU) with the lead agency under NEPA, Federal Department of the Interior,

BLM, to act as a cooperating state agency responsible for ensuring the EIS complied with the CEQA.[111]

The Commission, with the assistance of its consultant, worked very closely with BLM to provide relevant CEQA guidance, detailed review of, and recommended revisions to, the Draft Environmental Impact Statement (DEIS) and Final EIS (FEIS), as well as detailed review and recommended revisions for all supporting technical studies and appendices, including the Appendix 1C Supplemental California Public Utilities Commission Information attached to the FEIS (CEQA Appendix).[112]

On August 31, 2018, BLM published the DEIS. The FEIS was provided to the Commission on September 12, 2019, and, thereafter, made available to the public for additional comment on October 15, 2019. The ROD was issued on November 22, 2019.[113]

6.2. Compliance with CEQA

Under CEQA, the lead agency is either the public agency that carries out the project or has the greatest responsibility for supervising or approving the project. For the Proposed Project, the Commission is the lead agency under CEQA. As the lead agency, the Commission must review and consider the

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[111] Exh. DCRT-66, *Final Environmental Impact Statement,* Appendix 1B, (FEIS Appendix 1B).

[112] *See* FEIS, Appendix 1C, *Supplement California Public Utilities Commission Information*.

[113] The ROD summarizes the environmental review process FRA conducted in accordance with NEPA, and BLM's Procedures for Considering Environmental Impacts. The ROD identifies the alternatives considered by BLM, addresses comments received during the NEPA process, and identifies the Selected Alternative. The ROD also includes a list of all measures to avoid and minimize environmental harm, including a monitoring and enforcement program to ensure adherence to these measures. Finally, the ROD presents the BLM decision, determinations, and findings regarding the Project, and identifies the factors that BLM considered in making its decision. 40 CFR §1505; 64 Fed. Reg. 28545, May 26, 1999.

environmental impacts identified in the FEIS as it relates to the Proposed Project and the CEQA requirements. [114]

The Commission further has the authority to mitigate or avoid only the direct and indirect environmental effects of the Proposed Project and must approve any mitigation measures within the Commission's jurisdiction that avoid or mitigate the environmental effects due to the parts of the Proposed Project the Commission approves, unless the changes or alterations are infeasible for specific economic, legal, social, technical and other considerations.[115] The Commission must balance any unavoidable impacts against specific economic, legal, social, technical or other benefits.

Under CEQA, unlike NEPA, we must consider "significant" environmental impacts of the proposed project when we perform the environmental review. The CEQA Guidelines provides that a "significant effect on the environment' means a substantial, or potentially substantial, adverse change in any of the physical conditions within the area affected by the project."[116] The significance criteria used for this analysis of environmental impacts are based on Appendix G of the CEQA Guidelines, as well and input from Cooperating Agencies, such as the Commission.[117] These criteria serve as a benchmark for determining if the Proposed Project would result in significant impacts when evaluated against the baseline conditions established in the EIS and Technical Environmental Study (TES).

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[114] 14 Cal. Code Regs. §15090(a).

[115] 14 Cal. Code Regs. §§ 15091(a)(2) and 15096(g).

[116] Public Resources (Pub. Res.) Code §15382.

[117] FEIS, Appendix 1C, *Supplemental California Public Utilities Commission Information* (Appendix IC), at Appendix 1C-2.

The function of Mitigation Measures (MMs) under CEQA differs from the function of MMs in the EIS under NEPA. For instance, in the EIS, mitigation can be applied to any potentially adverse effect, where feasible, regardless of the severity or duration of the effect. Under CEQA, MMs are applied to reduce potential environmental impacts to less than significant levels.[118] Under CEQA, a MM must be a specific, enforceable, feasible action that can be shown to reduce significant impacts.[119] The effectiveness of the measure should be demonstrable and capable of being monitored with specific performance standards. Unlike NEPA, MMs under CEQA are only applied to avoid or reduce impacts that would otherwise be significant.[120]

The FEIS for the Proposed Project considered the potential environmental impacts and found that the majority of the significant environmental impacts associated with the construction and operation of the Proposed Project could be mitigated and minimized to less than significant level to comply with CEQA. A copy of the MMs is included with this decision as Appendix A. No significant and unavoidable impacts were found.

On September 20, 2021, pursuant to CEQA Guidelines 15225(a), the Commission's Energy Division noticed the ALJ and the service list of this proceeding that the Commission intends to use the FEIS, including the CEQA Appendix, in lieu of preparing a separate CEQA document, environmental impact report (EIR) (September 20, 2021 Notice).

Energy Division informed the ALJ that, after reviewing the protests submitted to the BLM and in this proceeding, it continues to believe that the

[118] Pub. Res. Code §15126.4(a)(1).

[119] Pub. Res. Code §15126.4(a)(2).

[120] Pub. Res. Code §15126.4(a)(3).

FEIS, including its CEQA Appendix, meets the requirements of CEQA. Accordingly, the September 20, 2021 Notice, attached to Appendix B of this decision, is hereby marked as Exh. A and is received into the evidentiary record.

6.2.1. Environmentally Superior Alternative

CEQA Guidelines requires the identification of an "environmentally superior alternative."[121] Selection of the no project alternative would avoid all of the adverse impacts and would be the environmentally superior alternative, but none of the Proposed Project's benefits will be realized. To balance the Proposed Project's benefits with its potential adverse effects, the environmentally superior alternative among the other alternatives is Alternative 2, the BLM Utility Corridor Route, utilizing Subalternative 4D (Alternative 2-4D), which is the BLM's Preferred Alternative identified in the FEIS.[122]

Alternative 2-4D reduces adverse impacts on visual and recreational resources. Under this Alternative, the BLM would approve a total of 21.8 miles of 200-foot-wide ROW within existing designated utility corridors in California and comprised of segments selected to:

1) emphasize the use of BLM utility corridors;
2) consolidate development and disturbance with existing disturbance, such as along portions of the already impacted DPV transmission line route;
3) avoid residential and other development east and south of Blythe;
4) consolidate development along the existing DPV1 transmission line route across private lands in California; and

[121] Pub. Res. Code §15126.6(e)(2).

[122] Appendix IC at Appendix 1C-292.

5) avoid the culturally sensitive area in the vicinity of the Mule Mountains southwest of Blythe.

Alternative 2-4D also avoids impacts to sensitive cultural resources and reduce impact to visual resources in Arizona, by avoiding the King of Arizona (KofA) National Wildlife Refuge (NWR), while also avoid biological, recreation, and land use impacts associated with crossing the KofA NWR in Arizona.[123] Therefore, Alternative 2-4D would be the environmentally superior alternative under CEQA.

6.2.2. Certification of EIS

Where, as here, the project requires compliance with both CEQA and NEPA, CEQA encourages the state agency to use the NEPA document, EIS, if 1) the EIS is prepared before the state agency would otherwise prepare its own EIR, 2) the EIS complies with the provisions of the CEQA Guidelines, and 3) the EIS is supplemented to include certain CEQA requirements that are not required pursuant to NEPA.[124] Here, the FEIS was prepared before the Commission would otherwise prepare its own EIR and supplemented by the CEQA Appendix to comply with the CEQA Guidelines.

The FEIS and the CEQA Appendix was completed after notice and opportunity for public comment on the scope of the environmental review and the DEIS, as required by CEQA. The FEIS documents all written and oral comments made on the DEIS, and responds to them, as required by CEQA. The FEIS identifies MMs in the CEQA Appendix that 1) avoid or substantially lessen the environment impacts and 2) identify no significant and unavoidable environmental impacts.

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[123] *Ibid.*

[124] CEQA Guidelines § 15221; Pub. Resources Code § 21083.7.

