BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program.	)))))	Rulemaking 11-05-005 (Filed May 5, 2011)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) 2012 TRANSMISSION RANKING COST REPORT

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June 27, 2012

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Pursuant to the Assigned Commissioner's Ruling Identifying Issues and Schedule of Review for 2012 Renewables Portfolio Standard Procurement Plans Pursuant to Public Utilities Code Sections 399.11 et seq. and Requesting Comments on New Proposals, dated April 5, 2012, Southern California Edison Company respectfully submits its 2012 Transmission Ranking Cost Report, attached hereto as Exhibit A.

Respectfully submitted,

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/s/ Claire E. Torchia
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VERIFICATION

I am a Manager in Generation Interconnection Planning at Southern California Edison Company and am authorized to make this verification on its behalf. I am informed and believe that the matters stated in the foregoing pleading are true.

I declare under penalty of perjury that the foregoing is true and correct.

Executed this **27th day of June, 2012**, at Rosemead, California.

/s/ Jorge Chacon
By: Jorge Chacon

SOUTHERN CALIFORNIA EDISON COMPANY

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Exhibit A

SCE CONCEPTUAL TRANSMISSION REQUIREMENTS AND COSTS FOR INTEGRATING RENEWABLE RESOURCES

June 27, 2012

Southern California Edison Company

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1. Executive Summary

On April 5, 2012, the Assigned Commissioner for Rulemaking (R.) 11-05-005 issued an Assigned Commissioner's Ruling Identifying Issues and Schedule of Review for 2012 Renewables Portfolio Standard Procurement Plans Pursuant to Public Utilities Code Sections 399.11 et seq. and Requesting Comments on New Proposals (Ruling). This Ruling requires Southern California Edison Company (SCE) to prepare and file a Transmission Ranking Cost Report (TRCR). Per the Ruling, the TRCR is to be filed with the California Public Utilities Commission (CPUC) by June 27, 2012.

SCE has developed the TRCR describing renewable conceptual transmission upgrades and their associated costs based on its supplemental solicitation for information. The purpose of this TRCR is to provide necessary cost information to be used solely for evaluating renewable resource bids so that the most cost-effective bids can be selected on a total cost basis. It should be noted that in general, except where explicitly noted, the estimates in this TRCR were derived by utilizing standard off-the-shelf unit cost guides and thus should not be used for any other purpose other than bid evaluation comparison. This TRCR does not reflect the fact that SCE may not be able to satisfy the requested in-service dates due to lead times associated with permitting and constructing the necessary upgrades identified in this TRCR.

The approach utilized in this TRCR is consistent with Attachment A of CPUC Decision (D.) 04-06-013, including modifications issued in D.05-07-040. A total of 14 geographic clusters of renewable resources within the SCE service territory were identified based on renewable resources requesting interconnection via the California Independent System Operator (CAISO) and information received in response to SCE's request for supplemental information. Detailed discussions of these geographic clusters are covered in Sections 5, 6 and 7. These sections address renewable resources by counties and are grouped into Los Angeles and Kern Counties, Inyo, Mono and San Bernardino Counties, and Imperial and Riverside Counties, respectively.
The results of the TRCR are shown below in Table 1-1.

Table 1-1: Transmission Ranking Cost Report Summary

Cluster No.	Name	Cluster Totals		Estimated Capital Cost ($M)				Bid Adder (cents per kW-hr)			
		MW	GW-hrs	Level 1	Level 2	Level 3	Level 4	Level 1	Level 2	Level 3	Level 4
1	Whirlwind	3,759	9,021	$0.0	$0.102	$90	-	0	0.019	0.641	-
			MW Total	1,150	3,200	>3,200					
2	Antelope 66-kV "North" and "South"	1,264	2,738	$0.0	$2.0	-	-	0	0.030	-	-
			MW Total	0	>0	n/a	n/a				
3	Windhub/Highwind	3,534	8,907	$0.0	$4.5	-	-	0	0.019	-	-
			MW Total	2,800	4,000	n/a	n/a				
4	Antelope Area	530	1,161	$0.0	$4.5	-	-	0	0.019	-	-
			MW Total	0	530	n/a	n/a				
5	East of Pisgah	3,157	7,001	$0.0	$115	$90	$168	n/a	0.799	0.691	1.542
			MW Total	4,000	1,150	2,000	>2,000				
6	Pisgah Area	1,650	3,614	$0.0	$753	-	-	0	2.249	-	-
			MW Total	275	2,000	n/a	n/a				
7	Control Area	181	1,504	$0.0	$91.0	$195	$27.0	0	2.822	2.075	2.362
			MW Total	0	62	110	>110				
8	Inyokern Area	40	88	$0.0	$1.5	$27.0	-	0	0.027	0.287	-
			MW Total	0	40	>40	n/a				
9	Kramer Area	330	723	$0.0	-	-	-	0	-	-	-
			MW Total	1,000	n/a	n/a	n/a				
10	Victor Area	60	131	$ -	-	-	-	0	-	-	-
			MW Total	60	n/a	n/a	n/a				
11	Colorado River Area	4,716	13,823	$0.0	$180	-	-	0	0.873	-	-
			MW Total	2,000	4,000	n/a	n/a				
12	Red Bluff Area	1,800	3,942	$0.0	$90	-	-	0	1.141	-	-
			MW Total	1,050	2,100	n/a	n/a				
13	Devers 115 kV Area	318	834	$ -	-	-	-	n/a	-	-	-
			MW Total	318	n/a	n/a	n/a				
14	IID Area (Path 42)	902	6,549	$ -	-	-	-	n/a	-	-	-
			MW Total	902	n/a	n/a	n/a				

TOTAL 21,339 53,487

Note 1: Does not include sub-transmission/distribution upgrade requirements for projects requesting interconnection to (non-CAISO) radial systems

Note 2: Does not include upgrade requirements for projects requesting interconnection within IID system

2. Background

California Renewables Portfolio Standard (RPS) Program

The CPUC is continuing the implementation and administration of the California RPS program in R.11-05-005. As a successor docket to R.08-08-009, R.11-05-005 involves ongoing oversight of the RPS program, including review of RPS procurement plans, reporting, and compliance, as well as implementation of the amendments to the RPS program recently enacted by the Legislature.

The RPS program seeks to increase the amount of California's electricity generated from renewable resources to provide benefits to the State including, but not limited to: displacing fossil fuel consumption, adding new electric generating facilities within the Western Electricity Coordinating Council service area, reducing air pollution, meeting the State's climate change goals, meeting the State's need for a diversified and balanced energy generation portfolio, contributing to safe and reliable operation of the electrical grid, assisting in meeting the State's resource adequacy requirements, and promoting stable retail rates for electric service.

Senate Bill (SB) 2 (1x) was enacted in the First Extraordinary Session of the Legislature on April 12, 2011, and became effective on December 10, 2011. SB 2 (1x) made significant changes to the RPS program, including departing from the prior structure of annual RPS goals and moving to multi-year compliance periods. The overall percentage of required procurement from eligible renewable energy resources for all retail sellers was also increased from 20% to 33%, with interim procurement targets established for each multi-year compliance period.[1]

The eligibility of renewable energy resources is determined by the California Energy Commission (CEC), and may include the following technologies: photovoltaic, wind, geothermal, solar thermal, biomass, digester gas, landfill gas, small hydroelectric, ocean wave, ocean thermal, tidal current, fuel cells using renewable fuels, and use of municipal solid waste. A retail seller is an entity engaged in the retail sale of electricity to an end-use customer located in California. Retail sellers include electrical corporations, community choice aggregators (CCAs) and electric service providers (ESPs).

[1] In particular, as implemented by the CPUC in D.11-12-020, the new RPS procurement quantity requirements applicable to all retail sellers are as follows: (1) 20% of overall retail sales for the first compliance period from 2011-2013; (2) 21.7% of 2014 retail sales plus 23.3% of 2015 retail sales plus 25% of 2016 retail sales for the second compliance period from 2014-2016; (3) 27% of 2017 retail sales plus 29% of 2018 retail sales plus 31% of 2019 retail sales plus 33% of 2020 retail sales for the third compliance period from 2017-2020; and (4) 33% of retail sales in each year thereafter.

