SCE CONCEPTUAL TRANSMISSION REQUIREMENTS AND COSTS FOR INTEGRATING RENEWABLE RESOURCES

September 29, 2008

Southern California Edison Company

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1. Executive Summary

On June 20, 2008, the Assigned Commissioner to Rulemaking (R.) 06-05-027 issued a ruling requiring, among other things, Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas and Electric Company (SDG&E) to prepare and file a Transmission Ranking Cost Report (TRCR). The original schedule called for filing of 2009 draft TRCR by September 15, 2008. On August 12, 2008, the schedule for filing the draft TRCR was extended to October 1, 2008 by Administrative Law Judge (ALJ) ruling.

SCE has developed the TRCR describing the renewable conceptual transmission upgrades and their associated costs based on the updated supplemental solicitation 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 report 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 report 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 report.

The approach utilized in this TRCR is consistent with that outlined in Attachment A of the California Public Utilities Commission (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 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. In addition, Section 8 addresses issues related to identified renewable resources identified in the supplemental information received by SCE but geographically located outside of SCE service territory.

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	Comment	Level 1	Level 2	Comment
1	Los Angeles and Kern Counties (Whirlwind, Windhub/Highwind, and other areas)	15,096	40,285	$ -	$1,300	$3,400	0	0.52	1.35
			MW Total	0	15,098	(w/ATP & TRTP)			(w/ATP & TRTP)
2	Pisgah Area	9,736	22,836	$ -	$3,570	-	0	1.05	-
			MW Total	0	9,736				
3	El Dorado/ Mohave Area	7,234	18,808	$ -	$3,570	-	0	0.95	-
			MW Total	0	7,234				
4	Mountain Pass Area	1,927	4,275	$ -	$3,710	-	0	1.66	-
			MW Total	0	1,927				
5	Desert View/Lugo Area	1,370	3,412	$ -	$2,700	-	0	0.70	-
			MW Total	0	1,370				
6	Coolwater Area	2,014	5,283	$ -	$2,150	-	0	0.90	-
			MW Total	0	2,014				
7	Victor Area	1,406	4,450	$ -	$2,130	-	0	0.80	-
			MW Total	0	1,406				
8	Kramer Area	1,710	3,929	$ -	$2,100	-	0	0.96	-
			MW Total	0	1,710				
9	Inyokern Area	1,505	3,598	$ -	$2,250	-	0	1.64	-
			MW Total	0	1,505				
10	Control Area	572	4,546	$ -	$2,590	-	0	1.87	-
			MW Total	0	572				
11	Midpoint Area	6,870	15,987	$ -	$1,670	$2,070	0	1.13	1.48
			MW Total	0	15,987	(w/DPV2)			(w/DPV2)
12	Eagle Mountain/Julian Hinds Area	3,778	9,612	$ -	$1,360	$1,460	0	0.82	0.86
			MW Total	0	9,612	(w/DPV2)			(w/DPV2)
13	Devers Area	3,997	10,392	$ -	$490	$590	0	0.64	0.77
			MW Total	0	10,392	(w/DPV2)			(w/DPV2)
14	IID Area (Path 42)	450	3,745	$ -	$570	$670	0	0.46	0.47
			MW Total	0	3,745	(w/DPV2)			(w/DPV2)
TOTAL		**57,665**	**151,159**						

Note 1: For areas outside of SCIT, even with the upgrades identified, these areas may be subject to curtailment of renewables due to SCIT Southern California inertia limits

Note 2: Does not include sub-transmission/distribution upgrade requirements for projects requesting interconnection to (non-CAISO) radial systems

2. Background

In September 2002, Governor Davis signed Senate Bill (SB) 1038 and SB 1078 creating the California Renewables Portfolio Standard (RPS) program.[1] Under these laws, retail sellers (i.e., electrical corporations, community choice aggregators, electric service providers) are required to increase their total procurement of electricity from eligible renewable resources each year by 1% of total retail sales and reach a goal of 20% renewables by 2010. Cost recovery of the transmission facility upgrades is assured through general transmission rates.[2]

State Senate Bills 1038 and 1078

Pursuant to the requirements of SB 1038 and SB 1078, the California Energy Commission (CEC) developed the "Preliminary Renewable Resource Assessment" Report. The first version of this assessment was created on July 1, 2003. Subsequently, the CEC developed the final version of the report entitled "Renewable Resources Development Report" (Document 500-03-080F) on November 19, 2003. This report was adopted for submittal to the State Legislature. The Report is a comprehensive renewable resources development plan that describes the renewable resources in California, and estimated costs of the electricity generation from these resources.

SB 1038 also includes an important provision requiring the CPUC to prepare, by December 1, 2003, a comprehensive transmission plan for connecting the CEC estimated renewable electricity generation facilities, and to provide for the rational, orderly, cost effective expansion of transmission necessary to facilitate development of renewable generation.

In order to fulfill this requirement, Administrative Law Judge (ALJ) Gottstein of the CPUC requested that the utilities move forward without delay to develop cost estimates for renewable resource transmission projects, and report their progress in the transmission monthly status reports provided as part of the AB 970 proceedings (Investigation (I.) 00-11-001).

Completed SCE Conceptual Transmission Studies for Renewable Resource Developers

During 2002 and 2003, SCE completed conceptual transmission studies in support of I.00-11-00 into transmission constraints facing the State in accommodating the new wind generation resources in the Antelope Valley and Tehachapi areas of Kern and Los Angeles counties.

The first two conceptual studies were conducted exclusively for integrating wind generation in the Tehachapi area with a combined output of 2,500 MW. These Tehachapi Transmission Conceptual Facilities Reports, which incorporated the results of these two

[1] Recently Governor Schwarzenegger signed into law SB 107, which further amends the RPS legislation.
[2] *See* Pub. Util. Code Section 454.1.

studies, were published on March 14, 2002 and January 15, 2003 and were provided to participants per agreement. Subsequent conceptual studies were proposed by developers in response to a general solicitation letter to industry participants provided by SCE to renewable resource developers on February 13, 2003, at the request of ALJ Gottstein. The purpose of the letter was to invite their participation in a conceptual transmission study to determine the feasibility, scope, and costs of potential transmission facilities required to connect the new renewable energy projects throughout SCE's service territory.

This invitation resulted into three participants signing agreements with SCE during April 2003 for conceptual studies for their renewable wind and geothermal resources located in SCE's service territory. In the Mono County area, two geothermal developers, Vulcan Power Company and Geo Energy Partners, signed agreements for SCE to complete the conceptual transmission facilities studies for a total of 155 MW of geothermal power. In the Imperial County area, Geo Energy Partners also signed an agreement for SCE to complete the conceptual transmission facilities studies for a total of 40 MW of geothermal power. Lastly, in the Tehachapi area, enXco signed an agreement to complete the conceptual transmission facilities studies for an increase of Tehachapi area wind generation total from 2,500 MW to 3,270 MW. SCE completed these studies and published the results on June 27, 2003. SCE presented the results of all three Conceptual Transmission Facilities Studies to participants and representatives of CPUC, CAISO, CEC and PG&E in a meeting in Ontario, California on May 30, 2003 and also provided copies of the reports and presentations to each attendee.