As required by CEQA, the CEQA Appendix of the FEIS identifies Alternative 2-4D as the environmentally superior alternative pursuant to CEQA and details of the Energy Division's consideration and comparison of the combinations of Four Action Alternatives, including the environmentally superior alternative, described above, along with associated subalternatives, considered in full detail in the body of the FEIS. Action alternatives consist of individual segments that have been compiled into full Alternative Routes and Subalternatives.[125] Additionally, the CEQA Appendix of the FEIS considered the No-Project and No-Wire Alternatives. As required by CEQA (but not NEPA), the FEIS discusses growth-inducing effects in Section 5.1 of the CEQA Appendix.[126]

The Commission reviewed and considered the information contained in the FEIS and believes it meets the requirements of CEQA. The Commission certifies that the FEIS has been completed in compliance with CEQA after the Commission received, reviewed, and considered the information contained in the FEIS with the CEQA Appendix. The Commission further finds that the FEIS with the CEQA Appendix reflects our independent judgment and analysis. Accordingly, the Commission concludes that the FEIS with the CEQA Appendix sufficiently meets the CEQA requirements and is adequate for our decision-making purposes in this proceeding.

6.3. Pub. Util. Code §1002(a)

In granting a CPCN, Pub. Util. Code §1002(a) requires that the Commission must also consider the following factors: 1) community values;

[125] FEIS, Chapter 2, at 2-3.

[126] 14 California Code of Regulations (CCR) §15221.

2) recreational and park areas; 3) historical and aesthetic values; and 4) influence on environment.[127]

Pursuant to Pub. Util. Code § 1002(a)(1), we have considered the community values factor. There is no opposition from any party in this regard. FEIS demonstrates that the Proposed Project uses the existing transmission line corridor, and therefore results in only minimal impact upon any nearby communities.

Specifically, the FEIS showed that the local communities rely upon the cumulative effect area (CEA) to draw visitors to support the local economy. The FEIS also showed that, in the long run, the main unavoidable adverse effect would be the increased development in natural areas heavily used for recreation;[128] however, in the reasonably foreseeable future, actions on the undeveloped natural areas would likely have only minor cumulative effect on the recreation experience, the availability of primitive or unconfined recreational settings, and the solitude in the CEAs.[129]

Moreover, the Proposed Project also will neither displace existing housing or persons from housing nor necessitate the construction of replacement housing

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[127] Pub. Util. Code §1002(a) requires the Commission to consider, as a basis for granting a certificate of public convenience and necessity, community values, recreational and park areas, historical and aesthetic values, and influence on the environment. (See CEQA Guideline, Public Resources (Pub. Res.) Code § 15091(a), "No public agency shall approve or carry out a project for which an EIR has been certified which identifies one or more significant environmental effects of the project unless the public agency makes one or more written findings for each of those significant effects […]. The possible findings are: […] (c) Specific legal, social, technological, or other considerations, including provision of employment opportunities for highly trained workers, make infeasible the mitigation measures or project alternatives identified in the EIR.")

[128] FEIS, Chapter 4, *Environmental Consequences* (FEIS Chapter 4), at 4-126.

[129] FEIS, Chapter 3, *Past, Present, And Reasonably Foreseeable Future Projects* (CEA Projects), at 3-67.

elsewhere.[130] Specifically, the FEIS anticipates 1) no impact from construction workers requiring housing that exceeds the supply of local housing or temporary housing facilities and 2) minimal potential changes in the demand for labor or in local employment.[131]

Finally, as growth has been accounted for in various local and regional plans and projections, cumulative impacts from construction workers on the local housing market are negligible to moderate during project construction.[132] The Proposed Project, in conjunction with reasonably foreseeable energy, utility, and other infrastructure projects, could support population increases in the area in the foreseeable future.[133]

Pursuant to Pub. Util. Code § 1002(a)(2), we have also considered the issue of preservation of recreational and park areas. There is no opposition from any party in this regard. FEIS provides a detailed analysis of potential impacts to these recreational and park areas.

Specifically, FEIS also showed that the impacts to recreation and recreation areas, related to noise, dust, visual disturbance and restricted access during construction, would likely be localized and short-term.[134] FEIS projected that the reduction in recreation users coming to the area will be minor, as most users will likely move to other nearby locations not impacted by construction activities.[135]

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[130] FEIS Chapter 4, at 4-135.

[131] *Ibid*.

[132] *Ibid.*

[133] *Ibid.*

[134] *Ibid.*

[135] *Ibid*.

Ongoing operations and maintenance will have little or no long-term effect on the tourism- and recreation-related economy.[136]

Pursuant to Pub. Util. Code § 1002(a)(3), we have also considered the historic and aesthetic values. There is no opposition from any party in this regard. The Proposed Project's impacts on historical and aesthetic values and the environment were further discussed in Sections 6.2 and 6.2.1, above.

Pursuant to Pub. Util. Code § 1002(a)(4), we have considered the Proposed Project's influence on its environment in our independent review of the FEIS.

6.4. Alignment with the Commission's Environmental and Social Justice Action Plan

In February 2019, the Commission adopted the Environmental and Social Justice (ESJ) Action Plan to serve as a roadmap for implementing the Commission's vision to advance equity in its programs and policies for ESJ or disadvantaged communities.

Here, the FEIS reviewed the Proposed Project's environmental and economic impacts to ESJ communities. ESJ communities is defined in the FEIS as minority or low-income populations.[137] In California, the ESJ communities impacted are located within Riverside County, with a minority population of 61.7 percent, which is 1.5 percent greater than the state percentage.[138] The city of Blythe and surrounding area have a minority population of 70 percent with about 24 percent being low-income. Ripley, which is south of Blythe, has a 95 percent minority population with highest low-income population at

[136] FEIS Chapter 4, at 4-133.

[137] FEIS Chapter 4, at 4-136

[138] FEIS, Chapter 3, *Cultural Resources* (Cultural Resources), at 3-50.

33.7 percent.[139] In Riverside County, the land within half mile of the Proposed Project is used for commerce, recreation, residence, and agriculture.

The Proposed Project will impact a disproportionate number of the ESJ communities on a localized basis from construction, operation, and maintenance of the Proposed Project, due to the high percentage of minority population in Riverside County. These impacts would include construction noise and other disruptions and impacts to visual resources and property values during operations.[140] However, FEIS found that any impact would likely be negligible to minor due to the predominantly low population density in this rural setting and the presence of existing transmission and utility lines nearby.[141]

The Proposed Project route is adjacent or nearly adjacent to existing transmission lines, interstate highways, or other utility corridors as a means of minimizing new disturbance to either the natural or human environment.[142] Overall, the FEIS found that no short- or long-term displacement of low-income or minority businesses or residents will occur under the Proposed Project to contribute to potential cumulative effects on minority populations.[143]

Yet, ESJ communities may benefit from the short-term economic stimulus from construction activities and expenditures, short-term and longer-term increases in tax revenues, and added capacity and reduced congestion for electricity transmission.[144]

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[139] *Id.*, at 3-50-3-51.

[140] FEIS, *Executive Summary* (Executive Summary), at ES-12.

[141] *Ibid.*

[142] *Id.*, at ES-12-ES-13.

[143] *Ibid.*

[144] *Ibid*.

The Proposed Project further meets the Commission's ESJ Action Plan goals to 1) to increase climate resiliency; and 2) promote economic and workforce development opportunities in the affected ESJ communities. We note the identified negative impacts are not directly attributable to the construction of the Proposed Project in California but related to the overall project.

Upon review of the FEIS, we find that although there may be some potential and gradual negative economic and environmental impacts from the Proposed Project, the MMs, will reduce the impact to the ESJ communities to less than significant levels. The Proposed Project is also consistent with the goals set forth in the Commission's ESJ Action Plan. The Proposed Project will not result in a long-term disproportionate environmental impact upon the affected ESJ communities. Based on the foregoing, we find that the construction of the Proposed Project aligns with the Commission's ESJ Action Plan

6.5. The Commission's Third Amended Scoping Memo Did Not Materially Change the Issues Surrounding Environmental Review

Cal Advocates believes the Commission's Third Amended Scoping Memo changed the issues in scope to warrant a need to further "develop a record to assess whether the Commission reviewed and considered the FEIS and whether the FEIS reflects the Commission's independent judgment and analysis" and did not address the sufficiency of the FEIS.[145] Specifically, Cal Advocates incorrectly asserts, in its Opening and Reply Brief, an inability to address Issue 8 in the First Scoping Memo (Issue 8) and Issue H in the Third Amended Scoping Memo (Issue H) because it lacked information about the Commission review and consideration of the FEIS or whether the FEIS reflects the Commission's

[145] Cal Advocates Reply Brief, at 38

independent judgment and analysis. Cal Advocates' Reply Brief was filed on March 12, 2021, over three weeks after the Third Amended Scoping Memo was issued, and claimed "the Parties cannot take a position in the reply briefs without the Commission providing some indication as to whether it has reviewed and considered the FEIS and intends to adopt it in lieu of preparing an EIR under CEQA."[146]

Issue H did not materially change the scoped Issue 8. Both Issues 8 and H addressed the sufficiency of the EIS to meet CEQA requirements. Issue H clarifies the Commission's scope in evaluating the sufficiency of the FEIS.

