Multi-Area Real-Time Transmission Line Rating Study

Author
Dyer, Jim

Publication Date
2008-02-01

FINAL PROJECT REPORT

MULTI-AREA REAL-TIME TRANSMISSION LINE RATING STUDY

Prepared for CIEE By:

Electric Power Group, LLC

Project Manager: Jim Dyer
Authors: Jim Dyer, John Balance

Date: February, 2008

A CIEE Report

DISCLAIMER

ACKNOWLEDGMENTS

The project team would like to thank and acknowledge the following organizations (in alphabetical order) and individuals for their participation in the project through interviews:

CalEnergy—Vincent Signoratti and Greg Merrigan

California Independent System Operator—Dariush Shirmohammadi, Gary DeShazo, and Jim McIntosh

Imperial Irrigation District—David Barajas and Joel Fugett

Los Angeles Department of Water and Power—Ken Silver

Pacific Gas & Electric—Chifong Thomas, Matt Stevens and Ryan Stanley

Powerex—Ali Yazdi and Jeff Lam

Sacramento Municipal Utility District—Vicken Kasarjian

San Diego Gas & Electric—Linda Brown

Sempra Generation—Leslie Padilla

Southern California Edison—Gary Tarplee and John Pespisa

Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by binging environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Energy Commission), conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

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Transportation

California Transmission Congestion Assessment is the draft final report for the California Transmission Congestion Assessment Project, CIEE Award # C-0606, WA BOA 142 under CEC/CIEE Prime Contract No. 500-99-013, research conducted by Electric Power Group. The information from this project contributes to PIER's Strategic Energy Research Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/pier or contact the Energy Commission at 916-654-5164.

Table of Contents

List of Figures

List of Tables

Abstract

A transmission line or path is said to be congested when its transfer capability is insufficient to accommodate all needed power transfers and unscheduled power flows. Needed power transfers may result from market dispatch, economic dispatch, or reliability needs.

Within the CA ISO grid, congestion is separated into three distinct categories: inter-zonal congestion (less than 10% of the total cost of congestion); intra-zonal congestion (30% to 40% of total congestion costs); and, Reliability Must Run (RMR) (over 50% of total congestion costs). Congestion costs during 2002 to 2006 have ranged from $420 million to $1,077 billion annually.

Eliminating congestion across certain paths may be more costly than the resulting reduction in energy dispatch costs. Therefore, some level of congestion on key paths is both expected and cost effective.

Based on both a comparison with other Regional Transmission Operators and Independent System Operators, a reasonable level of CA ISO grid congestion costs would be 2-5 percent of total energy costs ($250-650 million in 2006 dollars).

The CA ISO and Participant Transmission Owners (PTO) must identify those lines/paths that would be large contributors to future congestion and determine, through an appropriate process, which would be economical to upgrade or enhance.

Keywords: Congestion, inter-zonal, intra-zonal, Reliability Must Run, transmission, grid, CA ISO

Executive Summary

Since the 2001 California electricity crises, California Independent System Operator (CA ISO) congestion costs have been a concern to policymakers and CA ISO. The cost of congestion and reliability must-run contracts that are designed to address local congestion and reliability, have ranged from approximately $420 million to $1 billion annually since 2002.

Because of both the relative size of the CA ISO control area, representing 80 percent of the total California load, and the greater public availability of operational details regarding the CA ISO operations, this congestion assessment focused its numerical analysis on the CA ISO control area. Moreover, congestion is most clearly visible in the open access transmission scheduling paradigm of the CA ISO, where parties can request transmission service in excess of the capabilities of the grid, making it possible to track congestion. For the non-CA ISO portions of the California grid, there is simply no data available from which to determine the extent, if any, of congestion that exists on that portion of the grid.

A transmission line or path is said to be congested when its transfer capability is insufficient to accommodate all needed power transfers and unscheduled power flows. Needed power transfers may be the result of market dispatch, economic dispatch, or reliability needs.

Congestion may arise in different operations time periods, such as Day-ahead congestion, Hour-ahead congestion, or Real-time operation, and the consequences of congestion may include uneconomic dispatch (higher energy costs) or curtailment of customer loads. In some cases, eliminating congestion across certain paths may be more costly than the resulting reduction in energy dispatch costs. Therefore, some level of congestion on key paths is both expected and cost effective.

Within the CA ISO grid, congestion is separated into three distinct categories, inter-zonal, intra-zonal and Reliability Must Run (RMR) (a condition where a local area transmission system may not operate reliably because of insufficient generation within the local area.)