SCE Renewable Conceptual Transmission Plan

SCE developed its first version of its Renewable Conceptual Transmission Plan (RCTP) in accordance with the "Scope of Work" as described in Attachment A to ALJ Meg Gottstein's ruling on March 27, 2003. The ruling was further modified and clarified in subsequent rulings issued by ALJ Charlotte F. TerKeurst on July 21, 2003 and August 1, 2003. The RCTP was based on the first CEC Report with renewable MW tabulated in Table 5 of the report, which was submitted to CPUC and renewable stakeholders on August 29, 2003. Table 5 of the report describes all SCE conceptual transmission upgrades and their estimated costs that are needed to connect all renewables in the SCE and Imperial Irrigation District (IID) territories, which had a total of 470 MW of renewable resources in 2005, a cumulative total of 1755 MW of renewable resources by 2008, a cumulative total of 4,220 MW of renewable resources by 2017, and a total of 6,270 MW of renewable resources under the remaining potential.

CPUC Electric Transmission Plan for Renewable Resources in California

The CPUC Energy Division developed the "Electric Transmission Plan for Renewable Resources in California Report" based on the Utilities' Filings of the RCTP and subsequent tabulated data revisions of their plans for the revised renewable assessment in the CEC November 2003 Report. Pursuant to the directives under SB 1038 and SB 1072, the CPUC Energy Division submitted the report describing renewable conceptual

transmission upgrades and their estimated costs to the California Legislature on December 1, 2003.

Tehachapi Collaborative Study Group Final Reports

On March 16, SCE filed a final report for the first Tehachapi Collaborative Study Group (TCSG) on behalf of the TCSG. The final report identified four possible transmission plans for integrating over 4,000 MW of wind generation from the Tehachapi region. The four potential transmission plans were all identified to have virtually identical cost estimates. As a result, additional study work was undertaken as part of a second TCSG with a goal of identifying the most prudent alternative. The final report of this additional study work was filed by SCE on April 19, 2006 on behalf of the TCSG. The TCSG reached consensus on the first three phases of the Tehachapi expansion, which were estimated to provide capacity for up to 3,000 MW of wind generation. However, concurrence was not reached on the final phase to support the full wind generation potential.

California ISO South Regional Transmission Plan (CSRTP)

Since concurrence of the final phase to support wind generation levels in excess of the capability of the first three phases was not reached, the TCSG recommended that the CAISO complete the evaluation needed to select the final plan of service for Tehachapi. As a result, the CAISO formed the CSRTP team which included the CAISO, participating transmission owners (PG&E, SCE, and SDG&E), technical representatives from all generation project sponsors (Nevada Hydro Company, Citizens Energy, IID, Oak Creek Energy System/Tehachapi Holdings), and technical representatives from the CEC and the California Electricity Oversight Board (EOB). A final plan of service for Tehachapi has been developed and approved by the CAISO Governing Board on January 24, 2006.

Imperial Valley Collaborative Study Group Final Report

Another Collaborative Study Group developed a conceptual transmission plan for integrating geothermal renewable resources in the Imperial Valley. Transmission facilities necessary to integrate over 2,000 MW of geothermal potential include new transmission into San Diego, new transmission into SCE, and new transmission within the IID. This report only captures SCE's transmission related costs.

Request for Supplemental Information from Eligible Renewable Developers

On June 20, 2008, the Assigned Commissioner to R.06-05-027 issued a ruling requiring SCE, PG&E and SDG&E to request additional information from developers of eligible renewable energy projects who may participate in the State RPS program. The purpose of the supplemental information was to assist in developing necessary transmission plans to properly integrate eligible renewable energy projects. In this request for supplemental information, SCE required parties to file a response even though no changes were made

to last year's information. This was done to ensure that projects identified by developers during previous request for additional information, which may no longer be viable, are not mistakenly included into this assessment.

This report includes the supplemental information obtained in response to SCE's supplemental information request. A summary of responses from renewable developers to this supplemental solicitation is described in Section 3 of this report.

CAISO Generator Interconnection Process Reform (GIPR)

The foundation for the current generation interconnection process was established by FERC in Order No. 2003 and its progeny. The Large Generator Interconnection Procedures (LGIP) tariff has successfully assured the open transmission access requirement for new generation interconnection customers. However, over the past few years, several factors, largely unanticipated at the time of Order 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. For example, as of July 27, 2008, there were 361 active interconnection requests in the CAISO interconnection queue totaling over 105,000 MW (over 68,000 MW renewable alone).

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 current LGIP to allow 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 renewable portfolio standard requirements. On July 28, 2008 the CAISO filed with FERC an amendment to the currently effective CAISO Tariff. In this 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.

It is important to note that the significant amount of queued renewable generation in the CAISO interconnection queue far exceeds the amount of renewable generation that would be required to meet state mandated RPS targets, although per FERC interconnection protocols these projects in queue must be treated on an equal basis. It is highly anticipated that as the CAISO GIPR process continues and the first GIPR cluster studies commence, there will be a significant number of projects that drop out of the current CAISO interconnection queue. Therefore, this Transmission Ranking Cost Report and the bid adders calculated here are based on the best information available today, but that information is subject to change. It is highly anticipated that future TRCR analysis will yield different results based on the highly dynamic nature of CAISO interconnection process reform efforts that are currently underway.

The GIPR proposal, stakeholder comments on the GIPR proposal, and links to relevant FERC filings can be found at www.caiso.com/1f42/1f42c00d28c30.html.

3. Response to Request for Supplemental Information

Pursuant to the June 20, 2008 Assigned Commissioner Ruling in R.06-05-027, SCE sent out a solicitation letter on August 6, 2008 to renewable energy developers requesting them to provide additional information regarding transmission. The deadline for interested parties to respond to this supplemental solicitation was August 20, 2008. Based on the revisions to previous conceptual transmission plans to accommodate new interconnection requests of renewable resources made since the last TRCR and additional information obtained in response to SCE's request for supplemental information, SCE has developed this TRCR.

Fifteen developers responded to SCE's supplemental information request. These developers identified up to fourty-eight potential renewable resource projects including twenty-nine in SCE's service territory for a total of 15,424 MW. These fourth-eight projects include five geothermal projects (226 MW), one combined biomass/concentrated solar project (1000 MW), twenty-nine solar projects (9,155 MW), one PV project (400 MW), and five wind projects (4,643 MW). The non-SCE service territory projects included two projects in IID (150 MW), three projects in SDGE (1,030 MW), four projects in Arizona (3,000 MW), one project in northern California (23 MW), one project in Utah (18 MW) and one project in Texas (4,000 MW). The majority of projects identified in the request for supplemental information were in fact already active projects in the CAISO interconnection queue.

There were several developers that provided incomplete or insufficient information in this request for supplemental information; these projects were not considered in the bid adder analysis presented in this report.

There is 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. The majority of projects in the CAISO interconnection queue are renewable, and these projects far exceed the MW totals identified in the supplemental request for information. Therefore, the facilities for interconnection of queued generation were the significant factor in determining bid adders for renewable generation. In general, the transmission facilities that drive those bid adders would also create sufficient capacity to accommodate those few remaining generation projects that were identified in the supplemental request for information while at the same time not reflected in the CAISO interconnection queue. As a result, there were generally no bid adder adjustments made due to provided supplemental information.

This TRCR will include interconnection requests in identifying potential transmission upgrade requirements. However, unless actual interconnection studies have been conducted, the conceptual transmission facilities are an approximation of what will ultimately be required and will be finalized when such studies are conducted.

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 and revised phasing needed to accommodate the interconnection and delivery of generated power from all renewable resource projects received in response to SCE's solicitation as well as the renewable resources currently progressing through the Federal Energy Regulatory Commission (FERC) mandated generation interconnection process.