The Commission's role in the EIS process is clearly stated in the Appendix 1B of the FEIS, made available to the public on October 15, 2019, which states,

> CPUC Will: (1) As the cooperating State agency, be responsible to ensure that the EIS is in compliance with all requirements of CEQA and will be responsible for the scope and content of the EIS that relates to all necessary aspects of CEQA. . .[147]

The Introduction of the 509-page CEQA Appendix to the FEIS, entitled "Supplemental California Public Utilities Commission Information" states, in relevant part:

> This appendix incorporates the environmental analysis conducted in the EIS by reference, *while providing supplemental analysis needed to address issues that may be unique to CEQA* [emphasis added]. This includes describing those environmental effects resulting from Project implementation identified in Chapter 4, Environmental Impact Analysis that may be considered significant and that cannot be mitigated to a less than significant level under CEQA. The analysis also identifies cumulative impacts, the potential to foster economic

[146] *Id.*, at 39.

[147] FEIS, Appendix 1B, at 5.

> or population growth either directly or indirectly in the Project study area and surrounding environment, and an environmentally superior alternative.
>
> Should the CPUC decide to issue a CPCN based on environmental analysis presented in the EIS, pursuant to Section 15221 of the CEQA Guidelines, the MOU provides for the CPUC's continued involvement during the Project's construction and operation phases. This involvement includes, but is not limited to, enforcement of Mitigation Measures (MMs) presented in the Mitigation Monitoring and Reporting Program (MMRP; Section 6.0).

The Introduction of the CEQA Appendix and the Appendix 1B provided the factual information necessary to analyze whether the FEIS complies with CEQA; the Commission properly reviewed and considered it; and it reflects the Commission's independent judgment and analysis as identified in Issues 8 and H.

Therefore, the Commission finds that Issue H did not materially change the scope of Issue 8 and Cal Advocates was not prejudiced by the scoped issues in the Third Amended Scoping Memo.

7. Maximum Reasonable and Prudent Cost

Pub. Util. Code §1005.5 requires the Commission, in granting a CPCN, to specify a maximum reasonable and prudent cost for the facility. The reasonable and prudent maximum cost (cost cap) for the Proposed Project was determined using the estimated anticipated construction cost, taking into consideration the design of the Proposed Project, the expected duration of construction, an estimate of the effects of economic inflation, and any known engineering difficulties associated with the Proposed Project.

CAISO originally awarded the project to DCRT subject to a cost cap of $241,805,391.[148] Since then, due to route change and a delay in in-service date, DCRT estimates the maximum reasonable cost for the Proposed Project to be $389,045,968[149] in 2021 dollars which breaks down as follows:

- Development $39,061,346
- Financing $45,024,237
- SPV – Management $26,866,199
- EPC Construction $225,664,267
- Interconnection Costs $ 52,429,919[150]

DCRT estimates an additional annual Operation and Maintenance cost of $9,700,000, including estimated property taxes.

Cal Advocates challenges the reasonableness of the cost based on its assertion that Arizona ratepayers will benefit by $2-7 million in cost savings per year from the Proposed Project and the costs of the Proposed Project should be borne by both states. Cal Advocates urged the Commission therefore to condition the approval of the CPCN for the Proposed Project upon DCRT submitting the Proposed Project for review of cost allocation under FERC Order 1000. The Commission rejects this argument because the issue of allocation of the Proposed Project costs is outside the scope of this proceeding and outside the Commission's jurisdiction pursuant to Pub. Util. Code § 9600(a)(2)(A).

Based on the evidence, we believe DCRT's updated estimates are reasonable and find that the reasonable and prudent maximum cost for the Proposed Project, including contingency, is $389,045,968 in 2021 dollars. This

[148] Unless otherwise noted, all cost figures are expressed in 2028 dollars ($).

[149] DCRT Opening Brief, at 6.

[150] Exh. DCRT-1, at. 16 and Exh. DCRT-5.

cost cap shall not be exceeded absent significant changes to the Proposed Project which cannot be anticipated at this time. The Commission finds the figures are reasonable and within expectations as the Proposed Project was initially submitted in 2016 with an expected in-service date in 2021. The Commission intends to exercise our authority to review actual costs incurred for reasonableness and prudency and to challenge them as appropriate at FERC.

8. DCRT's Request for Exemption from GOs 65-A, 77-M, 104-A is Granted in Part and Denied in Part.

DCRT requests exemptions from all annual reporting requirements under GOs 65-A, 77-M, and 104-A, due to the lack of retail customers in California as DCRT will operate as part of the CAISO system and subject to FERC review and approval. GOs 65-A, 77-M, and 104-A each concern some element of financial disclosure that utilities must regularly report to the Commission.

8.1. GO 65-A

GO 65-A, in pertinent part, requires each utility with more than $200,000 in annual gross operating revenue to file with the Commission a copy of each financial statement it prepares in the normal course of business that presents its operating results and financial condition, as well as a copy of its annual report and all other financial statements issued to its stockholders.[151]

DCRT argues that the objectives served by GO 65-A are inapplicable to DCRT "[a]s the Commission is not performing a ratemaking function with regard to DCRT" in this proceeding and should be waived. [152]

However, Cal Advocates correctly pointed out that the Commission is involved in the FERC Transmission Owner (TO) rate cases and granting

[151] GO 65-A.

[152] Application, at 32.

exemptions from the reporting requirements may impede its ability to obtain relevant and accurate information to ensure that customer interests are protected, since roughly 90% of the costs of CAISO transmission is paid indirectly through the energy rates of California retail customers.[153] Cal Advocates further argued that the exemption will prevent access to "critical information" to both Commission staff and Cal Advocates without litigation.

Although the Commission is not engaging in ratemaking in this proceeding, the Commission is a party to the ratemaking of DCRT in the FERC TO rate cases, once DCRT is fully operational. Accordingly, DCRT's request for exemption from annual reporting requirements under GO 65-A is not in the public interest to California ratepayers and is denied.

8.2. GO 104-A

GO 104-A, in pertinent part, requires each utility with more than $50,000 in annual gross operating revenue to annually file with the Commission a report identifying all persons holding a financial interest in the utility, either based upon contracts they hold with the utility or for services provided to the utility or based upon their control of ten percent or more of the voting power in the utility.[154]

DCRT believes that adhering to these reporting requirements is unnecessary, duplicative and burdensome for a transmission-only utility that is subject to (i) rate regulation by FERC, and (ii) restrictions on the costs that may be recovered in its TAC and should be waived.[155] DCRT further asserts that the

[153] *Protest of the Office of Rate Payers Advocates*, at 8.

[154] GO 104-A.

[155] Application at 32. DCRT will financial information and reports to FERC, which will be publicly available through FERC's processes.

form supplied by the Commission's Energy Division for GO 104-A annual report requires "information that complements the regulation of cost-based rates by the Commission, such as information on income statements, sales to residential customers, and related issues" which is inapplicable to DCRT, since DCRT has no retail customers and will be subject to FERC rate authority.[156]

Considering DCRT will be a transmission-only utility under the operational control of CAISO with its rates and terms and conditions of service set by FERC, DCRT is still subject to the Commission's oversight. The Commission is unconvinced that the information required under GO 104-A should be exempted. Accordingly, DCRT's request for exemption from annual reporting requirements under GO 104-A is denied.