CPUC Procedural Background

On August 22, 2001, in anticipation of the passage of SB 1078, the CPUC ordered the three major utilities to solicit electricity generated by renewable resources in an amount of at least an additional one percent of the utility's actual energy and capacity needs.[2] The CPUC began specific implementation of the RPS legislation in R.01-10-024 upon SB 1078 becoming effective. As required by the Legislature, within six months the CPUC adopted the first of several decisions to set initial parameters and requirements for the RPS program.[3]

In April 2004, the CPUC opened R.04-04-026 to continue implementation of the RPS program. In anticipation of closing R.04-04-026 (which was closed in May 2006), the CPUC opened R.06-02-012 in February 2006. This permitted continuing work on several specific RPS matters.

To create a vehicle for more generalized ongoing implementation and administration of the RPS program, the CPUC then opened R.06-05-027 in May 2006. Several matters were addressed in R.06-05-027, which closed in August 2008.

Subsequently, the CPUC opened R.08-08-009 in August 2008 as the successor to R.06-05-027. This proceeding involved ongoing oversight of the RPS program, including review of RPS procurement plans, reporting, and compliance. It also included consideration of limited policy issues related to ongoing RPS program implementation and administration.

In May 2011, the CPUC closed R.08-08-009 and opened R.11-05-005 to continue implementation of the RPS program, as well as to implement the amendments to the RPS program enacted by the Legislature in SB 2 (1x). The April 5, 2012 Ruling requires SCE to prepare and file a TRCR by June 27, 2012.

Request for Supplemental Information from Eligible Renewable Developers

In the April 5, 2012 Ruling, the Assigned Commissioner for R.11-05-005 required SCE to send a letter to prospective developers of eligible renewable energy projects who may participate in the State's RPS program requesting information to be used in its TRCR. The purpose of the supplemental information is to assist in developing necessary transmission plans to properly integrate eligible renewable energy projects. SCE sent its letter to prospective developers on April 11, 2012. This report includes the supplemental information obtained in response to SCE's letter request. An overview of the responses from renewable developers is described in Section 3 of this report.

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[2] D.02-08-071.

[3] D.03-06-071.

CAISO Generation Interconnection Process Overview

The foundation for the current CAISO generation interconnection process was established by the Federal Energy Regulatory Commission (FERC) in Order No. 2003 and its progeny. The Large Generator Interconnection Procedures (LGIP) tariff has successfully ensured open transmission access for new generation interconnection customers. However, over the past few years, several factors, largely unanticipated at the time of Order No. 2003's adoption, including the very large number of interconnection requests for renewable generation, have imposed significant challenges to the efficiency of a "serial" generation interconnection study approach.

On May 15, 2008 the CAISO filed with FERC a petition for waiver of provisions of the LGIP to facilitate the transition to a reformed generation interconnection process. This waiver petition was the initial step in a two-step process to reform the LGIP to allow the CAISO to manage its interconnection queue more efficiently and to be consistent with the development timelines of transmission assets needed to ensure reliability and compliance with California's RPS requirements. FERC granted the CAISO's petition for waiver on July 14, 2008. On July 28, 2008 the CAISO filed with FERC a proposed amendment to the CAISO Tariff. In this proposed Generation Interconnection Process Reform (GIPR) tariff amendment, the CAISO proposed changes to its large generator interconnection process, interconnection agreements and related portions of the CAISO Tariff to achieve the goals identified and discussed in the GIPR stakeholder process. On September 26, 2008, FERC issued a ruling conditionally approving the CAISO's proposed GIPR tariff amendments. In November 2008, the CAISO submitted further tariff revisions to comply with the September 2008 order. On September 18, 2009, the CAISO filed with FERC an additional request to revise specific portions of its LGIP for interconnection requests in a queue cluster window.

In essence, new generator interconnection requests to CAISO for projects greater than 20 MW are now processed under the CAISO tariff Appendix Y, "Large Generator Interconnection Procedures (LGIP) for Interconnection Requests in a Queue Cluster Window." In this process, generation interconnection requests for projects greater than 20 MW are processed together in clusters and each cluster undergoes a two-phase interconnection study process. A specific Transition Cluster (TC) with specific timelines was defined for purposes of facilitating the transition from the old serial interconnection study process to the new cluster study process. After the TC, cluster studies moving forward began on a regular schedule every six months, starting in beginning and middle of each calendar year. Note that generation interconnection projects that are less than or equal to 20 MW in size were still processed under the CAISO tariff Appendix S, "Small Generator Interconnection Procedures" (SGIP) which remains a serial interconnection process conducted in parallel with the LGIP.

There was a substantial increase in the number of projects requesting interconnection under the SGIP process. Therefore, on October 19, 2010, the CAISO filed with FERC a proposed tariff revision to its generation interconnection process. The proposed revision, generator interconnection procedures (GIP), was intended to harmonize the CAISO's

LGIP and its SGIP. This proposal addressed the inefficiencies in the CAISO LGIP process for interconnecting small generators by adopting an integrated cluster study process for both small and large generators. The CAISO proposed to split current SGIP requests into two groups. The SGIP serial study group would include projects with valid interconnection requests submitted prior to December 19, 2010, the requested effective date of the GIP, that had executed a system impact study or facilities study agreement providing for the completion of such studies by December 19, 2010. The second group, the SGIP transition cluster, would include projects with valid interconnection requests submitted prior to December 19, 2010 that did not have executed a system impact study or facilities study agreement providing for the completion of such studies by December 19, 2010. On December 16, 2010, FERC issued a ruling conditionally approving the CAISO's proposed tariff revisions. The interconnection process continues to be updated.

The amount of queued renewable generation in the CAISO interconnection queue far exceeds the amount of renewable generation that would be required to meet the State's RPS targets. However, per FERC interconnection protocols all projects in queue, renewable or non-renewable, must be treated on an equal basis. Queue Cluster 3 and 4 Phase 2 studies are ongoing and are scheduled to be completed in late 2012. Furthermore, the Phase 1 studies for Queue Cluster 5 are expected to be commenced by third quarter 2012, and these studies are scheduled to be completed in the first half of 2013.

The CAISO developed an alternative methodology to the Phase 1 analysis of the network upgrades for interconnection Queue Cluster 4 to determine the interconnection customer's cost responsibility. This alternative methodology was established out of a concern that, if the current methodology was used in Queue Cluster 4, Phase 1, unrealistic mitigation requirements would result due to the high volume of generation interconnection requests relative to renewable procurement requirements. This alternative considers studying a more realistic amount of expected generation based on the greater of the generation requests studied in Queue Cluster 3, Phase 1, or the highest generation forecast in any of the CPUC Long Term Procurement Plan (LTPP) renewable generation portfolios. The delivery network upgrade cost ($/MW) results associated with these assumptions was used across all the Queue Cluster 4 generation that has applied for interconnection in the study area.

This TRCR and the bid adders calculated are based on the best information available today and utilizes, where appropriate, the most recently completed interconnection studies for projects in the interconnection queue. Future TRCR analysis may yield different results based on the highly dynamic nature of the CAISO interconnection process and the CAISO interconnection queue.

Information related to the current CAISO generation interconnection process can be found at http://www.caiso.com/docs/2002/06/11/2002061110300427214.html.

3. Response to Request for Supplemental Information

Pursuant to the April 5, 2012 Ruling, SCE sent out a letter on April 11, 2012 to renewable energy developers requesting that they provide additional information regarding transmission. The deadline for interested parties to respond to this supplemental solicitation for information was April 30, 2012.

Twenty-eight different developers responded to SCE's supplemental information request. These developers identified up to one hundred and seven potential renewable resource projects and one transmission line interconnection which will support out-of-state wind generation projects. These requests include forty-three in SCE's service territory (total of 13,868 MW) and sixty-five outside of SCE's service territory (total of 10,628.7 MW). Of these one hundred and eight total projects, forty-seven were identified as solar (either solar thermal or solar PV), nineteen were identified as wind, and forty-two were identified as geothermal.