The most significant limitation of this TRCR is associated with the sheer size of the existing CAISO interconnection queue. As shown in Table 1-1, there is currently in excess of 57,000 MW of generation (over 52,000 MW of which is renewable in nature) requesting interconnection into the SCE system through the FERC interconnection process. To put this number into perspective, this generation capacity "proposed" by developers in queue is more than double the total customer demand served throughout the entire SCE service territory, and is nearly identical to the entire customer demand served throughout the entire CAISO system. It is impossible to envision a comprehensive set of transmission upgrades that can accommodate all of these renewable projects currently in the interconnection queue. As a result, this SCE 2009 TRCR involves a number of assumptions, simplifications, and estimations in the absence of detailed studies.

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 be considered in relative comparison to other transmission bid adders 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 system impact studies for each renewable project need to be performed to identify the actual impacts of the project on the existing electric system and facilities required to interconnect the project(s).

4. Detailed facilities studies for each renewable project need to be performed to properly engineer, design, and estimate actual costs of the facility upgrades required.

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

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

7. 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.

8. 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.

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

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

11. Renewable integration and operational issues were not considered.

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 reveal that 285 MW and 100 MW were forecasted in 2005 for Kern and Los Angeles County respectively. An additional 1,410 MW are forecasted by 2008 for Kern County, and an additional 2,365 MW and 315 MW are forecasted by 2017 for Kern and Los Angeles County respectively. These totals are shown below in Table 5-1.

Table 5-1
Renewable Resources Identified by the CEC
CEC's Electric Transmission Plan for Renewable Resources in California
Report to the Legislature dated December 1, 2003

Data Source	Location of Wind Resource	Year			Total
		2005	2008	2017	
CEC Report	Kern County	285	1,410	2,365	4,060
	Los Angeles County	100	0	315	415
	Annual Total	385	1,410	2,680	
	Running Total	385	1,795	4,475	

Currently, there are a total of sixty-two generation interconnection projects totaling 14,696 MW in the CAISO interconnection queue in this area. This includes renewable wind generation projects (5,852 MW), solar projects (3,310 MW), combined wind/solar projects (1,150 MW), solar photovoltaic projects (4,055 MW) and non-renewable gas-fired projects (729 MW). All of these projects in the CAISO interconnection queue require transmission upgrades in this area. 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.

In addition to the queued projects, there was one project identified in the supplemental responses from renewable developers that was in the area of interest but was not currently reflected in the CAISO interconnection queue. This project (400 MW) was considered in addition to the projects currently in the CAISO interconnection queue for development of the conceptual transmission plan for this area. The projects currently in the CAISO queue and the supplemental information obtained are shown in Table 5-2 and Table 5-3. Note that the information in these tables is based on requested in-service dates for projects in the CAISO interconnection queue and may not reflect the latest in-service dates for all projects.

Table 5-2
Supplemental Response from Renewable Resource Developers and
CAISO Interconnection Queue
Based on Location

Location	2008	2009	2010	2011	2012	2013	2014	2015	2016
Whirlwind			737	2029	970	640	70	40	40
Windhub/Highwind		1132	974	1805	330	2445	255	144	175
Other	166	249	175	1480	570	670	0	0	0
Annual Total	166	1381	1886	5314	1870	3755	325	184	215
Running Total	166	1547	3433	8747	10617	14372	14697	14881	15096

Table 5-3
Supplemental Response from Renewable Resource Developers and
CAISO Interconnection Queue
Based on Technology

Technology	2008	2009	2010	2011	2012	2013	2014	2015	2016
PV	7	583	175	1590	900	800			
Solar		330	495	2235		250			
Wind		468	1216	1489	400	1555	325	184	215
Wind/Solar						1150			
Other	159				570				
Annual Total	166	1381	1886	5314	1870	3755	325	184	215
Running Total	166	1547	3433	8747	10617	14372	14697	14881	15096

5-3. Study Assumptions and Study Methodology

Study Assumptions

1. Interconnection Facilities

   All the resources identified above are divided into three general areas: 1) resources near Rosamond Avenue and 170th Street West (Whirlwind Substation area), 2) resources in Tehachapi (Windhub and Highwind Substation areas), and 3) resources elsewhere in the Big Creek Corridor. All of these resources impact flows south of Antelope. Since projects proceeding through the CAISO Interconnection process have interconnection priority, the transmission bid adders where developed by assessing the conceptual transmission facilities necessary to integrate these projects first.

   It was assumed that all wind generation projects would be interconnected to the SCE system by constructing new gen-tie facilities to one of the three new substations proposed (Windhub, Whirlwind, or Highwind) for which costs were not derived. These new gen-tie facilities would include a new 230 kV transmission line(s) and a new 230/34.5 kV substation site, which is to be owned, operated, and maintained by a wind project developer. The cost for these facilities should be included into the corresponding bids.

   Antelope Transmission Project (ATP) facilities already have been approved by the CPUC including the necessary back-stop provision associated with P.U. Code Section 399.25. As for the Tehachapi Renewable Transmission Project (TRTP), SCE has filed a CPCN application on June 29, 2007 seeking CPUC approvals including the necessary P.U. Code Section 399.25 back-stop provision. In addition, FERC has approved 100% abandoned plant recovery (under certain circumstances) for the ATP and TRTP facilities. Consequently, SCE currently anticipates upfront funding the costs of the Reliability Upgrades associated with the TRTP as well as ATP Segment 1, 2, and 3.

   ATP and TRTP interconnection facilities deemed to be Location-Constrained Resources Interconnection Facilities (LCRIF) 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. The associated costs of these LCRIF were not included in this analysis and should therefore be reflected by each developer into the corresponding bids.

   Projects that request interconnection to non-CAISO controlled (radial 66-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 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, the bid adders below are not able to reflect estimated costs of non-network subtransmission or distribution system upgrades. These costs need to be addressed on a project-by-project basis and should be reflected by each developer into the corresponding bids.

2. Network Facilities

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.

In March 2007, the CPUC issued final decisions on SCE's application for a Certificate of Public Convenience and Necessity (CPCN) for ATP Segment 1 and ATP Segments 2 & 3. Construction of those facilities is currently underway. On June 29, 2007, SCE filed an application for a Certificate of Public Convenience and Necessity (CPCN) with the CPUC for facilities as part of the Tehachapi Renewable Transmission Project (TRTP). TRTP was designed to accommodate approximately 4,500 MW of queued generation, but the amount of generation currently in the CAISO interconnection queue is nearly 15,000 MW. Therefore, significant additional facilities beyond ATP and TRTP will be required to accommodate the generation in the CAISO interconnection queue and the supplemental responses from renewable generation developers in this area.

Study Methodology

Modifications to the previous TRCR were made due to the significant amount of generation projects that have requested interconnection since last year. Based on the size of the interconnection queue, revisions to previous conceptual transmission plans have been made necessary by this recent development of renewable generation and non-renewable development and the order which these requests have been made to the CAISO interconnection queue.

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 either 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.

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. These facilities include the Antelope Transmission Project (ATP), the Tehachapi Renewable Transmission Project (TRTP) and facilities beyond ATP and TRTP.

Antelope Transmission Project (ATP)

The Antelope Transmission Project (ATP) consists of new transmission between Antelope and Pardee, between Antelope and Vincent, and between Antelope and Tehachapi. The project also includes the addition of two new substations in the TWRA. Applications for Certificates for Public Convenience and Necessity (CPCN) for the Antelope-Pardee 500 kV (Segment 1), Antelope-Vincent 500 kV (Segment 2), and Antelope-Tehachapi (Segment 3) 500 kV transmission lines were submitted to the California Public Utilities Commission (CPUC) on December 9, 2004. A supplemental filing for the Antelope-Vincent 500 kV and Antelope-Tehachapi 500 kV transmission lines was submitted on September 30, 2005. The CPUC has issued approvals for these CPCN applications.