8.3. FERC Forms 1 and 3-Q as Proxy for GOs 65-A, 104-A.

FERC Form 1, in pertinent part, requires FERC-regulated utilities to file with FERC an annual financial statement including any statement to stockholders, a balance sheet, and statements of income, retained earnings, cash flows, and related information. Among the Form 1 individual components is the duty to identify the name, title, and salary of every executive officer, but not of all other such employees making $50,000 or more annually.[157] FERC Form 3-Q, filed quarterly, is very similar to FERC Form 1 but is intended to supplement information to be provided in Form 1.[158]

DCRT, once constructed and in operation, must file FERC Forms 1 and 3-Q with FERC. FERC Forms 1 and 3-Q are, to a meaningful degree, duplicative of

[156] Application, at 32.

[157] FERC Form 1 can be found at the FERC website.

[158] FERC Form 3-Q can be found at the FERC website.

the information that is captured by GOs 65-A and 104-A. The Commission also does not foresee any change in the availability of information that would alter the Commission's ability to gauge and exercise its safety oversight authority of DCRT; raise new, additional, or different safety implications; or result in any change to the reliability of DCRT's electrical service.

The filing of FERC Forms 1 and 3-Q is also an efficient use of resources for the Commission and DCRT. First, less Commission resources may be required to track, review, and synthesize the information in the FERC forms for the Commission's purposes as a party to the FERC TO rates proceedings and as watchdog over DCRT's requested rate recovery. Second, DCRT would require less work to prepare only those forms (as opposed to also preparing GO 65-A and 104-A filings) and, therefore, avoid potentially duplicative effort.

Considering (1) DCRT is a wholesale-only utility that does not have its rates set by the Commission and is operationally controlled by CAISO, (2) the Commission's oversight of DCRT regarding safety issues will be unaffected, and (3) there will be reduction of the Commission's regulatory work burden and additional work by DCRT to prepare and file GO 65-A and 104-A information, the Commission authorizes DCRT to file its FERC Forms 1 and 3-Q filings to suffice as proxies for the financial information that would otherwise be received pursuant to GOs 65-A and 104-A filings.

8.4. FERC Form 1 and GO 77-M Requirements

GO 77-M, in pertinent part, requires each utility with more than $500,000 in annual gross operating revenue to annually file with the Commission a statement identifying the titles and duties and compensation of its executive

officers and of all employees earning more than $85,000 annually.[159] GO 77-M requires submission of data on the compensation of officers and employees, dues and donations, and legal fees.[160]

While the Commission agrees with DCRT that the "primary" purpose of GO 77-M is to assist the Commission in setting utilities' rates, the Commission has never said this is the sole purpose of GO 77-M and that, indeed, its purposes go beyond that of cost-of-service or rate-of-return ratemaking at the Commission.[161] The Commission may use all information it gleans from GO 77-M, as well as GOs 65-A and GO 104-A, in carrying out its responsible role as a party in the applicable FERC proceedings.[162]

DCRT argues that GO 77-M's disclosure requirements was unnecessary and unduly burdensome because the Commission lack jurisdiction over a DCRT's rates.[163] However, the Commission has required utilities to submit the annual reports required by General Order 77-M when FERC Form 1 is not a proxy that suffices to convey the information that would have been found in a properly completed and filed GO 77-M.[164] As explained previously, the Commission has a continuing duty to ensure that rates remain reasonable and affordable, and GO 77-M remains one tool to assist the Commission in fulfilling this duty in its responsible role before FERC.

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[159] GO 77-M.

[160] Application, at 32.

[161] D.19-07-002, at 7-9.

[162] *Ibid*.

[163] Application, at 32.

[164] D.19-07-002, at 9.

Additionally, FERC Form 1 contains a duty to identify the name, title, and salary of every executive officer making $50,000 or more annually. Given the operational size of DCRT and its parent companies, Starwood Energy and Atlantica, it is presumed that employees, who may otherwise not be disclosed in the FERC Form 1, would only have been identified and their titles, duties and their compensation described, if DCRT met the GO 77-M requirements. Based upon this observation, FERC Form 1 is clearly not a proxy that suffices to convey the information that would have been found in a properly completed and filed GO 77-M.

Although the Commission's oversight regarding DCRT is not the same as it would be for a typical utility under the Commission's full regulatory scheme, an exemption from complete compliance with GO 77-M filing requirements would pose a meaningful harm to the Commission's continued responsible roles concerning DCRT. This is because DCRT's presentation of FERC Form 1 as a proxy for compliance with GO 77-M would be inadequate, given the differences in their respective sets of information. Because the information found in FERC Form 1 does not suffice as a proxy for the information found in GO 77-M for the Commission's needs, DCRT's request for exemption from annual reporting requirements under GO 77-M is denied. DCRT must file complete information in full conformance with GO 77-M requirements.

8.5. Authorities Cited by DCRT in Support of Its Requested Reporting Exemptions are Inapposite

DCRT cites to D.00-12-030 and D.18-09-030 to support its request for full waiver of annual reporting requirements under GOs 65-A, 77-M, and 104-A. Neither decision fully exempts the reporting requirements for those applicants.

In D.00-12-013, the applicant requested exemption only from those requirements that are not applicable to a utility offering market-based rates.[165] The Commission relieved the applicant of certain reporting requirements deemed inapplicable to the applicant's operations but did not waive all annual reporting requirements.[166]

In D.18-09-030, the Commission granted a limited exemption from the annual reporting requirements under GOs 65-A, 77-M and 104-A by requiring the applicant to provide a copy of the applicant's FERC Form 1 to "facilitate providing the Commission with the vast majority of the relevant reporting information," when requested.[167]

Here, the Commission finds that D.19-07-002 is more applicable in this proceeding. In D.19-07-002, the applicant, Trans Bay Cable LLC (TBC), requested to be relieved of reporting requirements under GOs 65-A, 77-M, and 104-A.[168] TBC is a transmission-only utility with solely wholesale customers and without retail customers.

Like DCRT, TBC is under the operational control of CAISO and regulated solely by FERC for purposes of its rates and terms and conditions of service.[169] TBC owns and operates a single high voltage direct current transmission line service of approximately 400 MWs, spanning 53 miles from the town of Pittsburgh to the city of San Francisco.[170] In D.19-07-002, the Commission

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[165] D.00-12-030 (Wild Goose Decision), at 3.

[166] *Id.*, at 8.

[167] D.18-09-030, at 49.

[168] D.19-07-002, at 1.

[169] *Id.*, at 2.

[170] *Ibid.*

ordered TBC to file FERC Forms 1 and 3-Q as proxies for filings under GOs 65-A and 104-A and denied request for waiver of filing under GO 77-M.[171]

Likewise, in the instant proceeding, the Commission:

1) denies the requested exemption from the reporting requirements under GOs 65-A, 104-A and 77-M; and

2) authorizes DCRT to file the FERC Form 1 and Form 3-Q in lieu of the reporting requirements under GOs 65-A and 104-A.

9. DCRT's Request for Limited Exemption to the Affiliate Transactions Rules

The Affiliate Transaction Rules (ATRs), as initially adopted in D.94-12-088 and as set forth in D.06-12-029, were intended to establish standards of conduct for relationships between Commission-regulated gas and electric utilities and their corporate affiliates. The adopted rules create standards for non-discrimination, disclosure and information, and separation aimed at fostering competition and protecting consumers' interests.

On October 12, 2016, DCRT, in its Application, requested certain exemptions from the ATRs in order to utilize the resources available from its parent company, Starwood Energy, Atlantica and its affiliates. DCRT intends to utilize resources, personnel, and facilities of its affiliates Starwood Energy to facilitate the cost-effective financing, development, construction, ownership, operation, and maintenance of the Proposed Project.[172]

Specifically, DCRT intends to utilize resources and support of Starwood Energy and Atlantica for financing, development, and planning, environmental,

[171] *Id.*, at 14.

[172] Application, at 28.

engineering, and construction services. DCRT also intends to rely on Starwood Energy affiliate to support necessary corporate support services, such as "payroll, taxes, shareholder services, insurance, financial reporting, financial planning and analysis, corporate accounting, corporate security, human resources (compensation, benefits, employment policies), employee records, regulatory affairs, lobbying, legal, [and] pension management."[173]

In addition, DCRT also intends to rely on its affiliates for information technology, compliance, business management and planning, treasury, integrated supply chain procurement, project management, and corporate oversight and management.