There are a significant number of renewable generation projects pursuing interconnection via the CAISO interconnection process. Per FERC generation interconnection protocols, these projects were given first priority in developing conceptual transmission upgrades, regardless of whether the queued generation was renewable or non-renewable in nature. Even with this, the majority of projects in the CAISO interconnection queue are renewable, and the MW totals associated with projects in queue far exceed the MW totals identified in the supplemental request for information, and many of the projects identified in the supplemental solicitation were found to be active projects in the CAISO interconnection queue.

The definition of facility upgrades in SCE's Eastern and Northern areas for purposes of this TRCR relies primarily on recently completed queue cluster interconnection studies for several reasons. First and foremost, the transmission facilities that were identified in the Queue Cluster 3 Phase 1 studies were generally assumed to create sufficient capacity to accommodate the additional non-queued generation projects identified in the supplemental request for information. In addition, not all the Queue Cluster 3 Phase 1 projects proceeded on to the Phase 2 studies that have just commenced, and the impact of such withdrawals could be assumed to somewhat offset the impact of those non-queued projects identified in the supplemental solicitation. Therefore, the facilities for interconnection of queued generation as identified in the Queue Cluster 3 Phase 1 played a significant role in determining bid adders for renewable generation in these two areas.

For SCE's East of Lugo and North of Lugo areas, conceptual upgrades were developed as Queue Cluster 3 studies did not provide adequate information for this TRCR.

4. Study Limitations

SCE believes that the information presented in this revised conceptual transmission plan fulfills the Methodology for Development and Consideration of Transmission Costs as described in Attachment A of the 2004 Interim Opinion Order (D.04-06-013) issued on June 9, 2004, as well as the modifications identified in the 2005 Interim Opinion Regarding Transmission Costs in RPS Procurement (D.05-07-040) issued on July 21, 2005. SCE's TRCR presents the estimated cost for the revised conceptual transmission network upgrades needed to accommodate the interconnection and delivery of generated power from all renewable resource projects received in response to SCE's solicitation for information, as well as the renewable resources currently progressing through the FERC-mandated generation interconnection process.

This study is not without limitations. The most significant limitation of this TRCR is associated with the sheer size of the existing CAISO interconnection queue. There was over 39,000 MW of queued renewable generation projects (serial thru Cluster 3 and 4 Phase 2) that were considered as part of this year's TRCR analysis. To put this number into perspective, this renewable generation capacity "proposed" by developers in queue exceeds the total summer peak customer demand served throughout the entire SCE service territory. It is extremely difficult to envision a comprehensive set of "conceptual" transmission upgrades that can accommodate all of these renewable projects currently in the interconnection queue.

An unfortunate consequence of this queue size it is extremely difficult to develop appropriate conceptual schedules for phasing of upgrades to interconnect renewable generation projects. Previous TRCRs have considered conceptual schedules for the phasing in of upgrades based on three sources of renewable development timelines: (a) the CEC Electric Transmission Plan for Renewable Resources in California dated December 1, 2003, (b) developer-requested in-service dates for active renewable projects in the generation interconnection queue, and (c) developer-identified in-service dates for projects identified in the supplemental solicitation for information for consideration in the TRCR.

SCE's experience in recent years is that the 2003 CEC report is becoming more outdated and less relevant for ongoing annual TRCR purposes, particularly as actual renewable generation projects materialize through the CAISO interconnection process. In regards to developer-requested operating dates, tracking such interconnection dates is becoming a highly complex process based on the sheer number of active projects in the interconnection queue. It is not practically possible to do so in an abbreviated and conceptual assessment like this TRCR. There is also a growing problem of disconnects between "developer-requested" operating dates (generally provided to SCE and CAISO at the commencement of an interconnection study) and "feasible" operating dates (generally determined through detailed operating studies performed during the course of an interconnection study) that make use of developer-requested dates less and less appropriate for TRCR purposes. Finally, the transmission upgrades identified in this TRCR are generally "major" transmission projects. Recent SCE experience with

comparable projects under development has shown that project development timelines and the phasing of such upgrades are highly dependent on permitting and licensing timelines, and such permitting and licensing timelines are extremely difficult to conceptualize in a meaningful way in an assessment like the TRCR.[4]

The bid adder results in this report provide, based on the best information available today, a relative comparison of transmission requirements in various geographic clusters for the interconnection of renewable resources in the SCE transmission system. In other words, the transmission bid adders presented in this report should only be considered in relative comparison to other transmission bid adders also presented in this report. This TRCR also has additional limitations, including, but not limited to the following:

1. Exact location and project generators' specifications are not fully available.

2. The TRCR is not a part of the FERC interconnection process which must be followed by all renewable bidders in order to be interconnected to the existing system.

3. Detailed queue cluster studies (Phases 1 and 2) for each GIP renewable project need to be performed to identify the actual impacts of the project on the existing electric system, the facilities required to interconnect the project(s), the schedule for the phased implementation of those facilities, and to properly engineer, design, and estimate actual costs of such facility upgrades that are required.

4. Detailed substation site review is needed to properly identify suitable locations.

5. Detailed right-of-way review is needed to identify right-of-way requirements.

6. Detailed environmental assessments need to be performed for new sites and new line routes proposed, including alternatives for the substation sites and transmission line routing, as well as proposed mitigation measures.

7. Plan of service identified will likely change based on a number of factors including, but not limited to, the results of detail interconnection studies, results of substation site review and results of detailed environmental review.

8. Cost estimates were prepared utilizing standard off-the-shelf unit-cost guides which can have an accuracy of plus/minus forty-percent.

9. Feasibility of meeting proposed project requested in-service dates was not validated.

10. Renewable integration and operational issues were not considered.

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[4] The task of performing operating studies for purposes of planning the phased implementation of upgrades is an element of the detailed Phase 2 (not the more general Phase 1) interconnection cluster studies.

11. Projects located in areas not addressed in this TRCR should utilize their specific interconnection study results corresponding to such projects to develop appropriate bid adders.

These limitations will affect the scope of facilities, the phasing of the identified facilities, cost, and the viability of the transmission plans identified in this revised conceptual study to be used for the purpose of obtaining adequate transmission bid adders.

Section 5

LOS ANGELES AND KERN COUNTIES SCE CONCEPTUAL TRANSMISSION REQUIREMENTS AND COSTS FOR INTEGRATING WIND RESOURCES

5-1. Introduction

SCE revised its previous conceptual transmission studies to incorporate supplemental information received from various renewable resource developers and the latest information regarding the Antelope Transmission Project (ATP) and the Tehachapi Renewable Transmission Project (TRTP) formulated as part of the CAISO South Regional Transmission Plan. The supplemental information obtained was in response to SCE's request for additional information from potential renewable energy bidders. This information was used in conjunction with current generation projects (both renewable and non-renewable) requesting interconnection via the CAISO interconnection process and with previously identified renewable resource potential in the CEC's Electric Transmission Plan for Renewable Resources in California Report to the Legislature dated December 1, 2003.

This section presents the revised conceptual transmission plan and corresponding transmission cost estimates necessary to accommodate the renewable resources located in Los Angeles and Kern Counties.

5-2. Renewable Resources

The renewable resources identified by the CEC in 2003 included a total of 4,475 MW of renewable generation by 2017.

There are a total of sixty-eight generation interconnection projects totaling 9,146 MW in the CAISO interconnection queue in this area thru Cluster 4. This includes renewable wind generation projects, (4,657 MW), solar projects both solar thermal and photovoltaic (3,911 MW), and other generation projects (578 MW). In addition, there are a total of one hundred and thirty-seven generation projects seeking interconnection under the WDAT and Rule 21 interconnection processes. This includes renewable wind generation projects, (33 MW), solar projects both solar thermal and photovoltaic (592 MW), and other generation projects (137 MW).