Tehachapi Transmission Project (TRTP)

The Tehachapi Renewable Transmission Project (TRTP) is the plan of service developed to interconnect new planned generation resources in the Tehachapi Wind Resource Area (TWRA). These facilities, needed to interconnect and transmit the electrical power from the new planned generation resources, have been identified through a collaborative planning process held as part of the CAISO South Regional Transmission Plan. SCE filed for a CPCN for this project to the CPUC on June 29, 2007. A description of TRTP Segments 4-11 and the latest status of TRTP licensing can be found on the Transmission Projects section of the SCE website (www.sce.com). Summarized below are the major components of these facilities.

Segment 4

- Two new 230 kilovolt (kV) transmission lines traveling approximately 4 miles over new right-of-way (R-O-W) from the Cottonwind Substation to the proposed new Whirlwind Substation.
- A new 500 kV transmission line, initially energized to 230 kV, traveling approximately 16 miles over expanded R-O-W from the proposed new Whirlwind Substation to the existing Antelope Substation.
- New 500 kV transmission lines to loop existing Midway-Vincent No.3 500 kV line in and out of proposed Whirlwind (part of Segment 9) substation.
- Whirlwind 500/230 kV switchyard equipment required to support loop-in and lines to Cottonwind.

Segment 5

- A rebuild of approximately 18 miles of the existing Antelope – Vincent 230 kV T/L and the existing Antelope – Mesa 230 kV T/L to a second single Antelope-Vincent 500 kV T/L over existing R-O-W between the existing Antelope Substation and the existing Vincent Substation.
- Increase operating voltage of initial Antelope-Vincent 500 kV T/L

Segment 6

- A rebuild of approximately 32 miles of existing 230 kV transmission line to 500 kV standards from existing Vincent Substation to the southern boundary of the Angeles National Forest (ANF). This segment includes the rebuild of approximately 27 miles of the existing Antelope – Mesa 230 kV T/L and approximately 5 miles of the existing Rio Hondo – Vincent 230 kV No. 2 T/L.

Segment 7

- A rebuild of approximately 16 miles of existing 230 kV transmission line to 500 kV standards from the southern boundary of the ANF to the existing Mesa Substation. This segment would replace the existing Antelope – Mesa 230 kV T/L.

Segment 8

- A rebuild of approximately 33 miles of existing 230 kV transmission line to 500 kV standards from a point approximately 2 miles east of the existing Mesa Substation (the "San Gabriel Junction") to the existing Mira Loma Substation. This segment would also include the rebuild of approximately 7 miles of the existing Chino – Mira Loma No. 1 line from single-circuit to double-circuit 230 kV structures.

Segment 9

- Whirlwind Substation, a new 500/230 kV substation located approximately 4 to 5 miles south of the Cottonwind Substation near the intersection of 170th Street and Holiday Avenue in Kern County in the TWRA.
- Upgrade of the existing Antelope, Vincent, Mesa, Gould, and Mira Loma Substations to accommodate new transmission line construction and system compensation elements.

Segment 10

- A new 500 kV transmission line traveling approximately 17 miles over new R-O-W between the Windhub Substation and the proposed new Whirlwind Substation.

Segment 11

- A rebuild of approximately 19 miles of existing 230 kV transmission line to 500 kV standards between the existing Vincent and Gould Substations. This segment would also include the addition of a new 230 kV circuit on the vacant

side of the existing double-circuit structures of the Eagle Rock – Mesa 230 kV T/L between the existing Gould Substation and the existing Mesa Substation.

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:

New Substations

One new 500/230 kV collector substation would be required for connection of additional renewable resources in the Tehachapi area. This substation should include up to four 500/230 kV transformer banks, four breaker-and-a-half 500 kV bus positions, six initial breaker-and-a-half 230 kV bus positions, static voltage support devices, and dynamic voltage support devices (if necessary). Additional equipment will be added as renewable generation develops in the region. Timing of complete build-out will be based on actual renewable generation development.

Upgrade Existing Substations

The existing Mesa 230/66 kV substation will be converted to a 500 kV substation. This upgrade is needed to further increase South of Vincent transfer capability. In addition, additional dynamic reactive support will be needed at Rio Hondo Substation and possibly at the new 500/230 kV collector substation.

New or Upgraded Transmission Lines

In order to integrate renewable generation in this area, additional transmission capacity will be required beyond that identified in ATP and TRTP. The transmission requirements are summarized as follows.

- New 15 to 20 mile (depending on location and route) 500 kV transmission line between the new 500 kV Substation and Windhub Substation.
- Second new 16 mile 500 kV transmission line between Windhub Substation and Whirlwind Substation.
- New 15 mile 500 kV transmission line between Whirlwind Substation and Antelope Substation.
- Two new 500 kV transmission lines between Vincent Substation and Mesa Substation, to the extent possible making use of facilities included in TRTP and relocating a significant amount of existing 66 kV facilities between Vincent and Mesa.
- A second new 500 kV transmission line to increase Vincent/Pardee area export capability. For purposes of this analysis, it is assumed that the line will extend from Windhub Substation east to the North of Lugo area and assumed 50 miles distance.

5-5. Transmission Project Cost Estimates for Bid Evaluation

As discussed in the Assumptions Section above, the renewable resources identified were grouped into four geographic areas. Each of these areas will initially result in the inclusion of different facilities for evaluating a transmission bid adder. As the plan of service is completed, however, the bulk of the facilities will be common to all areas. As a result, the same bid adder should be used for all bids in these four clusters. Based on planning level cost estimates for transmission upgrades identified, this bid adder is derived by taking the total project cost for ATP, TRTP and new upgrades identified above and spreading the cost throughout the total generation in the area. 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
- 50 percent for non-renewable
- 85 percent for geothermal

Since non-renewable resources are intermingled with renewable resources in the CAISO interconnection queue, they would share in the use of transmission network upgrades. Therefore, it is only proper to account for non-renewable energy production in developing the proper bid adder because it would result in lowering the corresponding bid adder for renewable resources. Based on the above capacity factors, the total energy production anticipated from all 15,098 MW of generation projects (queued and supplemental responses) is estimated to be 40,291 GWH.

Assuming SCE provides upfront financing for ATP and TRTP, the total capital cost of all of the remaining upgrades is approximately $1.3 billion, with an estimated carrying charge of approximately $208 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. 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 0.52 cents per KWH.

If the cost of ATP and TRTP are included, the total capital cost of all of the upgrades identified is approximately $3.4 billion, with an estimated carrying charge of approximately $544 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. 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 1.35 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 Mono and San Bernardino Counties.

6-2. Renewable Resources

The renewable resources identified by the CEC show that 50 MW were forecasted in 2005 (wind in San Bernardino County), an additional 90 MW are forecasted by 2008 (50 MW of geothermal in Mono County and 40 MW of wind in San Bernardino County), and an additional 820 MW are forecasted by 2017 (30 MW of wind and 300 MW of geothermal in Mono County, and 310 MW of wind and 180 MW of solar in San Bernardino County). These totals are shown below in Table 6-1.

Table 6-1
Renewable Resources Identified by the CEC
CEC's Electric Transmission Plan for Renewable Resources in California
Report to the Legislature dated December 1, 2003

Data Source	Type of Generation	Year			Total
		2005	2008	2017	
CEC Report	Geothermal		50	300	350
	Solar			180	180
	Wind	50	40	340	430
	Annual Total	50	90	820	
	Running Total	50	140	960	

Currently there are a total of 27,439 MW in the CAISO interconnection queue. This includes renewable wind generation projects (5,209 MW), geothermal projects (552 MW), solar projects (18,931 MW), solar photovoltaic projects (1,543 MW), and non-renewable gas-fired projects (1,204 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.