For the CA ISO grid, the total cost of congestion includes the cost of redispatch (adjusting generation output) to eliminate both inter-zonal (10 percent of cost) and intra-zonal congestion (40 percent of costs), as well as the above-market costs for RMR generation (both the fixed contract charges and the dispatch energy charges) (50 percent of cost). The CA ISO's transmission congestion costs have been trending lower over the past three years, with a 40 percent decline in costs from 2004 to 2006. Based on both a comparison with other Regional Transmission Operators (RTOs) and Independent System Operators (ISOs), a reasonable level of transmission congestion costs in the CA ISO grid would be in the range of $250-650 million (in 2006 dollars). This would put congestion costs in the range of 2-5 percent of total energy costs.

As significant as the current congestion costs are, they represent a relatively small portion of the total cost of energy to consumers in the CA ISO control area. Congestion costs have added between $2.06 to $4.54 per megawatt-hour (MWh) or 4.6 to 8.3 percent to the cost of energy during 2002 to 2006.

In reviewing the top 16 congested transmission paths in California in 2005-2006 it was observed that approximately 15 percent ($41.7 million) of the total inter- and intra-zonal congestion costs in 2005 and 13 percent ($34 million) in 2006 was attributed to upgrade outages. These should not be reoccurring costs since once the upgrades are complete, transmission congestion is significantly reduced going forward.

While transmission congestion is disruptive of the smooth functioning of the energy marketplace, the costs to fully eliminate all transmission congestion may greatly exceed its impact on the market. The challenge to the CA ISO and to the Participant Transmission Owners (PTO) is to identify those lines/paths that would, in the future, be large contributors to congestion, and determine which would be economical to upgrade or enhance. The costs of upgrades are (generally) significant – in the range of several million dollars for even the simplest upgrades. It may not be cost-effective to fix the grid to reduce congestion across a specific path or line if the expected on-going congestion savings are less than threshold levels. This suggests that a screening approach to transmission congestion may be warranted.

High congestion magnitude, high price differential, or high duration alone cannot generate a high annual cost of congestion, but a combination of the three can generate significant congestion costs. When high congestion costs are present, the causes and annual repeatability of those costs must also be assessed.

There is a lot of anecdotal discussion that shapes policymakers' view of congestion. It is important to understand the magnitude, duration, economic impact, and persistence of congestion to understand whether it is good public policy to expend resources to eliminate congestion. Having a congestion-free grid is not economically justifiable. All congestion is not bad.

Following are some of the key policy observations that are contained in this report and are meant to inform and guide decision-makers:

1. In the long term, congestion can only be avoided by planning and constructing sufficient transmission in advance to manage any remaining congestion costs to acceptable levels.
2. The current transmission planning/licensing process requires proof of congestion costs before new transmission lines are authorized.
    a. Congestion costs must rise high enough to warrant grid upgrades.
    b. Forecast congestion (or economic opportunities) as justification for new transmission is challenged during licensing, and all available options are exhaustively investigated as preferred over new transmission.
3. The current congestion monitoring mechanisms do not forecast future congestion or adequately measure current congestion.
4. Integration of intermittent resources to meet Renewable Portfolio Standard (RPS) goals is likely to adversely impact congestion.

Research Findings and Conclusions:

This research effort has focused on understanding the congestion problem and providing a context to guide policy and research initiatives related to congestion. Below are the most important six of the 18 key research findings and conclusions that are contained in this report.

1. CA ISO congestion cost data understates the amount of congestion that exists. It captures information related only to schedules attempted, as compared to the full economic potential for transactions.
2. Inter-zonal congestion causes higher prices for all energy within the zone. This price impact is not captured in current congestion cost assessments.
3. Reliability Must Run is the largest single component of congestion costs.
4. Without the construction of new local generation, RMR costs can only be reduced by expanding the transmission capabilities into constrained local areas.
5. Congestion can only be avoided by planning and constructing sufficient transmission in advance to manage any remaining congestion costs to acceptable levels.
6. Metrics are needed to identify and classify congestion costs as actionable, manageable, or monitor.

Project Recommendations:

The research identified several recommended actions related to data sharing, planning, and future research activities, as summarized below:

1. The CA ISO needs to continue its active participation on the Western Electricity Coordinating Council's (WECC's) Transmission Expansion Planning Policy Committee, which provides both oversight to the planning process and guidance in the analysis and modeling for WECC economic transmission expansion planning.
2. The CA ISO needs to provide a more open planning process as it relates to transmission congestion as well as information transparency. Most market participants interviewed felt they had little or no knowledge of congestion issues or access to meaningful data and information.
3. CA ISO should expedite activities to implement locational marginal pricing (LMP), so as to provide the Load Serving Entities with adequate price signals related to their generating resource commitment (startup and dispatch) during planned transmission outages.
4. As RMR is gradually phased out, the CA ISO and Participating Transmission Owners (PTOs) will need to ensure that market participants and the California Public Utilities Commission (CPUC) have clear visibility of all options and related costs associated with meeting local capacity requirements. This would provide guidance for resource procurement activity in the impacted local areas.