9.1. Sharing of Officers and Directors

DCRT requests limited exemptions from Sections V.C., V.E. and V.G. of the ATRs, asserting that DCRT will need "from time to time to utilize certain engineering, transmission operations, employee recruiting, and marketing services from its Starwood Energy affiliates..."[174]

Section V.C. of the ATRs provides, in pertinent part:

> A utility shall not share office space, office equipment, services, and systems with its affiliates, nor shall a utility access the computer or information systems of its affiliates or allow its affiliates to access its computer or information systems, except to the extent appropriate to perform shared corporate support functions permitted under Section V E of these Rules. Physical separation required by this rule shall be accomplished preferably by having office space in a separate building, or, in the alternative, through the use of separate elevator banks and/or security-controlled access. This

[173] An energy utility and its affiliates may share these corporate support services in accordance with the affiliate transaction rules. *Affiliate Transactions Rules*, Appendix A, Rule V.E., D. 98-08-035.

[174] Application, at 29.

provision does not preclude a utility from offering a joint service provided this service is authorized by the Commission and is available to all non-affiliated service providers on the same terms and conditions (*e.g.*, joint billing services pursuant to D.97-05-039). [175]

Section V.E. of the ATRs provides, in pertinent part:

As a general principle, a utility, its parent holding company, or a separate affiliate created solely to perform corporate services may share with its affiliates joint corporate oversight, governance, support systems and personnel. […] As a general principle, such joint utilization shall not allow or provide a means for the transfer of confidential information from the utility to the affiliate, create the opportunity for preferential treatment or unfair competitive advantage, lead to customer confusion, or create significant opportunities for cross-subsidization of affiliates.[176]

[…]

Examples of services that may not be shared include: employee recruiting, engineering, hedging and financial derivatives and arbitrage services, gas, and electrical purchasing for resale, purchasing of gas transportation and storage capacity, purchasing of electric transmission, system operations, and marketing.[177]

Section V.G. of the ATRs provides, in pertinent part:

Except as permitted in Section V.E. (corporate support), a utility and its affiliates shall not jointly employ the same employees. This Rule prohibiting joint employees also applies to Board Directors and corporate officers, except for the following circumstances: In instances when this Rule is applicable to holding companies, any board member or

[175] D.98-08-035, Appendix B (Appendix B), Section V.C.

[176] *Ibid*., at Section V.E.

[177] *Ibid*.

corporate officer may serve on the holding company and with either the utility or the affiliate (but not both).[178]

DCRT believes that the limited exemptions from Sections V.C. and V.E. are necessary to "utilize the expertise and resources of DCRT's affiliates, including: (i) development support from Starwood Energy and Atlantica; (ii) development, planning, engineering, and construction support from Starwood Energy, Atlantica, and its affiliates; (iii) certain corporate support services from various Starwood Energy and ATI affiliates, whose services might not otherwise be expressly permitted under Section V.E. of the affiliate transaction rules, such as information technology, compliance, business management and planning, treasury, integrated supply chain procurement, and corporate real estate; and (iv) oversight by shared corporate officers."[179]

In D.97-12-088, the Commission cited certain objectives for adopting the ATRs, including preventing cross-subsidization between a utility's customers and the affiliate's operations, protecting the use of customer-specific information, preventing consumer confusion between the affiliate and the regulated utility, and mitigating the use of market power.[180]

DCRT has the burden to demonstrate that circumstances warrant an exemption from the ATRs. DCRT asserts that granting the limited exemptions will not lead to the risks that the ATRs were designed to protect against.

First, the costs of the Proposed Project will be recovered solely through transmission rates as part of the CAISO TAC, following approval by the FERC, which has jurisdiction over rates for interstate transmission service and will not

[178] *Id.*, at Section V.G.

[179] Application, at 29.

[180] D.97-12-088, at 11-13.

create a cross-subsidization risk that could impair competition. Since DCRT's ability to recover costs is subject to FERC approval through the ratemaking process, DCRT must implement its TO Tariff in a non-discriminatory manner and thus cannot exercise market power.[181]

Second, DCRT argues that its lack of retail customers or retail service prevents access to customer information or accounts and eliminates any "meaningful risk of consumer confusion" between DCRT and its affiliates Since DCRT does not have any retail customers in California, there is no apparent risk of customer confusion or privacy violations.

In considering the Application and supplemental response, the Commission finds that DCRT has met its burden of showing that circumstances warrant a limited exemption from Sections V.C., V.E. and V.G. With oversight by FERC for approval of DCRT's transmission rates, there is no apparent risk of cross-subsidization that could impair competition. Because DCRT is subject to open access terms in the CAISO Tariff, we do not find evidence of the potential to exercise market power. Accordingly, the Commission grants DCRT limited exemptions from Sections V.C., V.E. and V.G. of the ATRs.

10. Electric and Magnetic Field

The Commission has examined EMF impacts in several previous proceedings, concluding that the scientific evidence presented in those proceedings was uncertain as to the possible health effects of EMFs.[182] Therefore, the Commission has not found it appropriate to adopt any related numerical standards. Because there is no agreement among scientists that exposure to EMF

[181] DCRT Opening Brief, at 47.

[182] *See* D.06-01-042 and D.93-11-013.

creates any potential health risk, and because CEQA does not define or adopt any standards to address the potential health risk impacts of possible exposure to EMFs, the Commission does not consider magnetic fields in the context of CEQA and the determination of environmental impacts.

However, recognizing that public concern remains, we do require, pursuant to GO 131-D, Section X.A, that all requests for a CPCN include a description of the measures taken or proposed by the utility to reduce the potential for exposure to EMFs generated by the proposed project.

We developed an interim policy that requires utilities, among other things, to identify the no-cost measures undertaken, and the low-cost measures implemented, to reduce the potential EMF impacts.

Here, DCRT filed a Field Management Plan as Appendix F to this Application, which details the EMF measures for the Proposed Project, including the (1) utilization of a typical horizontal 500 kV tower height of 165 feet;[183] (2) installation of 500 kV transposition towers near the locations of existing transposition towers for the SCE Colorado River-Palo Verde (CRPV), formally the Devers-Palo Verde No 1 (DPV1) 500 kV transmission line;[184] and (3) use of existing utility corridors.

The record contains no other evidence or argument regarding EMF concerns. We adopt DCRT's proposed EMF reduction measures as stated in its Field Management Plan and require DCRT to comply with it.

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[183] Magnetic field models are based on both a 155-foot tower height and a 165-foot tower height. The 165-foot structures help to lower the magnetic field strength. *See* Application, *Field Management Plan for Ten West Link Transmission Project* (EMF Plan), Appendix F, at 118-120.

[184] Transposition towers are used to re-arrange the phase conductors on a transmission line; transposition structures enable magnetic field reduction as well as phase impedance equalization across the line route. EMF Plan, at 13.

11. Miscellaneous Issues

Intervenor compensation and safety considerations were two issues scoped in the First Scoping Memo. During the course of the proceeding, Conservation Group and CRIT have withdrawn from this proceeding, and TURN did not actively participate in this proceeding. Only Conservation Group and TURN filed Notices of Intent to Claim Intervenor Compensation. Therefore, the issue of guarantee of payments for intervenors' consultants and the costs of intervenor compensation is now moot.

No specific safety concern or consideration were raised. DCRT intends to operate in compliance with applicable rules, regulations, and standards governing safety, reliability, and competition.[185] The FEIS addressed public health and safety considerations, including fire, EMF, radio interference with military operations, and dust-related illness.[186] Appendix 2A of the FEIS sets forth in the APM and BMP for construction and maintenance of the Proposed Project to address safety concerns and considerations.

In granting the CPCN, the Commission adopts the APM and BMP requirements and compels DCRT to implement the APM and BMP requirements set forth in Appendix 2A of the FEIS for construction and maintenance of the Proposed Project.

12. Comments on Proposed Decision

The proposed decision of ALJ Daphne Lee in this matter was mailed to the parties in accordance with Pub. Util. Code §311 and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure.