In addition to the queued projects, there were a total of twelve projects identified in supplemental responses from renewable developers. Of these twelve projects, seven of them are already reflected in the CAISO interconnection queue. Of the remaining five projects, one project (35 MW) was specifically included in the bid adder analysis in these clusters. The projects currently in the CAISO queue and the supplemental information obtained are shown in Table 6-2 and Table 6-3. Note that the information in these tables is based on requested in-service dates for projects in the CAISO interconnection queue and may not reflect the latest in-service dates for all projects.

Table 6-2
Supplemental Response from Renewable Resources Developers and
CAISO Interconnection Queue
Based on Location

Location	2008	2009	2010	2011	2012	2013	2014	2015	2016
Control	72			185	210	105			
Inyokern		50	990	465					
Kramer		980	30			200	500		
Victor		160	871	215	160				
Coolwater		293	180	865		676			
Pisgah		850	1744	1530	1512	2550	800	750	
Mountain Pass			514		263	670	230	250	
El Dorado/Mohave	600	635	300	3474		725	1500		
Desert View/Lugo	470			400	500				
Annual Total	1142	2968	4629	7134	2645	4926	3030	1000	0
Running Total	1142	4110	8739	15873	18518	23444	26474	27474	27474

Table 6-3
Supplemental Response from Renewable Resources Developers and
CAISO Interconnection Queue
Based on Technology

Technology	2008	2009	2010	2011	2012	2013	2014	2015	2016
Geothermal	72			200	210	105			
PV		302	521	280	160	280			
Solar	600	1615	2309	2770	2212	1395	3030	1000	
Solar-Other		850		1750		1400			
Wind	470	201	1229	1500	63	1746			
Other			570	634					
Annual Total	1142	2968	4629	7134	2645	4926	3030	1000	0
Running Total	1142	4110	8739	15873	18518	23444	26474	27474	27474

6-3. Study Assumptions and Study Methodology

Study Assumptions

1. Interconnection Facilities

   The resources shown above in Table 6-2 were divided into nine geographic clusters labeled Clusters 2 through 10. Clusters 2, 3 and 4 consist of generation located in the Pisgah, El Dorado/Mohave and Mountain Pass areas. Cluster 5 consists of generation located in the Desert View area. Cluster 6 consists of generation located in the Coolwater area. Clusters 7 and 8 consist of generation located in the Victor and Kramer areas respectively. Cluster 9 consists of generation located in the Inyokern area. The last cluster, Cluster 10, consists of generation located in the Control area.

   It was assumed that generation in Cluster 2 would be interconnected to the existing Pisgah 230-kV substation by generator owned facilities (i.e. gen-ties) for which costs should be included into the bid. It was also assumed that generation in Cluster 3 would interconnect to facilities that ultimately deliver the corresponding generation output to either the El Dorado or Mohave switchyards. Such deliveries can be made by directly connecting the projects to these substation sites with generator owned facilities (i.e. gen-ties), for which costs should be included into the bid, or by scheduling from Arizona, Nevada, and Wyoming to these two locations. It was assumed that generation in Cluster 4 would be interconnected to a new collector substation by generator owned facilities (i.e. gen-ties) for which costs should be included into the bid.

   It was assumed that generation in Cluster 5 would be interconnected to a new collector substation by generator owned facilities (i.e. gen-ties) for which costs should be included into the bid.

   It was assumed that generation in Cluster 6 would be interconnected to the existing (expanded) Coolwater 230-kV Substation by generator owned facilities (i.e. gen-ties) for which costs should be included into the bid.

   It was assumed that the generation resources in Cluster 7 would be connected to the existing Victor 230 kV substation by generator owned facilities (i.e. gen-ties) for which costs should be included into the bid. Likewise, it was assumed that the generation resources in Cluster 8 would be connected to the existing Kramer 230 kV substation by generator owned facilities (i.e. gen-ties) for which costs should be included into the bid.

   It was assumed that the generation in Cluster 9 would be connected to a new proposed Inyokern 230 kV substation by generator owned facilities (i.e. gen-ties) for which costs should be included into the bid.

It was assumed that the generation in Cluster 10 (near the California-Nevada border) would be connected to Control by generator owned facilities (i.e. gen-ties) for which costs should be included into the bid.

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 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.

2. Network Facilities

Delivery of the energy from the nine clusters shown above in Table 6-3 would require significant upgrades to existing network facilities. Generally speaking, the closer the renewable resource is located to the Lugo substation, the lower the number of upgrades to transmission facilities would be required. Once the power is delivered to Lugo, additional upgrades will be needed to deliver the generation resources to the corresponding load pockets. Similar to the Tehachapi plan of service, upgrades south of Vincent will be needed to off-load the currently constraint south of Lugo path (Lugo to Mira Loma). SCE has identified a project (Mira Loma-Vincent 500 transmission line) to increase south of Lugo capability which is needed to serve load by 2011. This project is expected to allow for an additional 1,000 MW of deliveries south of Lugo. Since the project is needed for service to load, no bid adder will be assigned for this project.

Beyond 1,000 MW, additional upgrades will be needed to further increase north to south system capability. Based on the Tehachapi Plan of Service, the upgrades that would benefit the north of Lugo area are the same as the additional south of Vincent upgrades which include new lines from Vincent to Mesa, a new line from the Tehachapi area to the North of Lugo area, and the installation of voltage support devices. These new transmission lines, including the new Mira Loma-Vincent 500 kV, are expected to allow for an additional delivery from the north to the south of to accommodate the identified generation in this area. As such, bid adders for these lines will be included for delivery north of Lugo area resources.

Study Methodology

Modifications to the previous conceptual plans 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. 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
- 50 percent for non-renewable
- 20 percent for pump-storage
- 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.

Upgrade Existing Substations

The following substations will be expanded to accommodate upgrades to existing transmission lines or the termination of new transmission or substation equipment.

- The Inyokern Substation will need to be expanded to 230 kV.
- Both Kramer and Pisgah Substations will need to be expanded to 500 kV.
- The existing Lugo Substation will require expansion to accommodate additional 500/230 kV transformer capacity.
- The existing Coolwater 230-kV Substation will require expansion to allow it to serve as a new collector substation in the area.

New Substations

In order to fully integrate the total renewable generation identified in this area, the following new substations will be required.