These interconnection applications reflect significantly more renewable generation development than was forecast by the CEC in 2003. Since renewable generation applications in the CAISO interconnection queue far exceed the renewable resources identified by the CEC, it was assumed that the CEC forecast potential was a subset of the total interconnection queue. Therefore, bid adder analysis was based on queued projects and supplemental information and did not explicitly consider the CEC forecast.

There was one project in the supplemental responses from renewable developers in the area of interest that is not in the CAISO interconnection queue prior to Queue Cluster 4 (request is part of the Queue Cluster 5). The total capacity of the project (150 MW) is significantly less than the overall capacity of active generation interconnection requests through Queue Cluster 4 (9,916 MW). It was assumed that upgrades identified in the Queue Cluster 3 Phase 1 study would generally be sufficient to accommodate the incremental additional projects identified in the supplemental responses from renewable developers.

5-3. Study Assumptions and Study Methodology

Study Assumptions

1. Interconnection Facilities

   All the resources identified above are divided into four general areas: 1) resources requiring 230 kV or higher interconnection that are located near Rosamond Avenue and 170th Street West (the Whirlwind Substation area), 2) resources requiring 66 kV interconnection in and around Tehachapi (the Antelope 66-kV "North " area) and generally located south of Rosamond Boulevard (the Antelope 66-kV "South" area), 3) resources requiring 230 kV or higher interconnection in and around Tehachapi (the Windhub/Highwind Substation area), and 4) resources requiring 230 kV or higher interconnection in the area generally near Highway 14, city of Lancaster and city of Palmdale (the Antelope Substation area).

   It was assumed that all wind generation projects would be interconnected to the SCE system by constructing new gen-tie facilities to existing or planned substations, transmission lines, or sub-transmission lines, and the costs of these gen-tie facilities were not derived. The cost for these facilities should be included into the corresponding bids.

   The associated costs of interconnection facilities that are deemed to be Location-Constrained Resources Interconnection Facilities (LCRIF) and which are anticipated to be upfront funded by SCE, with the generators utilizing such facilities paying back a pro-rata share of the revenue requirement on an Added Facilities basis were not included in this analysis and should be reflected by each developer into the corresponding bids if applicable.

2. Network Facilities

   SCE will be upfront financing the costs of reliability and delivery upgrades associated with the TRTP and the Whirlwind Expansion. As such, the costs of these upgrades have not been included in this TRCR analysis.

   Delivery of the energy from Tehachapi will require upgrades to existing network facilities. Generally speaking, the closer the renewable resource is located to the

load centers, the lower the number of upgrades to transmission facilities would be required. In the case of the Tehachapi area wind generation, the location of these renewable resources is such that delivery to the utility load centers will necessitate significant network upgrades.

Study Methodology

Modifications to the previous TRCR were made due to the significant amount of generation projects that have requested interconnection since last year and the recently completed Cluster 3 Phase 1 interconnection study. Bid adders are derived by taking the total project cost for identified transmission system upgrades and spreading the cost for each element or upgraded facility among the projects in the cluster(s) that require those upgrades. The assumptions made with regard to capacity factor are as follows:

- 30 percent for wind generation
- 25 percent for solar generation
- 25 percent for PV generation
- 50 percent for non-renewable

Deliveries to San Diego Gas & Electric Company (SDG&E) were assumed at the existing San Onofre 230-kV substation. It should be noted that such deliveries could necessitate an increase in import capability for SDG&E, as well as an increase in transmission capacity to the SDG&E load center. Such increases could be achieved by upgrading south of San Onofre (Path 44) capability or by developing additional SCE-SDG&E system ties. See SDG&E Conceptual studies for further details.

Deliveries to SDG&E and SCE load centers both necessitate transmission capacity South of Vincent. With TRTP, the total South of Vincent transmission capability will increase from 4,000 MW to approximately 8,500 MW. This TRCR assumes all new resources executing power purchase agreements (PPAs) with SCE and SDG&E will fit within this South of Vincent capability. If more than 8,500 MW of South of Vincent transmission capacity is ultimately required, additional upgrades involving constructing 500 kV Transmission from the Gould substation area to Mesa Substation converting Mesa into 500 kV Substation and utilizing TRTP transmission to complete 500 kV transmission connection would be needed. Detailed studies to be performed as part of the generation interconnection process may determine that such additional South of Vincent upgrades for projects examined with this report's bid adder is required.

Deliveries to Pacific Gas and Electric Company (PG&E) were assumed at the existing Midway 500-kV substation assuming the existing Path 26 transmission facilities including a new Tehachapi-Midway 500 kV transmission line that can accommodate such increase in imports into PG&E. It should be noted that such deliveries could necessitate an increase in transmission capacity to the PG&E load center. Such increases can be achieved by additional Path 15 reinforcements. See PG&E Conceptual studies for further details.

5-4. Description of Transmission Upgrades

The following are descriptions of the transmission upgrade facilities needed to interconnect and deliver generation resources for the renewable resources identified in the Tehachapi area.

Upgrades associated with ATP and TRTP

Details related to the scope of ATP (A.04-12-007 and A.04-12-008) and TRTP (A.07-06-031) can be found at http://www.cpuc.ca.gov/puc/energy/environment/current+projects and by following the appropriate links.

Upgrades Beyond ATP/TRTP

With all of the ATP and TRTP upgrades in place to accommodate up to 4,500 MW of queued interconnection requests, significant additional upgrades will be required to accommodate the remaining queued projects and the supplemental responses from renewable resource developers. These upgrades include the following:

Whirlwind Substation Area

- Expansion of the Whirlwind Substation 230 kV bus
- Installation of additional Whirlwind 500/230 kV transformers
- Installation of Special Protection System (SPS) for transmission line and/or transformer contingency overloads

Antelope 66-kV North and South Areas

Projects that request interconnection to 66 kV facilities that are currently under CAISO control may require subtransmission system upgrades. These 66 kV facilities will be converted to non-CAISO facilities upon completion of SCE's East Kern Resource Wind Area (EKRWA) project. Costs associated with upgrades to non-CAISO controlled facilities are typically the cost responsibility of the developer and not subject to refund. These costs can vary greatly depending on the specific location, size of the project, and subtransmission or distribution system infrastructure in that area. Furthermore, these upgrades are typically very specific to individual generation projects and do not accommodate large numbers of projects (i.e., the upgrades are typically not common to all projects in any given cluster). As such, this TRCR did not identify any subtransmission upgrades and did not include a corresponding subtransmission bid adder for these two areas. Consequently, the costs for subtransmission upgrades need to be addressed on a project-by-project basis and should be reflected by each developer into the corresponding energy bid, if applicable.

Windhub/Highwind Substation Area
Installation of SPS for transmission line and/or transformer contingency overloads in the Windhub/Highwind Area.

Antelope Substation Area
Installation of SPS for transmission lines contingency overloads in Antelope Area.

All Northern Areas

Any "South of Vincent upgrade" would be common to all Northern geographic areas. As part of this TRCR, the only South of Vincent upgrade identify involves replacement of the Lugo-Vincent 500 kV T/L Wave traps.

5-5. Transmission Project Cost Estimates for Bid Evaluation

Facilities for all Clusters below

Some projects located in the Northern Areas discussed below will need to share the cost of the Lugo-Vincent 500 kV transmission lines wave traps. Specifically, the projects identified under Level 2 and Level 3 in the clusters discussed below.

The total estimated capital cost of all of these upgrades is approximately $2.0 million, with an estimated carrying charge of approximately $0.31 million. The bid adder is derived by taking the total estimated project costs for the above upgrades and spreading the costs throughout the specific generation in the area that would require these facilities. Based on the estimated capital costs of these facilities and the estimated energy production of queued generation projects, the bid adder for this upgrade is approximately 0.003 cents per KWH. This bid-adder will be included in the bid adder for each cluster below as appropriate.

Facilities for Cluster 1 (Whirlwind)

Cluster 1 Level 1: Up to 1,150 MW

Level 1 represents the available capacity on the system with the inclusion of ATP and TRTP.