[185] DCRT Opening Brief at 53.

[186] FEIS at 3-6, 4-9,

Comments were filed on _____, and reply comments were filed on _____ by _____.

13. Assignment of Proceeding

Genevieve Shiroma is the assigned Commissioner and Daphne Lee is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. The Proposed Project is a 125-mile 500 kV single-circuit, series-compensated, transmission line spanning between the Delaney Substation (located just north of the Palo Verde generating plant in Tonopah, Maricopa County, Arizona) and the Colorado River Substation (located west of the Arizona-California border in Riverside County, California).

2. Spanning approximately 103.5 miles in Arizona and 21.5 miles in California, the proposed route of the Proposed Project largely follows the existing DPV 500 kV transmission line and utilizes the established utility corridor, crossing Federal land, including lands managed by the BLM, Reclamation, and the YPG.

3. The Proposed Project will have a conductor capacity to transmit 3,200 MW and provide interconnection capability for new energy projects located in the region.

4. The CAISO Board, in the 2013-2014 TPP, approved the Proposed Project to provide economic benefits for California ratepayers.

5. In 2014, based on the TEAM approach, the CAISO ran two different PCM scenarios: 1) Baseline Scenario and 2) Sensitivity Scenario with updated natural gas and carbon prices.

6. CAISO's TEAM approach provided an estimated range of annual savings of $62-93 million and broken down into 1) CAISO production cost annual

savings of $41-70 million; 2) Reduction in annual transmission energy losses of $3-4 million; 3) Reduction in annual renewable curtailments of $0.3-0.9 million; and 4) Increase in annual renewable procurement of $18 million per year.

7. The production cost benefit for the Proposed Project includes three benefits to CAISO ratepayer: consumer energy cost decreases; increased LSE-owned generation revenues; and increased transmission congestion revenues. Based on these findings, the CAISO Board approved the Proposed Project in its 2013-2014 TPP.

8. The CAISO's 2013-2014 economic evaluation projected the BCR for the Proposed Project to range from 1.16 to 1.54 in the baseline analysis using the avoided cost of battery storage to quantify capacity benefits. In the higher gas price sensitivity, the range of BCR increased from 1.48 to 1.89 using the same avoided cost of battery storage to quantify capacity benefits. Using the locational renewable cost savings to calculate capacity benefits, the CAISO projected the BCR to range from 1.00 to 1.56.

9. In July 2015, the CAISO selected DCRT, as the approved project sponsor for the Proposed Project, to develop, permit, design, finance, build, own, operate and maintain the Proposed Project in accordance with the CAISO tariff.

10. The Commission recommends portfolios from the ongoing IRP process for the CAISO's annual TPP cycle.

11 In evaluating the economic benefits of the Proposed Project, the CAISO applied portfolios adopted and recommended by the Commission for the TPP of the current year.

12. When evaluating the Proposed Project, the CAISO concluded that the quantified economic and reliability benefits exceeded estimated costs. The CAISO also found additional potential benefits to include: (1) Mitigating the

impacts of higher contingency flows on neighboring systems; (2) Providing opportunities for CAISO-connected renewable generation to develop in the Delaney area; (3) Providing an increase in deliverability from the Imperial Valley zone; and (4) Increasing competition in the California generation market.

13. In 2019, the CAISO updated the economic assessment in three steps: (1) resource portfolios are developed based on the portfolios from the Commission's RESOLVE models; (2) the resource portfolios are then used to conduct production cost simulation and production benefit analysis, while using the 2019-2020 TPP with the resource portfolio is used to conduct the production cost simulation; and (3) using the results of the first two steps, the BCR for the Proposed Project was calculated based on the estimated 2021 in-service date of the Proposed Project.

14. The CAISO's updated economic evaluation considered the following specific major changes in circumstances that have occurred since the CAISO initially approved the Proposed Project: (1) Continued growth of grid-connected solar generation, in excess of the level anticipated in the 2013 timeframe; (2) Rapid deployment of distributed energy resources, e.g., rooftop solar PV, far exceeding industry expectations; (3) Decreasing battery storage costs; (4) Reducing out-of-state thermal fleet, including out-of-state coal resources; (5) Meeting LSE requirements under SB 100; (5) Accepting natural gas resources as a key resource with dispatchable capacity and critical to ensure reliability into the future, despite far less overall energy production; and (6) Advancing generation and transmission planning and development processes.

15. The CAISO believes 3262 MW of Arizona Solar can be economically selected to meet the renewable policy target and provide ratepayer production cost benefits.

16. The CAISO calculated $290.3 million in terms of present value or $17.3 million in terms of levelized annual benefits in the battery capacity benefit.

17. If the Proposed Project is not built, the CAISO calculated that the equivalent of 969 MW, or 29.7 percent of the economically-selected Arizona Solar capacity, will have to come from renewables located in less economic locations.

18. The CAISO, through the updated economic evaluation, projected the total production cost benefits to be $33.6 million annually.

19. The CAISO expects the Proposed Project will increase the amount of cost-effective, out-of-state resources in the Southwest, towards RA, from the CAISO grid-connected solar and solar-storage hybrid resources in western Arizona.

20. The CAISO's baseline scenario applied monthly natural gas price differential between Arizona South and Southern California between $0.581 to 0.597, similar to the lower end of the price differential referenced by Cal Advocates.

21. The CAISO considered the uncertainty of future systems in solar generation, in natural gas pricing and the utility-size battery costs, along with market conditions affecting the likelihood that the Proposed Project's benefits will be realized.

22. The CAISO considered alternative interconnection projects and the Palo Verde intertie when determining the economic benefits of the Proposed Project.

23. The CAISO Board made explicit findings regarding the economic value of the Proposed Project; specifically, the CAISO found quantifiable capacity and production cost benefits with reliability benefits from the Proposed Project in the baseline and sensitivity scenarios to concluded that the Proposed Project provided economic and public policy benefits.

24. The CAISO Board-approved evaluation was presented to the Commission as part of the evidence for this proceeding.

25. Based on a combination of information from the Brattle Report and three different PCM scenarios, DCRT anticipates: 1) Projected annual savings between $7 million to $36 million; 2) Reduction in curtailment of renewable generation by increasing operational flexibility of the CAISO system; 3) Increased options to integrate and access renewable energy resources to achieve the goals to reduce GHG; and 4) Increased reliability of the California and Arizona transmission network by increasing reliable power transfers in the region.

26. Although DCRT's scenarios did not analyze the impact on renewable generation interconnection, DCRT accounted for transmission congestion due to intertie scheduling limits on the CAISO's neighboring markets and additional congestion on the Palo Verde intertie during peak and overnight hours.

27. DCRT concluded that the Proposed Project will 1) increase transfer capability by 690 MW between California and Arizona, when all lines are operational; 2) allow an additional 781 MW generation to the Delaney Substation and output to southern California; and 3), transfer an additional 219 to 257 MW between Arizona and California under transmission outage conditions.

28. DCRT concluded the following economic benefits from the Proposed Project: 1) Reduced production costs and CAISO customer net payments; 2) Reduced energy losses; 3) Increased competition at the Palo Verde trading hub; 4) Increased transmission transfer capability between CAISO and APS in the EIM; and 5) Reduced RA costs.

29. DCRT anticipates the following public-policy benefits: 1) Increase the transfer capability across the Palo Verde intertie and reduce congestion and customer costs in California; 2) Unload energy across highly utilized

transmission lines to reduce energy loss, while encouraging further development of RA to connect to the Palo Verde hub to increase competition and meet RA goals for California; and 3) Expand the BAA for CAISO and APS so that both can benefit from the EIM, in addition the estimated production cost benefits.

30. Cal Advocates provided no new modeling and adjusted assumptions on solar PV development, natural gas pricing and battery capacity costs based on the Commission's portfolio from the 2019 IRP process and, thus, was not provided to the CAISO when updated economic evaluation was performed.

31. With the 2019-2020 IRP assumptions, Cal Advocates calculated a BCR between 0.55 to 0.73 and concluded that the Proposed Project, even under Cal Advocates' calculation, will result in benefits to California ratepayers, even if it is less than anticipated by CAISO and DCRT.