- A new 500 collector substation would be needed between the existing Lugo and Pisgah substations
- A new 230 kV collector substation would be needed between Mountain Pass and Eldorado.
- A new 500 kV collector substation would be needed in the Eldorado/Mohave area
- Two new HVDC converter stations to support area export

New or Upgraded Transmission Lines:

In order to fully integrate the total queued generation project in this area, significant additional transmission capacity will be required. This will involve the construction of new facilities and/or the replacement of existing lower capacity transmission with higher capacity transmission. The transmission requirements are summarized as follows:

- Approximately 1175 miles of new 500-kV transmission lines connecting the 500 kV substations including Lugo, Kramer, Pisgah, Eldorado and the new 500/230 kV transmission substations.
- Approximately 625 miles of new or rebuilt 230-kV transmission lines
- Approximately 100 miles of new HVDC line to support area export
- Approximately 35 miles of new or rebuilt 115-kV transmission lines

6-5. Transmission Project Cost Estimates for Bid Evaluation

Facilities for Cluster 2 (Pisgah)

Cluster 2 Level 1: 0 MW

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

Cluster 2 Level 2: Up to 9,736 MW

Level 2 represents the available capacity after the inclusion of upgrades to accommodate projects currently in the CAISO interconnection queue. The upgrades consist of the following:

- Upgrade Pisgah Substation to 500-kV
- Remove existing Lugo-Pisgah 230-kV and replace with 500 kV
- Loop existing Eldorado-Lugo 500-kV into Pisgah
- Loop existing Lugo-Mohave 500-kV into Pisgah
- Construct new 500-kV line from new sub east of Lugo to Pisgah
- Construct new 500-kV line from new sub east of Lugo to Kramer
- Loop Lugo-Pisgah 500-kV line into new substation
- Upgrade Kramer Substation to 500-kV
- Construct new 500-kV line from Kramer to North of Vincent area
- Construct new HVDC line to support area export from North of Lugo/East of Lugo area to LA Basin area
- Construct new Vincent-Mesa 500-kV lines and upgrade Mesa to 500-kV

The estimated capital cost of these upgrades is $3.6 billion, with an estimated annual carrying charge of $571 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 1.05 cents per KWH.

Note that this area is outside of the area defined by current SCIT operating procedure; therefore even with the upgrades, Southern California area import limits for system stability may result in curtailment of renewable resources in this cluster even with the upgrades identified.

Facilities for Cluster 3 (El Dorado/Mohave)

Cluster 3 Level 1: 0 MW

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

Cluster 3 Level 2: Up to 7,234 MW

Level 2 represents the available capacity after the inclusion of upgrades to accommodate projects currently in the CAISO interconnection queue. The upgrades include the upgrades identified for Cluster 2, level 2 plus the following:

- Additional 500-kV Eldorado-Pisgah lines for Eldoraro area import

The estimated capital cost of these upgrades is $3.6 billion, with an estimated annual carrying charge of $571 million. The bid adder for this cluster 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 0.95 cents per KWH.

Note that this area is outside of the area defined by current SCIT operating procedure; therefore even with the upgrades, Southern California area import limits for system stability may result in curtailment of renewable resources in this cluster even with the upgrades identified.

Facilities for Cluster 4 (Mountain Pass)

Cluster 4 Level 1: 0 MW

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

Cluster 4 Level 2: Up to 1,927 MW

Level 2 represents the available capacity after the inclusion of upgrades to accommodate projects currently in the CAISO interconnection queue. In addition to the upgrades listed in Clusters 2 and 3 above, the additional upgrades required include the following:

- New 230/115 kV collector substation west of Eldorado
- Construct new double circuit 230-kV line between the new substation and the existing Eldorado 230-kV Substation

The estimated capital cost of all these upgrades is $3.7 billion, with an estimated annual carrying charge of $594 million. The bid adder for this cluster 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 1.66 cents per KWH.

Note that this area is outside of the area defined by current SCIT operating procedure; therefore even with the upgrades, Southern California area import limits for system stability may result in curtailment of renewable resources in this cluster even with the upgrades identified.

Facilities for Cluster 5 (Lugo/Desert View)

Cluster 5 Level 1: 0 MW

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

Cluster 5 Level 2: Up to 1,370 MW

Level 2 represents the available capacity after the inclusion of upgrades to accommodate projects currently in the CAISO interconnection queue. These upgrades, a subset of the upgrades identified for Cluster 2, level 2 above, include the following:

- Construct new 500-kV line from new sub to Pisgah
- Construct new 500-kV line from new sub to Kramer
- Loop existing Lugo-Pisgah 500-kV line into new substation
- Upgrade Kramer Substation to 500-kV
- Construct new 500-kV line from Kramer to North of Vincent area
- Construct new HVDC line to support area export from North of Lugo/East of Lugo area to LA Basin area
- Construct new Vincent-Mesa 500-kV lines and upgrade Mesa to 500-kV

The estimated capital cost of all these upgrades is $2.7 billion, with an estimated annual carrying charge of $432 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 0.70 cents per KWH.

Note that this area is outside of the area defined by current SCIT operating procedure; therefore even with the upgrades, Southern California area import limits for system stability may result in curtailment of renewable resources in this cluster even with the upgrades identified.

There were two extremely large identified projects (5,000 MW total) in supplemental information provided by developers that identified Lugo substation as the point of interconnection. These projects are not included in the MW total above, in part due to the assumption that a significant amount of queued generation in this area will withdraw from the queue through the ongoing CAISO GIPR process. Therefore, it is assumed that the adder of 0.70 cents per KWH is applicable for these two projects as well.

Facilities for Cluster 6 (Coolwater)

Cluster 6 Level 1: 0 MW

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

Cluster 6 Level 2: Up to 2,014 MW

Level 2 represents the available capacity after the inclusion of upgrades to accommodate projects currently in the CAISO interconnection queue. These upgrades include the following:

- Construct new 230-kV line between Coolwater and new sub east of Lugo
- Tear-down and rebuild 230-kV lines between Coolwater and Kramer
- Expand Coolwater 230-kV as a new 230-kV collector substation
- Upgrade Kramer Substation to 500-kV
- Construct new 500-kV line from Kramer to North of Vincent area
- Construct new HVDC line to support area export from North of Lugo/East of Lugo area to LA Basin area
- Construct new Vincent-Mesa 500-kV lines and upgrade Mesa to 500-kV

The estimated capital cost of these upgrades is $2.2 billion, with an estimated annual carrying charge of $344 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 0.90 cents per KWH.

Note that this area is outside of the area defined by current SCIT operating procedure; therefore even with the upgrades, Southern California area import limits for system stability may result in curtailment of renewable resources in this cluster even with the upgrades identified.

Facilities for Cluster 7 (Victor 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 1,406 MW

Level 2 represents the available capacity after the inclusion of upgrades to accommodate projects currently in the CAISO interconnection queue. These upgrades include the following:

- Construct new 230-kV line between Victor and Lugo
- Increase Lugo Substation AA-bank capacity
- Tear-down-and-rebuild existing Kramer-Lugo 230-kV
- Upgrade Kramer Substation to 500-kV
- Construct new 500-kV line from Kramer to North of Vincent area
- Construct new HVDC line to support area export from North of Lugo/East of Lugo area to LA Basin area
- Construct new Vincent-Mesa 500-kV lines and upgrade Mesa to 500-kV

The estimated capital cost of these upgrades is $2.1 billion, with an estimated annual carrying charge of $341 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 0.80 cents per KWH.

Note that this area is outside of the area defined by current SCIT operating procedure; therefore even with the upgrades, Southern California area import limits for system stability may result in curtailment of renewable resources in this cluster even with the upgrades identified.

Facilities for Cluster 8 (Kramer 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 1,710 MW

Level 2 represents the available capacity after the inclusion of upgrades to accommodate projects currently in the CAISO interconnection queue. These upgrades include the following:

- Increase Lugo Substation AA-bank capacity
- Tear-down-and-rebuild existing Kramer-Lugo 230-kV
- Upgrade Kramer Substation to 500-kV
- Construct new 500-kV line from Kramer to North of Vincent area
- Construct new HVDC line to support area export from North of Lugo/East of Lugo area to LA Basin area
- Construct new Vincent-Mesa 500-kV line and upgrade Mesa to 500-kV

The estimated capital cost of these upgrades is $2.1 billion, with an estimated annual carrying charge of $336 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 0.96 cents per KWH.

There were two extremely large identified projects (1,800 MW total) in supplemental information provided by developers that identified this area as the point of interconnection. These projects are not included in the MW total above, in part due to the assumption that a significant amount of queued generation in this area will withdraw from the queue through the ongoing CAISO GIPR process. Therefore, it is assumed that the adder of 0.96 cents per KWH is applicable for these two projects as well.