Bids associated with active serial interconnection projects explicitly defined to be part of the Tehachapi Queue Cluster (TQC) in the Tehachapi Wind Resource Area (TWRA) should be assigned a zero bid adder due to SCE commitment to upfront finance the ATP and TRTP upgrades. All other non-TQC projects in the area should be given a bid adder based on Cluster 1 Level 2 below. For additional details related to the TQC, see the FERC decision which can be found at http://www.caiso.com/1bee/1bee799b1f1f0.doc.

Cluster 1 Level 2: 1,151 MW up to 3,200 MW

Level 2 represents the available capacity after the inclusion of TRTP and Whirlwind Expansion. Resources in this level will require the use of an SPS for which a bid adder is assigned. A brief description of these upgrades is provided in Section 5-4 above.

The total estimated capital cost of all of these upgrades is approximately $4.5 million, with an estimated carrying charge of approximately $0.72 million. The bid adder is derived by taking the total estimated project costs for the above upgrades and spreading the costs throughout the total generation in the area (including generation in other areas as necessary) that would require these facilities and adding the shared bid adder derived above. Based on the estimated capital costs of these facilities and the estimated energy production of queued generation projects, the bid adder for projects in this level including the common bid adder discussed above is approximately 0.019 cents per KWH.

Cluster 1 Level 3: Beyond 3,200 MW (upper limit unknown at this time)

Level 3 provides a bid adder for resources at Whirlwind which are in excess of 3,200 MW as additional upgrades beyond what SCE is upfront financing are necessary. Primarily, the fourth 500/220 kV transformer bank at Whirlwind would be required.

The total estimated capital cost of the fourth transformer bank is approximately $90 million, with an estimated carrying charge of approximately $14.4 million. The bid adder is derived by taking the total estimated project costs for the above upgrades and spreading the costs throughout the total generation in the area (including generation in other areas as necessary) that would require these facilities. Based on the estimated capital costs of these facilities and the estimated energy production of queued generation projects, the bid adder for projects including the common bid adder discussed above is approximately 0.641 cents per KWH.

<u>Facilities for Cluster 2 (Antelope 66-kV “South and North”)</u>

Cluster 2 Level 1: 0 MW

Level 1 represents the available capacity on the existing 500 and 220 kV system without any upgrades. All Level 1 capacity in the Northern Area is assumed to be utilized by resources located within Cluster 1 and 4.

Cluster 2 Level 2: Beyond 0 MW (upper limit unknown at this time)

While subtransmission upgrades may be necessary to support projects in queue, these upgrades are not identified in this TRCR. However, these Clusters will share in the upgrades identified for all Northern Areas. See Section 5-4 for additional details.

The total estimated capital cost of all of these upgrades is approximately $2.0 million, with an estimated carrying charge of approximately $0.31 million. The bid adder is derived by taking the total estimated project costs for the above upgrades and spreading

the costs throughout the total generation in the area (including generation in other areas as well) that would require these facilities. Based on the estimated capital costs of these facilities and the estimated energy production of queued generation projects, the bid adder for projects is approximately 0.003 cents per KWH

Facilities for Cluster 3 (Windhub/Highwind)

Cluster 3 Level 1: Up to 2,800 MW

Level 1 represents the available capacity on the system with the inclusion of ATP and TRTP.

Bids associated with active serial interconnection projects explicitly defined to be part of the Tehachapi Queue Cluster (TQC) in the Tehachapi Wind Resource Area (TWRA) should be assigned a zero bid adder due to SCE commitment to upfront finance the ATP and TRTP upgrades. All other non-TQC projects in the area should be given a bid adder based on Cluster 1 Level 2 below. For additional details related to the TQC, see the FERC decision which can be found at http://www.caiso.com/1bee/1bee799b1f1f0.doc.

Cluster 3 Level 2: 2,801 MW to 4,000 MW

Level 2 represents the available capacity after the inclusion of TRTP. Resources in this level will require the use of an SPS for which a bid adder is assigned. A brief description of these upgrades is provided in Section 5-4 above.

The total estimated capital cost of all of these upgrades is approximately $4.5 million, with an estimated carrying charge of approximately $0.72 million. The bid adder is derived by taking the total estimated project costs for the above upgrades and spreading the costs throughout the total generation in the area (including generation in other areas as well) that would require these facilities. Based on the estimated capital costs of these facilities and the estimated energy production of queued generation projects, the bid adder for projects including the common bid adder discussed above is approximately 0.019 cents per KWH.

Cluster 3 Level 3: Beyond 4,000 MW

Level 3 will require the installation of a new 500/220 kV Substation in the area. This TRCR does not provide a bid adder for such new facilities based on the assumption that the amount of new resources to ultimately develop in the Windhub/Highwind Area will be below the 4,000 MW threshold. However, detail studies to be performed as part of the generation interconnection process may determine that an additional substation is required. As such, all bids in this area will be limited to the bid adder provided for Level 2.

Facilities for Cluster 4 (Antelope)

Cluster 4 Level 1: 0 MW

Level 1 represents the available capacity on the existing system without any upgrades. All Level 1 capacity in the Northern Area is assumed to be utilized by resources located within Cluster 1 (Whirlwind) and Cluster 3 (Windhub/Highwind).

Cluster 4 Level 2: Beyond 0 MW (upper limit unknown at this time)

Level 2 provides a bid adder for new resources at Antelope. Resources in this level will require the use of an SPS for which a bid adder is assigned. A brief description of these upgrades is provided in Section 5-4 above.

The total estimated capital cost of all of these upgrades is approximately $4.5 million, with an estimated carrying charge of approximately $0.72 million. The bid adder is derived by taking the total estimated project costs for the above upgrades and spreading the costs throughout the total generation in the area (including generation in other areas as well) that would require these facilities. Based on the estimated capital costs of these facilities and the estimated energy production of queued generation projects, the bid adder for projects including the common bid adder discussed above is approximately 0.019 cents per KWH.

Section 6

INYO, MONO AND SAN BERNARDINO COUNTIES SCE CONCEPTUAL TRANSMISSION REQUIREMENTS AND COSTS FOR INTEGRATING WIND AND GEOTHERMAL RESOURCES

6-1. Introduction

SCE revised its previous conceptual transmission studies to incorporate supplemental information received from various renewable resource developers. The supplemental information obtained was in response to SCE's request for additional information from potential renewable energy bidders. This information was used in conjunction with current generation projects (both renewable and non-renewable) requesting interconnection via the CAISO interconnection process and with previously identified renewable resource potential in the CEC's Electric Transmission Plan for Renewable Resources in California Report to the Legislature dated December 1, 2003.

This section presents the revised conceptual transmission plan and corresponding transmission cost estimates necessary to accommodate the renewable resources located in Inyo, Mono and San Bernardino Counties.

6-2. Renewable Resources

The renewable resources identified by the CEC in 2003 included a total of 960 MW of renewable generation by 2017.

Currently, there are a total of twenty three generation interconnection projects totaling 5,221 MW in the CAISO interconnection queue in this area. This includes renewable wind generation projects (60 MW), geothermal projects (100 MW), and (5,061 MW) solar projects (photovoltaic, solar thermal and others).

These interconnection applications reflect significantly more renewable generation development than was forecast by the CEC in 2003. Since renewable generation applications in the CAISO interconnection queue far exceed the renewable resources identified by the CEC, it was assumed that the CEC forecast potential was a subset of the total interconnection queue. Therefore, bid adder analysis was based on queued projects and supplemental information and did not explicitly consider the CEC forecast.

There were twelve projects in the supplemental responses from renewable developers in the area of interest that are not in the CAISO interconnection queue prior to Queue Cluster 3. The total capacity of these projects (4,282 MW) is significant. Because Queue Cluster 3 studies did not include such high amount of MWs, the results contained in the Queue Cluster 3 Phase 1 study would not generally be sufficient to accommodate the incremental additional projects identified in the supplemental responses from renewable developers. As a result, this study provides conceptual upgrades needed to accommodate the supplemental responses.