32. The CAISO Board-approved evaluation is consistent with the principles and minimum requirements set forth in D.06-11-018.

33. The CAISO Board approval of the updated economic evaluation is unnecessary to meet the minimum requirements under D.06-11-018.

34. The CAISO's use of the portfolios from the 2017 IRP process for the economic evaluation aligns with the transmission planning coordinated between the Commission, CAISO, and CEC.

35. The Interconnection Queue consists of interconnection requests from developers, which are regularly updated as developers complete, withdraw, or downsize their projects. The Project List identifies all the current generator requests seeking interconnection to the CAISO system.

36. Given the uncertainties and the dynamic nature of the information, the Commission finds little value in the Interconnection Queue and the Project List towards the Commission's assessment of the need for the Proposed Project.

37. The Commission weighed the economic and public policy benefits against the cost of the Proposed Project to determine the cost effectiveness of the Proposed Project.

38. BLM, as the lead agency under NEPA, prepared the FEIS in September 2019, and issued a ROD for the Proposed Project on November 22, 2019.

39. The Commission, through its consultant, prepared the CEQA Appendix, attached to the FEIS, to supplement the environmental review required under CEQA.

40. The FEIS, including its CEQA Appendix, concluded that Alternative 2-4D was the environmentally superior alternative and minimized impacts on the environment and ESJ communities.

41. The Commission received, reviewed, and considered the information contained in the FEIS with the CEQA Appendix.

42. The Proposed Project will not have any significant or unavoidable impacts that cannot be mitigated to a less-than-significant level with the MMs identified in the CEQA Appendix of the FEIS.

43. In California, the ESJ communities impacted are located within Riverside County, with a minority population of 61.7 percent, which is 1.5 percent greater than the state percentage. The city of Blythe and surrounding area have a minority population of 70 percent with about 24 percent being low-income. Ripley, which is south of Blythe, has a 95 percent minority population with the highest low-income population at 33.7 percent.

44. In Riverside County, the land within half a mile of the Proposed Project is used for commerce, recreation, residence, and agriculture.

45. The Proposed Project will impact a disproportionate number of the ESJ communities on a localized basis from construction, operation, and maintenance

of the Proposed Project, due to the high percentage of minority population in Riverside County. These impacts would include construction noise and other disruptions and impacts to visual resources and property values during operations. However, any impact would likely be negligible to minor due to the predominantly low-density rural setting and the presence of existing transmission and utility lines nearby.

46. The MMs for the Proposed Project will reduce the impacts to the ESJ communities to less than significant level.

47. The construction of the Proposed Project is expected to have some positive economic impacts to the affected ESJ communities.

48. Pursuant to CEQA Guidelines 15225(a), the Commission's Energy Division noticed the ALJ and the official service list of this proceeding, that the Commission will use the FEIS, including the CEQA Appendix, in the place of an EIR.

49. The FEIS discusses community values and recreation and park areas along with the CEA. Local communities rely upon the CEA to draw visitors to support the local economy. In the long term, the main unavoidable adverse effect is increased development in natural areas heavily used for recreation. The reasonably foreseeable future actions on the undeveloped areas will have a minor cumulative effect on the recreation experience, the availability of primitive or unconfined recreational settings, and the solitude in the CEAs.

50. The impacts to recreation and recreation areas, related to noise, dust, visual disturbance and restricted access during construction, will be localized and short-term.

51. The reduction in recreation users coming to the area should be minor, as most users will likely move to other nearby locations not impacted by construction activities.

52. Ongoing operations and maintenance will have little or no long-term effect on the tourism- and recreation-related economy.

53. The Proposed Project will neither cause existing housing or persons to be displaced nor necessitate the construction of replacement housing elsewhere.

54. As growth has been accounted for in various local and regional plans and projections, cumulative impacts from construction workers on the local housing market are negligible to moderate during Project construction. The Proposed Project, in conjunction with reasonably foreseeable energy, utility, and other infrastructure projects, could support population increases in the area in the foreseeable future.

55. The Commissioner's Third Amended Scoping Memo did not materially change Issue 8 of the First Scoping Memo; and Issue H of the Third Amended Scoping Memo clarified Issue 8 of the First Scoping Memo.

56. DCRT will be a transmission-only utility with no retail customers, owning and operating a single high voltage direct current transmission line service.

57. DCRT will be under the operational control of CAISO with rates and terms and conditions of service set by the FERC.

58. GO 65-A requires utilities with more than $200,000 in annual gross operating revenue to file with the Commission a copy of each financial statement prepared in the normal course of business which shows its operating results and financial condition, and also a copy of its annual report and other financial statements issued to its stockholders.

59. GO 77-M requires utilities with more than $500,000 in annual gross operating revenue to annually file with the Commission a statement identifying titles and duties and all compensation of executive officers and all employees who earn more than $85,000 annually.

60. GO 104-A requires utilities with more than $50,000 in annual gross operating revenue to annually file with the Commission a report identifying persons with financial interest in the utility based upon contracting with the utility or services provided to the utility or ten percent or more of voting power in the utility.

61. FERC Form 1 requires FERC-regulated utilities to file with FERC an annual financial statement including any statement to stockholders, a balance sheet, and statements of income, retained earnings, cash flows, and related information. Among its individual components is the duty to identify the name, title, and salary of every executive officer making $50,000 or more annually.

62. FERC Form 3-Q is very similar to FERC Form 1 but is intended to supplement information to be provided in Form 1 and is filed quarterly.

63. FERC Forms 1 and 3-Q provide financial and other information similar to the information necessarily provided through GOs 65-A and 104-A.

64. GO 77-M would provide the Commission with information not contained in FERC Forms 1 and 3-Q, and, therefore, FERC Forms 1 and 3-Q would not suffice as proxies to convey the information that would have been found in a properly completed GO 77-M filing.

65. DCRT's filing with the Commission of completed and accurate FERC Forms 1 and 3-Q instead of the filing required under GOs 65-A and 104-A would not interfere with, alter, or negatively impact the Commission's regulatory authority over DCRT, and may enhance the Commission's interests.

66. DCRT's filing with the Commission of completed and accurate FERC Forms 1 and Form 3-Q in lieu of reports required under GOs 65-A and 104-A would not reduce DCRT's safety or electrical service reliability.

67. DCRT intends to utilize resources and support of Starwood Energy and Atlantica 1) for financing, development and planning, environmental, engineering, and construction services; 2) to support necessary corporate support services, such as payroll, taxes, shareholder services, insurance, financial reporting, financial planning and analysis, corporate accounting, corporate security, human resources (compensation, benefits, employment policies), employee records, regulatory affairs, lobbying, legal, and pension management; and 3) for information technology, compliance, business management and planning, treasury, integrated supply chain procurement, project management, and corporate oversight and management.

68. Since DCRT's ability to recover costs is subject to FERC approval through the ratemaking process, the limited exemption from sections V.C., V.E. and V.G. of the ATRs will not create a cross-subsidization risk that could impair competition because DCRT must implement its TO Tariff in a non-discriminatory manner and thus cannot exercise market power.

69. Since DCRT does not have any retail customers in California, there is no apparent risk of customer confusion or privacy violations.

70. DCRT submitted a Field Management Plan as Appendix F to the Application, which details the EMF reduction measures for the Proposed Project, including the (1) utilization of a typical horizontal 500 kV tower height of 165 feet; (2) installation of 500 kV transposition towers near the locations of existing transposition towers for the SCE Colorado River-Palo Verde (CRPV), formally the DPV 500 kV transmission line; and (3) use of existing utility corridors.

71. All intervenors who filed a Notice of Intent to Claim Intervenor Compensation either withdrew from the proceeding or did not actively participate in this proceeding.

72. No specific safety concerns or considerations were raised. The FEIS addressed public health and safety considerations, including fire, EMF, radio interference with military operations, and dust-related illness. Appendix 2A of the FEIS sets forth in the APM and BMP for construction and maintenance of the Proposed Project to address safety concerns and consideration.