Note that this area is outside of the area defined by current SCIT operating procedure; therefore even with the upgrades, Southern California area import limits for system stability may result in curtailment of renewable resources in this cluster even with the upgrades identified.

Facilities for Cluster 9 (Inyokern)

Cluster 9 Level 1: 0 MW

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

Cluster 9 Level 2: Up to 1,505 MW

Level 2 represents the available capacity after the inclusion of upgrades to accommodate projects currently in the CAISO interconnection queue. These upgrades include the following:

- Construct new 230-kV between Inyokern and Kramer
- Upgrade Inyokern Substation to 230-kV
- Upgrade Kramer Substation to 500-kV
- Tear-down-and-rebuild existing Kramer-Lugo 230-kV
- Construct new 500-kV line from Kramer to North of Vincent area
- Construct new HVDC line to support area export from North of Lugo/East of Lugo area to LA Basin area
- Construct new Vincent-Mesa 500-kV line and upgrade Mesa to 500-kV

The estimated capital cost of these upgrades is $2.3 billion, with an estimated annual carrying charge of $360 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 1.64 cents per KWH.

Note that this area is outside of the area defined by current SCIT operating procedure; therefore even with the upgrades, Southern California area import limits for system stability may result in curtailment of renewable resources in this cluster even with the upgrades identified.

Facilities for Cluster 10 (California/Nevada Border)

Cluster 10 Level 1: 0 MW

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

Cluster 10 Level 2: Up to 572 MW

Level 2 represents the available capacity after the inclusion of upgrades to accommodate projects currently in the CAISO interconnection queue. These upgrades include the facilities identified for Cluster 9, Level 2 plus the following:

- Construct new 230-kV between Control and Inyokern

The estimated capital cost of these upgrades is $2.6 billion, with an estimated annual carrying charge of $414 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 1.87 cents per KWH.

The total MW capacity in this cluster (572 MW) consists of 537 MW of queued generation and one renewable project that was identified in this area (35 MW) in supplemental information provided by renewable developers.

Note that this area is outside of the area defined by current SCIT operating procedure; therefore even with the upgrades, Southern California area import limits for system stability may result in curtailment of renewable resources in this cluster even with the upgrades identified.

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 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 for Imperial and Riverside Counties show that 320 MW are forecast for 2005 (200 MW of wind and 120 MW of geothermal), an additional 250 MW are forecast by 2008 (190 MW of wind and 60 MW of geothermal), and an additional 410 MW are forecast by 2017 (140 MW of wind, 190 MW of geothermal, and 80 MW of Biomass). These totals are shown below in Table 7-1.

Table 7-1
Renewable Resources Identified by the CEC
CEC's Electric Transmission Plan for Renewable Resources in California
Report to the Legislature dated December 1, 2003

Data Source	Type of Generation	Year			
		2005	2008	2017	Remaining Potential[3]
CEC Report	Geothermal	120	60	190	1,580
	Biomass	0		80	
	Wind	200	190	140	1,300

Currently there are a total of 14,945 MW in the CAISO interconnection queue. This includes renewable wind generation projects (945 MW), solar projects (6,010 MW), solar photovoltaic projects (4,330 MW), geothermal projects (300 MW), and non-renewable gas-fired projects (3,360 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.

In addition to the queued projects, there were a total of thirteen supplemental responses from renewable developers identifying this area as an area of interest. Of these responses, eleven of them are either existing projects or projects in the CAISO interconnection queue. The remaining two projects are projects off-system (150 MW geothermal in IID). The projects currently in the CAISO queue and the supplemental information obtained are shown in Table 7-2 and Table 7-3. Note that the information in these tables is based on requested in-service dates for projects in the CAISO interconnection queue and may not reflect the latest in-service dates for all projects.

[3] Remaining potential was obtained from conceptual report titled SCE Renewable Conceptual Transmission Plan dated August 29, 2003 adjusted based on revised CEC resources identified from 2005 to 2017.

Table 7-2
Supplemental Response from Renewable Resources Developers and
CAISO Interconnection Queue
Based on Location

Location	2008	2009	2010	2011	2012	2013	2014	2015	2016
Devers	908	111	778		2000				
Midpoint			700	1520	1600	2800	250		
Eagle Mountian/Julian Hinds	150	600	1048	1680	250	250			
IID	300	50			100				
Annual Total	1358	711	2526	3200	3850	3050	250	0	0
Running Total	1358	2119	4645	7845	11795	14845	15095	15095	15095

Table 7-3
Supplemental Response from Renewable Resources Developers and
CAISO Interconnection Queue
Based on Technology

Technology	2008	2009	2010	2011	2012	2013	2014	2015	2016
Geothermal	300	50			100				
PV	150	400	1180	600	2000				
Solar		200	300	1910	1850	1750			
Wind	58	111	526				250		
Other	850		520	690		1300			
Annual Total	1358	711	2526	3200	3850	3050	250	0	0
Running Total	1358	2119	4645	7845	11795	14845	15095	15095	15095

7-3. Existing System Conditions and Currently Proposed Projects

The revised conceptual studies were performed for adding additional renewable resources to the existing system and taking into consideration currently proposed projects. The following is a brief discussion of the existing system conditions and currently proposed projects:

Existing System

The existing SCE transmission system in the vicinity of the renewable generation development in Imperial and Riverside Counties includes 500-kV, 230-kV, and 115-kV transmission facilities. A major 500-kV system tie between Arizona and California is used to import power from the Palo Verde area. The IID 230-kV system is connected to SCE's Devers and Mirage 230-kV substations by the Coachella-Devers and Coachella-Mirage 230-kV lines which form Transmission 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. In addition, the Devers-Mirage 115-kV subtransmission system is currently operated in parallel with the bulk power transmission system and contains a total of 728 MW of wind generation and 135 MW of gas-fired generation. All resources delivered to the Devers area is ultimately transmitted to the SCE load centers by four 230-kV transmission lines (commonly referred to as West-of-Devers) and one 500-kV transmission line (Devers-Valley No. 1 500-kV).

Currently Proposed Projects

1. Devers-Palo Verde No.2 500-kV Line

   The Devers-Palo Verde No.2 500-kV line (looped through Harquahala and Hassyampa generating stations) is currently proposed and under evaluation to further increase the total East of River flow by 1,200 MW. This project consists of constructing a new 500-kV transmission line from Devers to Harquahala, constructing a second 500-kV line from Devers to Valley, and installing additional Static VAR Compensators within SCE's system.

2. West of Devers (WOD) Upgrades

   The project was proposed to mitigate identified thermal overloads under severe local system conditions. The project proposal is to upgrade the four 230-kV lines west of Devers Substation to increase the transfer capacity from Devers westbound.

3. Devers-Mirage 115-kV System Split

   As discussed above, the existing Devers-Mirage 115-kV system is currently operated in parallel with the Bulk Power network. There is a project in place which calls for splitting the system as a result of thermal overloads associated

with load growth. This project would result in the formation of two radial 115-kV networks.

4. Midpoint Substation

Midpoint Substation is a proposed 500-kV switching station near the vicinity of the California-Arizona border and the existing Devers-Palo Verde 500-kV line. Midpoint Substation had been proposed as a substation to be used as a collector station for queued generation projects, including renewables, in this geographic area.