6-3. Study Assumptions and Study Methodology

Study Assumptions

1. Interconnection Facilities

   The resources identified above were divided into six geographic clusters labeled Clusters 5 through 10. Clusters 5 and 6 consist of generation located in the East of Pisgah area (including the Eldorado/Mohave and Mountain Pass areas) and the Pisgah area, respectively. Clusters 7 and 8 consist of generation located in the Control area and the Inyokern area, respectively. Clusters 9 and 10 consist of generation located in the Kramer/Cool Water area and the Victor area, respectively

   It was assumed that all generation projects would be interconnected to the SCE system by constructing new gen-tie facilities to existing or planned substations, transmission lines, or sub-transmission lines, and the costs of these gen-tie facilities were not derived. The cost for these facilities should be included into the corresponding bids.

2. Network Facilities

   SCE will be upfront financing the costs of reliability and delivery upgrades associated with the Eldorado – Ivanpah Transmission project (EITP) and the South of Kramer Transmission Project (SOK). As such, the costs of these upgrades have not been included in this TRCR analysis.

   Delivery of the energy from the clusters above would require significant upgrades to existing network facilities. Generally speaking, the closer the renewable resource is located to Lugo Substation, the lower the number of upgrades to transmission facilities would be required.

Study Methodology

Modifications to the previous TRCR were extensive in the north of Lugo area due to significant size of the CAISO interconnection queue, which consists primarily but not exclusively of eligible renewable generation projects, as well as response from renewable developers in the area of interest. Bid adders are derived by taking the total project cost for identified transmission system upgrades and spreading the cost for each element or upgraded facility among the projects in the cluster(s) that require those upgrades. The assumptions made with regard to capacity factor are as follows:

- 35 percent for wind generation
- 25 percent for solar generation
- 25 percent for PV generation
- 85 percent for geothermal

Deliveries to SDG&E were assumed at the existing San Onofre 230-kV substation. It should be noted that such deliveries could necessitate an increase in import capability for SDG&E, as well as an increase in transmission capacity to the SDG&E load center. Such increases could be achieved by upgrading south of San Onofre (Path 44) capability or by developing additional SCE-SDG&E system ties. See SDG&E Conceptual studies for further details.

Deliveries to PG&E were assumed at the existing Midway 500-kV substation assuming the existing Path 26 transmission facilities including a new Tehachapi-Midway 500 kV transmission line that can accommodate such increase in imports into PG&E. It should be noted that such deliveries could necessitate an increase in transmission capacity to the PG&E load center. Such increases can be achieved by additional Path 15 reinforcements. See PG&E Conceptual studies for further details.

6-4. Description of Transmission Upgrades

The following are the description of the transmission upgrade facilities necessary to interconnect and deliver generation resources in each of the clusters for San Bernardino and Mono Counties.

East of Pisgah Area

- Expand Eldorado 500/220 kV substation, install new 500/220 kV transformer bank, rated at 1120 MVA, with single phase spare bank.
- Install second Eldorado 500/220 kV transformer bank, rated at 1120 MVA.
- Upgrade existing Lugo to Eldorado Series Cap.
- New 500/220 kV substation and corresponding 29 miles of 220 kV T/L to Ivanpah for additional AA bank capacity, Install new 500/220 kV transformer bank, rated at 1120 MVA, with single phase spare bank.

Pisgah Upgrades

- Expand the existing Pisgah substation to 500 kV, install two new 500/220 kV transformer banks, each rated at 1120 MVA, with single phase spare bank.
- Tear down and rebuild one existing Lugo to Pisgah 220 kV T/L with new 500 kV.
- Expand Lugo 500 kV bus and reconfigure line terminations.

Control area Upgrades

- Upgrade Control area SPS.
- Replace existing Inyokern phase shifter transformer.
- Construct new 115 kV T/L between Control and Inyokern.

Inyokern area Upgrades

- Install new Inyokern area SPS.
- Expand the existing Inyokern substation to 220 kV and install one new 220/115 kV transformer bank.

- Utilize existing 220 kV T/Ls (one currently operated at 115 kV) to provide 220 kV service to Inyokern substation.

Kramer area Upgrades

No upgrades beyond what SCE is currently upfront financing were identified to be required for this area.

Victor area Upgrades

Projects that request interconnection to non-CAISO controlled (radial 115-kV or lower) facilities in the area may require subtransmission or distribution system upgrades that are typically the cost responsibility of the developer and not subject to refund. These costs can vary greatly depending on the specific location, size of the project, and subtransmission or distribution system infrastructure in that area. Furthermore, these upgrades are typically very specific to individual generation projects, do not accommodate large numbers of projects (i.e., the upgrades are typically not common to all projects in any given cluster), and may require significant capital investment to construct. The bid adders in this report are not able to reflect the estimated costs of non-network subtransmission or distribution system upgrades. These costs need to be addressed on a project-by-project basis for any project requesting interconnection at 115-kV or lower voltages, and such costs should be reflected by each developer into the corresponding bids. Consequently, no upgrades were identified to be required for this area.

6-5. Transmission Project Cost Estimates for Bid Evaluation

Facilities for Cluster 5 (East of Pisgah)

Cluster 5 Level 1: Up to 400 MW

Level 1 represents the available capacity on the existing system with inclusion of EITP upgrades currently upfront financed by SCE as discussed above.

Bids associated with active interconnection serial projects defined to be part of the East of Pisgah area should be assigned a zero bid adder due to SCE commitment to upfront finance EITP. All other projects in the area should be given a bid adder based on Cluster 5 Level 2 or Level 3 below. For additional details related to EITP, see the FERC decision which can be found at http://www.caiso.com/1bee/1bee799b1f1f0.doc.

Cluster 5 Level 2: 401 MW to 1,050 MW

Level 2 represents the available capacity after the inclusion of upgrades required to accommodate Transition Cluster projects currently in the CAISO interconnection queue.

The total estimated capital cost of all of these upgrades is approximately $115 million, with an estimated carrying charge of approximately $18.40 million. The bid adder is derived by taking the total estimated project costs for the above upgrades and spreading

the costs throughout the total generation in the area (including generation in other areas as necessary) beyond 400 MW and up to 1,050 MW that would require these facilities. Based on the estimated capital costs of these facilities and the estimated energy production of queued generation projects, the bid adder for projects in this level is approximately 0.799 cents per KWH.

Cluster 5 Level 3: 1,051 MW to 2,000 MW

Level 3 represents the available capacity after the inclusion of additional upgrades required to accommodate Queue Cluster 3 & 4 projects currently in the CAISO interconnection queue.

The total estimated capital cost of all of these upgrades is approximately $90 million, with an estimated carrying charge of approximately $14.4 million. The bid adder is derived by taking the total estimated project costs for the above upgrades and spreading the costs throughout the total generation in the area (including generation in other areas as necessary) beyond 1,050 MW and up to 2,000 MW that would require these facilities. Based on the estimated capital costs of these facilities and the estimated energy production of queued generation projects, the bid adder for projects in this level is approximately 0.691 cents per KWH.

Cluster 5 Level 4: Beyond 2,000 MW

Level 4 represents the available capacity after the inclusion of additional upgrades required to accommodate resources beyond 2,000 MW.

The total estimated capital cost of all of these upgrades is approximately $168 million, with an estimated carrying charge of approximately $26.88 million. The bid adder is derived by taking the total estimated project costs for the above upgrades and spreading the costs throughout the total generation in the area (including generation in other areas as necessary) beyond 2,000 MW that would require these facilities. Based on the estimated capital costs of these facilities and the estimated energy production of queued generation projects, the bid adder for projects in this level is approximately 1.542 cents per KWH.

<u>Facilities for Cluster 6 (Pisgah)</u>

Cluster 6 Level 1: Up to 275 MW

Level 1 represents the available capacity on the existing system without any upgrades.

Cluster 6 Level 2: 276 MW to 2,000 MW

Level 2 represents the available capacity after the inclusion of upgrades to accommodate all serial projects currently in the CAISO interconnection queue. While SCE has requested and received FERC approval to upfront finance upgrades associated with Level

2, such upfront financing is predicated on meeting specific milestones within an executed LGIA. Currently, the executed LGIA is suspended adversely impacting meeting the specified milestones. Consequently, this TRCR assumes that the milestones will not be met and consequently provides for a bid adder to be included.