Conclusions of Law

1. DCRT should be granted a certificate of public convenience and necessity for the Proposed Project, to construct 125-mile, series-compensated 500 kV transmission line with a conductor capacity of approximately 3200 MW between the Colorado River 500 kV substation, owned by SCE, and Delaney 500 kV substation, owned by APS; and this CPCN should be conditioned upon DCRT's compliance with (a) the Mitigation Monitoring and Reporting Plan attached to this decision; (b) the EMF Field Management Plan filed as Appendix F to Application 16-10-012; (c) the APM and the BPM attached as Appendix 2A of the FEIS; and (d) all other necessary state and local permitting processes and approvals.

2. The Application and subsequent filings by the Applicant in support of the Application comply with Rule 3.1 and GO 131-D.

3. DCRT should be excused from compliance with Rule 3.1(i).

4. The CAISO Board-approved evaluation had explicit findings which are consistent with the principles and minimum requirements set forth in D.06-11-018 and was filed to the Commission within sufficient time to be included within the scope of this proceeding.

5. The CAISO's original and updated economic evaluation comply with the principles and minimum requirements under D.06-11-018 and should be presumed reliable as determination of the necessity and cost-effectiveness of the Proposed Project.

6. The Proposed Project is needed and meets the requirements under Pub. Util. §1001 et seq.

7. The Proposed Project promotes present or future safety, health, comfort, and convenience of the public to necessitate such construction.

8. The Proposed Project is cost effective.

9. Cal Advocates failed to meet its burden to rebut the presumption afforded to CAISO's economic evaluation.

10. The FEIS and its CEQA Appendix for the Proposed Project, including associated impacts and mitigations, were reviewed and are sufficient for our decision-making purposes concerning the associated environmental impacts.

11. The FEIS did not find any significant and unavoidable environmental impacts.

12. DCRT should adopt the environmentally superior alternative identified as Alternative 2-4D for the route of the Proposed Project to minimize impacts on the environment and the ESJ communities.

13. The Proposed Project, with implementation of the MMs, will have less than significant impact on the community values, recreational and park areas, historical and aesthetic values and the environment, pursuant to Pub. Util. Code §1002.

14. The FEIS is completed in compliance with CEQA requirements and reflects the Commission's independent judgment and analysis on all material matters and is adequate for Commission decision-making purposes.

15. The Commission should adopt all mitigation measures detailed in the FEIS and the CEQA Appendix.

16. The Commission should certify that the FEIS with the CEQA Appendix as adequate environmental document meeting the requirements under CEQA.

17. The Proposed Project aligns with the Commission's ESJ Action Plans goals.

18. For the Proposed Project, configured as Alternative 2-4D, the reasonable and prudent maximum cost cap is $389,045,968, including contingency.

19. DCRT should be authorized to submit properly completed FERC Forms 1 and Forms 3-Q as approximate proxies for the information it would otherwise submit to the Commission under GOs 65-A and 104-A filings.

20. DCRT should not be excused from its reporting duties under GO 77-M and should not be authorized to submit properly completed FERC Forms 1 and Forms 3-Q in lieu of GO-77 filing, because the information that would be directly conveyed to the Commission through those forms is not equivalent to all the information conveyed through a properly completed and filed GO 77-M filing.

21. DCRT should be granted limited exemptions from Sections V.C., V.E. and V.G. of the ATRs for the purpose of utilizing resources and support of Starwood Energy and Atlantica for financing, development and planning, environmental, engineering, and construction services and to support necessary corporate support services, such as payroll, taxes, shareholder services, insurance, financial reporting, financial planning and analysis, corporate accounting, corporate security, human resources (compensation, benefits, employment policies), employee records, regulatory affairs, lobbying, legal, and pension management.

22. DCRT's Field Mitigation Plan and the proposed EMF reduction measures identified therein are reasonable.

23. DCRT's proposed EMF reduction measures as stated in its Field Management Plan should be adopted.

24. DCRT should be ordered to comply with its Field Mitigation Plan and implement its proposed no-cost and low-cost measures, as identified in its Field Management Plan.

25. The issue of guarantee of payments for intervenors' consultants and costs of intervenor compensation is now moot and need not be decided.

26. The APM and BMP requirements should be adopted, and DCRT should implement the APM and BMP requirements set forth in Appendix 2A of the FEIS for construction and maintenance of the Proposed Project.

27. Motions made in this proceeding that have not been expressly ruled upon should be deemed denied.

28. This proceeding should be closed.

O R D E R

IT IS ORDERED that:

1. DCR Transmission, LLC (DCRT) is granted a certificate of public convenience and necessity to construct the Ten West Link Transmission Line Project, configured with Alternative 2-4D and conditioned upon DCRT's compliance with (a) the Mitigation Monitoring and Reporting Plan attached to this decision; (b) the Electric and Magnetic Fields Field Management Plan filed as Appendix F to Application 16-10-012; (c) the DCRT's Proposed Measures for Safety and the BLM's Required Best Management Practices attached as Appendix 2A of the FEIS; and (d) all other necessary state and local permitting processes and approvals.

2. The Commission's Energy Division may approve requests by DCR Transmission, LLC (DCRT) for minor project refinements that may be necessary

due to final engineering of the environmentally superior project, so long as such minor project refinements are located within the geographic boundary of the study area of the Final Environmental Impact Statement (FEIS) and do not, without mitigation, result in a new significant impact or a substantial increase in the severity of a previously identified significant impact based on the criteria used in the FEIS; conflict with any mitigation measure or applicable law or policy; or trigger an additional permit requirement. DCRT shall seek any other project refinements by a petition to modify today's decision.

3. DCR Transmission, LLC shall work with the Commission's Energy Division to create detailed maps for use in construction and mitigation monitoring.

4. The Final Environmental Impact Statement for Ten West Link Transmission Line Transmission Line Project is certified.

5. The maximum cost cap for the Ten West Link Transmission Line Project, configured with Alternative 2-4D is $389,045,968, including contingency.

6. Pursuant to Public Utilities Code Section 1005.5(b), at any point during the Ten West Link Transmission Line Project construction and prior to any expenditures in excess of the maximum reasonable and prudent cost determined in this decision, DCR Transmission, LLC must file a formal Petition for Modification with the Commission for consideration of a revised determination of the reasonable and prudent maximum cost of the Project.

7. DCR Transmission, LLC (DCRT) shall make quarterly information-only submittals to the Commission's Energy Division's CEQA and Federal Energy Regulatory Commission (FERC) Electric Costs teams providing status updates on the Ten West Link Transmission Project. These status updates shall include, at minimum:

a. Comprehensive project development schedule (with data organized by month), including estimated project in-service date;
b. Any changes in project scope and schedule, including the reasons for such changes;
c. Any engineering difficulties encountered in constructing the project;
d. Total estimated project costs;
e. Actual spending to date;
f. Any and all filings submitted to FERC for ultimate cost recovery through transmission rates; and
g. Any additional information DCRT believes relevant and necessary to accurately convey the status of the project.

8. Upon satisfactory completion of the Ten West Link Transmission Line Project, DCR Transmission, LLC shall file a notice of completion with the Executive Director by the Energy Division.

9. In lieu of filing reports in compliance with General Order 65-A, DCR Transmission, LLC is authorized instead to file copies of its Federal Energy Regulatory Commission Form 1 with the Commission.

10. In lieu of filing reports in compliance with General Order 104-A, DCR Transmission, LLC is authorized instead to file copies of its Federal Energy Regulatory Commission Form 3-Q with the Commission.

11. DCR Transmission, LLC must file with the Commission reports in compliance with General Order 77-M.

12. The Commission may rescind the authorization granted in paragraphs 9 and 10 above upon 60-day notice to DCR Transmission, LLC.

13. Except as otherwise ordered here, DCR Transmission, LLC must be fully compliant with every and all applicable Commission regulations and requirements.

14. DCR Transmission, LLC is granted limited exemptions from Sections V.C., V.E. and V.G. of the Affiliate Transaction Rules for the purpose of DCR Transmission, LLC using the expertise of Starwood Energy, LLC, and its affiliates.

15. All pending motions that have not been expressly ruled upon are deemed denied.

16. Application 16-10-012 is closed.

This order is effective today.

Dated _____, at San Francisco, California.