7-4. Study Assumptions and Study Methodology

Study Assumptions

1. Interconnection Facilities

   The resources shown above in Table 7-3 were divided into four clusters. The first cluster consists of wind, solar, PV, hydro pump-storage, and non-renewable gas-fired generation near the California-Arizona border near Midpoint Substation. The second cluster consists of solar, PV and wind generation in the Eagle Mountain/Julian Hinds area. The third cluster consists of wind, PV and non-renewable gas-fired generation in the vicinity of Devers Substation. The fourth cluster consists of geothermal generation in Imperial County.

   It was assumed that generation in Clusters 11 and 13 would be interconnected to Midpoint Substation or Devers Substation (respectively) by radial 230-kV or 500-kV gen-tie facilities, the costs of which should be included in the respective bids. For Cluster 12, it was assumed that generation would connect to a new collector substation by new 230-kV gen-tie facilities, the cost of which should be included in the respective bids. For Cluster 14, projects that are connected to the IID system are assumed to deliver to the CAISO system via (expanded) Path 42.

   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 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.

2. Network Facilities

   Delivery of the four clusters discussed above would require upgrades to existing network facilities.

   As discussed above, two existing 230-kV transmission lines interconnect geothermal generation located in Imperial Irrigation District's (IID) service territory. These lines (Path 42) are currently used to schedule an existing 472 MW of geothermal under SCE contract to the SCE load center. Since the path is rated at 600 MW, it was assumed that the remaining capacity could only be used to interconnect up to 128 MW of additional geothermal resources. Since the

existing and anticipated generation development in IID is primarily renewable, scheduling renewable resources against other renewable resources due to Path 42 constraints is counterproductive for meeting RPS goals. Therefore it is assumed that an expansion of Path 42 capability will be required for renewable generation resources located in IID to deliver to CAISO system via Path 42.

Upgrades on the four West of Devers transmission lines are assumed required for renewable generation development in clusters 11 through 14.

Study Methodology

Modifications to the previous conceptual plans were extensive in the Eastern area due to significant size of the CAISO interconnection queue, which consists primarily but not exclusively of eligible renewable generation projects. 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
- 50 percent for non-renewable
- 20 percent for pump-storage
- 85 percent for geothermal

Deliveries to SDG&E were assumed to be made to the existing San Onofre 230-kV substation. It should be noted that such deliveries may 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 can be achieved by either upgrading South of San Onofre (Path 44) or developing additional SCE-SDG&E system ties. See SDG&E Conceptual studies for further details.

Deliveries to PG&E were assumed to be made to the existing Midway 500-kV substation assuming the existing Path 26 transmission facilities can accommodate such increase in imports into PG&E. It should be noted that such deliveries may necessitate an increase in South-North Path 26 capability as well as an increase in transmission capacity to the PG&E load center. Such increases can be achieved by further upgrades to the existing Path 26 transmission facilities or construction of a fourth Midway-Vincent 500-kV transmission line. See PG&E Conceptual studies for further details.

7-5. Transmission Project Cost Estimates for Bid Evaluation

Facilities for Cluster 11 (Midpoint)

Cluster 11 Level 1: 0 MW

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

Cluster 11 Level 2: Up to 6,870 MW

Level 2 represents the available capacity after the inclusion of upgrades to accommodate projects currently in the CAISO interconnection queue. The upgrades consist of the following:

- New Midpoint 500/230-kV Substation
- New 500-kV Substation east of Devers ("Desert Center")
- Construction of new 500-kV line from Midpoint Substation to new 500-kV substation east of Devers
- New Desert Center-Valley 500-kV line
- New Serrano-Valley 500-kV line
- West of Devers 230-kV upgrades
- New 500-kV line for area export (conceptual Devers-Mira Loma 500-kV)

The estimated capital cost of these upgrades, not including DPV2 and the Devers-Valley No. 2 500-kV line, is $1.7 billion, with an estimated annual carrying charge of $267 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 1.13 cents per KWH.

If the cost of DPV2 and Devers-Valley No. 2 are included, the estimated capital cost of these upgrades increases to $2.1 billion, with an estimated annual carrying charge of $331 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 1.48 cents per KWH.

Note that this area is outside of the area defined by current SCIT operating procedure; therefore even with the upgrades, Southern California area import limits for system stability may result in curtailment of renewable resources in this cluster even with the upgrades identified.

Facilities for Cluster 12 (Eagle Mountain/Julian Hinds)

Cluster 12 Level 1: None

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

Cluster 12 Level 2: Up to 3,778 MW

Level 2 represents the available capacity after the inclusion of upgrades to accommodate projects currently in the CAISO interconnection queue. The upgrades consist of the following:

- New 230-kV collector substation
- New 500-kV Substation east of Devers ("Desert Center")
- New 230-kV transmission between new collector substation and new "Desert Center" 500-kV substation
- New Desert Center-Valley 500-kV line
- New Serrano-Valley 500-kV line
- West of Devers 230-kV upgrades
- New 500-kV line for area export (conceptual Devers-Mira Loma 500-kV)

The estimated capital cost of these upgrades, not including DPV2 and the Devers-Valley No. 2 500-kV line, is $1.4 billion, with an estimated annual carrying charge of $218 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 0.82 cents per KWH.

If the cost of DPV2 and Devers-Valley No. 2 are included, the estimated capital cost of these upgrades increases to $1.5 billion, with an estimated annual carrying charge of $233 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 0.86 cents per KWH.

Note that this area is outside of the area defined by current SCIT operating procedure; therefore even with the upgrades, Southern California area import limits for system stability may result in curtailment of renewable resources in this cluster even with the upgrades identified.

Facilities for Cluster 13 (Devers)

Cluster 13 Level 1: None

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

Cluster 13 Level 2: Up to 3,997 MW

Level 2 represents the available capacity after the inclusion of upgrades to accommodate projects currently in the CAISO interconnection queue. The upgrades consist of the following:

- New Serrano-Valley 500-kV line
- West of Devers 230-kV upgrades
- New 500-kV line for area export (conceptual Devers-Mira Loma 500-kV)

The estimated capital cost of these upgrades, not including the Devers-Valley No. 2 500-kV line, is $490 million, with an estimated annual carrying charge of $78 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 0.64 cents per KWH.

If the cost of Devers-Valley No. 2 is included, the estimated capital cost of these upgrades increases to $590 million, with an estimated annual carrying charge of $94 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 0.77 cents per KWH.

Facilities for Cluster 14 (IID via Path 42)

Cluster 14 Level 1: None

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

Cluster 14 Level 2: Up to 450 MW

Level 2 represents the available capacity after the inclusion of upgrades to accommodate projects currently in the CAISO interconnection queue. The upgrades consist of the following:

- New Serrano-Valley 500-kV line
- New Devers-Coachella double-circuit 230-kV line (Path 42)
- West of Devers 230-kV upgrades
- New 500-kV line for area export (conceptual Devers-Mira Loma 500-kV)

The estimated capital cost of these upgrades, not including the Devers-Valley No. 2 500-kV line, is $570 million, with an estimated annual carrying charge of $91 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 0.46 cents per KWH.

If the cost of Devers-Valley No. 2 is included, the estimated capital cost of these upgrades increases to $670 million, with an estimated annual carrying charge of $107 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 0.47 cents per KWH.

There were two projects (total 150 MW) in the IID system indicated in the supplemental information provided by developers included in the 450 MW total above. The Path 42 upgrades identified above and the network upgrades within the SCE system (i.e. West of Devers) would be sufficient to accommodate this additional renewable generation development in IID.

Note that this area is outside of the area defined by current SCIT operating procedure; therefore even with the upgrades, Southern California area import limits for system stability may result in curtailment of renewable resources in this cluster even with the upgrades identified.