The estimated capital cost of all these upgrades is $753 million, with an estimated annual carrying charge of $120.5 million. The bid adder is derived by taking the total estimated project costs for the above upgrades and spreading the cost throughout the total generation in the area that would require these facilities (including generation in other clusters that also require these facilities). Based on the estimated capital costs of these facilities and the estimated energy production of queued generation projects, the bid adder for this cluster is approximately 2.249 cents per KWH.

Facilities for Cluster 7 (Control Area)

Cluster 7 Level 1: 0 MW

Level 1 represents the available capacity on the existing system without any upgrades

Cluster 7 Level 2: Up to 62 MW

Level 2 represents the available capacity after the inclusion of upgrades to accommodate serial projects currently in the CAISO interconnection queue.

The estimated capital cost of these upgrades is $91 million, with an estimated annual carrying charge of $14.5 million. The bid adder is derived by taking the total estimated project costs for the above upgrades and spreading the cost throughout the total generation in the area that would require these facilities (including generation in other clusters that also require these facilities). Based on the estimated capital costs of these facilities and the estimated energy production of queued generation projects, the bid adder for this cluster is approximately 2.822 cents per KWH.

Cluster 7 Level 3: 63 MW to 110 MW

Level 3 represents the available capacity after the inclusion of upgrades to accommodate projects currently in the CAISO interconnection queue behind the serial requests through Queue Cluster 2.

The estimated capital cost of these upgrades is $195 million, with an estimated annual carrying charge of $31.2 million. The bid adder is derived by taking the total estimated project costs for the above upgrades and spreading the cost throughout the total generation in the area that would require these facilities (including generation in other clusters that also require these facilities). Based on the estimated capital costs of these facilities and the estimated energy production of queued generation projects, the bid adder for this cluster is approximately 2.075 cents per KWH.

Cluster 7 Level 4: Beyond 110 MW (upper limit not defined)

The Level 4 bid adder will consist of the bid adder defined in level 3 plus the bid adder defined for Cluster 8 level 3 for a total bid adder of 2.362 cents per KWH.

Facilities for Cluster 8 (Inyokern Area)

Cluster 8 Level 1: 0 MW

Level 1 represents the available capacity on the existing system without any upgrades

Cluster 8 Level 2: Up to 40 MW

Level 2 represents the available capacity after the inclusion of SPS identified to be required for this area.

The estimated capital cost of these upgrades is $1.5 million, with an estimated annual carrying charge of $0.24 million. The bid adder is derived by taking the total estimated project costs for the above upgrades and spreading the cost throughout the total generation in the area that would require these facilities (including generation in other clusters that also require these facilities). Based on the estimated capital costs of these facilities and the estimated energy production of queued generation projects, the bid adder for this cluster is approximately 0.027 cents per KWH.

Cluster 8 Level 3: Beyond 40 MW (sharing with Cluster 7 Level 4)

Level 2 represents the available capacity after the inclusion of conceptual upgrades identified to be required for this area.

The estimated capital cost of these upgrades is $27 million, with an estimated annual carrying charge of $4.3 million. The bid adder is derived by taking the total estimated project costs for the above upgrades and spreading the cost throughout the total generation in the area that would require these facilities (including generation in other clusters that also require these facilities). Based on the estimated capital costs of these facilities and the estimated energy production of queued generation projects, the bid adder for this cluster is approximately 0.287 cents per KWH.

Facilities for Cluster 9 (Kramer Area)

Cluster 8 Level 1: Up to 1,000 MW

Level 1 represents the available capacity on the existing system with the inclusion of SOK Upgrades currently upfront financed by SCE as discussed above.

Facilities for Cluster 10 (Victor Area)

Cluster 10 Level 1:

While subtransmission upgrades may be necessary to support projects in queue as well as MWs in response to SCE request for information, these upgrades are not identified in this TRCR for reasons discussed in Section 7-4 above. Consequently, no upgrades were defined for Cluster 10.

Section 7

IMPERIAL AND RIVERSIDE COUNTIES SCE CONCEPTUAL TRANSMISSION REQUIREMENTS AND COSTS FOR INTEGRATING WIND AND GEOTHERMAL RESOURCES

7-1. Introduction

SCE revised its previous conceptual transmission studies to incorporate supplemental information received from various renewable resource developers and to incorporate the latest Tehachapi Transmission Plan formulated as part of the California ISO South Regional Transmission Plan (CSRTP). The supplemental information obtained was in response to SCE's request for additional information from potential renewable energy bidders. This information was used in conjunction with current generation projects (both renewable and non-renewable) requesting interconnection via the CAISO interconnection process and with previously identified renewable resource potential in the CEC's Electric Transmission Plan for Renewable Resources in California Report to the Legislature dated December 1, 2003.

This Section presents the revised conceptual transmission plan and corresponding transmission cost estimates necessary to accommodate the renewable resources located in Imperial and Riverside Counties.

7-2. Renewable Resources

The renewable resources identified by the CEC in 2003 included a total of 960 MW of renewable generation by 2017.

There are a total of twenty generation interconnection projects totaling 7,046 MW in the CAISO interconnection queue in this area through Cluster 4. This includes renewable wind generation projects (267 MW) and solar projects both solar thermal and photovoltaic (5,359 MW). These interconnection applications reflect significantly more renewable generation development than was forecast by the CEC in 2003. Since renewable generation applications in the CAISO interconnection queue far exceed the renewable resources identified by the CEC, it was assumed that the CEC forecast potential was a subset of the total interconnection queue. Therefore, bid adder analysis was based on queued projects and supplemental information and did not explicitly consider the CEC forecast.

There was five projects in the supplemental responses from renewable developers in the area of interest that are not in the CAISO interconnection queue prior to Cluster 4 (four of the requests are part of the Cluster 5). The total capacity of these projects (700 MW) is significantly less than the overall capacity of active generation interconnection requests through Cluster 4 (7,046 MW). It was assumed that upgrades identified in the Cluster 3 Phase 1 study would generally be sufficient to accommodate the incremental additional projects identified in the supplemental responses from renewable developers

7-3. Study Assumptions and Study Methodology

Study Assumptions

1. Interconnection Facilities

   The resources identified above were divided into four geographic clusters labeled Clusters 11 through 14. Cluster 11 consists of renewable generation projects near the California-Arizona border near Colorado River Substation. Cluster 12 consists of renewable projects in the Red Bluff area west of Colorado River and east of Devers. Clusters 13 consist of renewable generation in the Devers 115 kV Subtransmission. Cluster 14 consists of renewable generation in Imperial County.

   It was assumed that all generation projects would be interconnected to the SCE system by constructing new gen-tie facilities to existing or planned substations, transmission lines, or sub-transmission lines, and the costs of these gen-tie facilities were not derived. The cost for these facilities should be included into the corresponding bids.

2. Network Facilities

   SCE will be upfront financing the costs of reliability and delivery upgrades associated with Devers – Colorado River Transmission Project (DCR), West Of Devers Transmission Project (WOD) and the Colorado River Expansion. As such, the costs of these upgrades have not been included in this TRCR analysis.

   Delivery of the energy from the clusters above would require significant upgrades to existing network facilities. Generally speaking, the closer the renewable resource is located to the Devers substation, the lower the number of upgrades to transmission facilities would be required.

Study Methodology

Modifications to the previous TRCR were made due to the significant amount of generation projects that have requested interconnection since last year and the recently completed Cluster 3 Phase 1 interconnection study. Bid adders are derived by taking the total project cost for identified transmission system upgrades and spreading the cost for each element or upgraded facility among the projects in the cluster(s) that require those upgrades. The assumptions made with regard to capacity factor are as follows:

- 30 percent for wind generation
- 25 percent for solar generation
- 25 percent for PV generation
- 50 percent for non-renewable
- 95 percent for geothermal

Deliveries to SDG&E were assumed at the existing San Onofre 230-kV substation. It should be noted that such deliveries could necessitate an increase in import capability for SDG&E, as well as an increase in transmission capacity to the SDG&E load center. Such increases could be achieved by upgrading south of San Onofre (Path 44) capability or by developing additional SCE-SDG&E system ties. See SDG&E Conceptual studies for further details.

Deliveries to PG&E were assumed at the existing Midway 500-kV substation assuming the existing Path 26 transmission facilities including a new Tehachapi-Midway 500 kV transmission line that can accommodate such increase in imports into PG&E. It should be noted that such deliveries could necessitate an increase in transmission capacity to the PG&E load center. Such increases can be achieved by additional Path 15 reinforcements. See PG&E Conceptual studies for further details.

7-4. Description of Transmission Upgrades

The following are the high level description of the transmission upgrade facilities necessary to interconnect and deliver generation resources in each of the clusters for Imperial and Riverside Counties.

Colorado River Substation Area

- Install two additional 500/220 kV transformer banks, each rated at 1120 MVA, with single phase spare bank.
- Install 500 MVAR Static VAR Compensator (SVC) at the Colorado River Substation (CRS) 220 kV bus.
- Implement SPS to mitigate overload under contingency.

Red Bluff Substation Area

- Install one additional 500 / 220 kV transformer bank at the Red Bluff 500 kV Substation.

Devers - Mirage 115-kV Area

Projects that request interconnection to 115 kV facilities that are currently under CAISO control may require subtransmission system upgrades. These 115 kV facilities will be converted to non-CAISO facilities upon completion of SCE's Devers Mirage split project. Costs associated with upgrades to non-CAISO controlled facilities are typically the cost responsibility of the developer and not subject to refund. These costs can vary greatly depending on the specific location, size of the project, and subtransmission or distribution system infrastructure in that area. Furthermore, these upgrades are typically very specific to individual generation projects and do not accommodate large numbers of projects (i.e., the upgrades are typically not common to all projects in any given cluster). As such, this TRCR did not identify any subtransmission upgrades and

did not include a corresponding subtransmission bid adder for this area. Consequently, the costs for subtransmission upgrades need to be addressed on a project-by-project basis and should be reflected by each developer into the corresponding energy bid, if applicable.

Path 42

The IID 230-kV system is currently connected to SCE's Devers and Mirage 230-kV substations with the Coachella-Devers and Coachella-Mirage 230-kV lines (Path 42). This path is currently used to import power from existing Qualifying Facilities (geothermal resources) located in Imperial County and is rated at 600 MW. To increase Path 42 capability, physical upgrades are necessary. SCE is currently undertaking upgrades on the SCE portion of Path 42. These upgrades involve reconductoring line segments between Devers and Mirage (Path 42 will be reconfigured to terminate at Mirage Substation), and implementing line outage detection to be used for SPS. Additional upgrades internal to IID, including the IID portion of Path 42, are also necessary to increase Path 42 rating. This TRCR does not identify any upgrades necessary for Path 42 rating increase. Consequently, the costs for such Path 42 upgrades should be reflected by each developer seeking interconnection within IID into the corresponding energy bid, if applicable.

7-5. Transmission Project Cost Estimates for Bid Evaluation

Facilities for all Clusters below

Some projects located in the Eastern Area discussed below will need to share the cost of the SVC required for supporting 500 kV system voltage performance. Specifically, the projects identified under Level 2 in the clusters discussed below.

The total estimated capital cost of the SVC upgrade is approximately $100.0 million, with an estimated carrying charge of approximately $16 million. The bid adder is derived by taking the total estimated project costs for the above upgrades and spreading the costs throughout the specific generation in the area that would require these facilities. Based on the estimated capital costs of these facilities and the estimated energy production of queued generation projects, the bid adder for this upgrade is approximately 0.265 cents per KWH. This bid adder will be included in the bid adder for each cluster below as appropriate.

Facilities for Cluster 11 (Colorado River)

Cluster 11 Level 1: Up to 2,000 MW

Level 1 represents the available capacity on the system with the inclusion CRS upgrades currently upfront financed by SCE as discussed above.

Bids associated with active interconnection projects through Queue Cluster 2 defined to be part of the Colorado River should be assigned a zero bid adder due to SCE's commitment to upfront finance the DCR, WOD and Colorado River Expansion. (SCE's upfront financing of upgrades in support of Transition Cluster projects provides sufficient capacity at CRS through Queue Cluster 2). All other projects in the area should be given a bid adder based on Cluster 11 Level 2 below. For additional details related to the TC, see the FERC decision which can be found at http://www.caiso.com/1bee/1bee799b1f1f0.doc.

Cluster 11 Level 2: 2,000 MW up to 4,000 MW

Level 2 represents the available capacity after the inclusion of upgrades necessary to support projects beyond Queue Cluster 2. Resources in this level will require an additional two 500/220 kV transformer banks, and the use of an SPS for which a bid adder is assigned. A brief description of these upgrades is provided in Section 7-4 above.

The total estimated capital cost of all of these upgrades is approximately $180 million, with an estimated carrying charge of approximately $28.80 million. The bid adder is derived by taking the total estimated project costs for the above upgrades and spreading the costs throughout the total generation in the area (including generation in other areas as necessary) that would require these facilities and adding the shared bid adder derived above. Based on the estimated capital costs of these facilities and the estimated energy production of queued generation projects, the bid adder for projects in this level including the bid adder with the SVC is approximately 0.873 cents per KWH.

Cluster 11 Level 3: Beyond 4,000 MW

Level 3 will require the installation of a new 500/220 kV Substation in the area. This TRCR does not provide a bid adder for such new facilities based on the assumption that the amount of new resources to ultimately develop in the Colorado River Area will be below the 4,000 MW threshold. However, detailed studies to be performed as part of the generation interconnection process may determine that an additional substation is required. As such, all bids in this area will be limited to the bid adder provided for Level 2.

<u>Facilities for Cluster 12 (Red Bluff)</u>

Cluster 12 Level 1: Up to 1,050 MW

Level 1 represents the available capacity on the system with the inclusion of Red Bluff upgrades currently upfront financed by SCE as discussed above.

Bids associated with active interconnection projects through the Transition Cluster defined to be part of Red Bluff should be assigned a zero bid adder due to SCE's commitment to upfront finance the DCR, WOD, Red Bluff, and Colorado River Expansion. All other projects in the area should be given a bid adder based on Cluster 12

Level 2 below. For additional details related to the TC, see the FERC decision which can be found at http://www.caiso.com/1bee/1bee799b1f1f0.doc.

Cluster 12 Level 2: 1,050 MW up to 2,100 MW

Level 2 represents the available capacity after the inclusion of upgrades necessary to support projects beyond the Transition Cluster. Resources in this level will require one additional 500/220 kV transformer bank for which a bid adder is assigned. A brief description of these upgrades is provided in Section 7-4 above.

The total estimated capital cost of all of these upgrades is approximately $90 million, with an estimated carrying charge of approximately $14.40 million. The bid adder is derived by taking the total estimated project costs for the above upgrades and spreading the costs throughout the total generation in the area (including generation in other areas as necessary) that would require these facilities and adding the shared bid adder derived above. Based on the estimated capital costs of these facilities and the estimated energy production of queued generation projects, the bid adder for projects in this level including the bid adder with the SVC is approximately 1.141 cents per KWH.

<u>Facilities for Cluster 13 (West of Devers)</u>

Cluster 13 Level 1:

While subtransmission upgrades may be necessary to support projects in queue as well as MWs in response to SCE's request for information, these upgrades are not identified in this TRCR for reasons discussed in Section 7-4 above. Consequently, no upgrades were defined for Cluster 13.

<u>Facilities for Cluster 14 (IID via Path 42)</u>

Cluster 14 Level 1:

While upgrades may be necessary to support projects internal to IID as well as MWs in response to SCE's request for information, these upgrades are not identified in this TRCR for reasons discussed in Section 7-4 above. Consequently, no upgrades were defined for Cluster 14.