5. The California utilities are not likely to be able to significantly reduce the need for RMR generation through the construction of local generation due to the challenges of siting new generation in metropolitan areas. In light of this, the CA ISO and the PTO's will need to actively seek solutions that will increase transmission into local areas so as to reduce RMR costs going forward.
6. To ensure California's utilities can meet their RPS goals, there is a need for the CA ISO and PTOs to define infrastructure requirements (in a phased approach) and associated costs to ensure deliverability of other renewable technologies that are located within the state.
7. While the annual congestion costs for most of the inter- and intra-zonal transmission paths are below the threshold to warrant transmission upgrade, two paths, South of Lugo and Palo Verde, consistently showed sufficiently high congestion costs to warrant investigation for further upgrades. Southern California Edison's proposed development of the second Devers-Palo Verde 500 kV transmission line will address the Palo Verde path congestion. Investigation of additional upgrades of the South of Lugo path is warranted, especially since it is very likely that some future renewables energy will flow over this path.
8. The Energy Commission needs to continue its funding of research projects related to transmission congestion.

1.0 Introduction

California transitioned to a competitive wholesale market structure in 1998 with the formation of the California Independent System Operator (CA ISO). CA ISO operates approximately three-quarters of California electric grid. Since the 2001 California electricity crises, CA ISO congestion costs have been a concern to policymakers and CA ISO. The cost of congestion and reliability must-run contracts that are designed to address local congestion and reliability, have ranged from approximately $420 million to $1 billion annually since 2002. However, baseline information and data on congestion—location, timing, cause, patterns, magnitude, or duration—is not easily available or understood. This study focuses on developing a baseline understanding of congestion to help guide policy, research, and planning for congestion management and mitigation.

Congestion can simply be defined as the inability to schedule all the requested energy transactions due to transmission limitations. Congestion has always been in existence; however, it was not very visible before the start of CA ISO operations. Prior to the implementation of the deregulated electricity market and the start of operation of the California Independent System Operator in 1998, California's experience with transmission congestion was limited to real-time operations, since the transmission path operator, in the day-ahead, would not accept request for service beyond the path capability. Prior to 1998, congestion was primarily managed in the form of schedule curtailments due to transmission forced outages, changes in the path's capability due to various factors (e.g., generation inertia, remote path flows), but mostly as a result of unscheduled or loop flow causing a path's actual flow to exceed limits. The unscheduled flow was mitigated in part by the coordinated operation of the Western Electricity Coordinating Council phase shifters in an effort to accommodate and control unscheduled flow.

Unscheduled flow is a naturally occurring phenomenon on an AC electric grid, which results in electrical power flowing over all parallel paths between the source of generation and the load, in proportion to the impedances of those paths. Unscheduled flow, when additive to high schedules on some of the major intertie transmission lines, cause overloads on those lines, requiring the curtailment or reduction of power schedules.

Additionally, prior to 1998, the utilities' strategy for generation dispatch consisted of utilizing at least a minimum amount of their own generation located close to their major load pockets to serve the local load for local reliability. The transmission systems into those load pockets were used to provide the remainder of the energy needed in the local areas based on economic dispatch. While the dispatch of a pre-defined amount of local generation did incur some additional fuel expense compared to an unconstrained least cost economic dispatch, it was the lowest total cost solution as the fuel premium was less costly than the alternative of upgrading the transmission grid (in a vertically integrated utility operation, where the fixed costs of generation ownership was included in customer rates). With deregulation and the divestiture of the utility-owned local generation, and the expectation that the price of energy would rise to the level needed to support the independent ownership of generation, special contracts (called

Reliability Must Run contracts, or RMR) were needed (between the CA ISO and the local generator owners) which allowed the CA ISO to order the start-up and operation of local generation to prevent transmission overloads, and prevented the owners from charging excessive prices for essential generation operation. The RMR contracts provided the generator owners with a fixed payment for being available to the CA ISO, plus a payment for the energy actually scheduled.

Under the deregulated market structure of the CA ISO, load serving entities were encouraged to arrange and schedule their energy supplies from the lowest price providers, regardless of their physical location on the grid and without (initial) concern about the deliverability of that energy. The CA ISO had in place protocols to identify those combinations of schedules that would overload transmission facilities, and methods by which the schedules could be adjusted to avoid the overloads. These protocols are collectively referred to as the Congestion Management Protocols. As a major element of these protocols, when congestion occurs on the grid and prevents energy from flowing as scheduled, the CA ISO must *redispatch* various generators, reducing output from those contributing to the congestion and increasing the output from other generators that, because of their location, can deliver energy to the intended area. This redispatch of generation resources has an associated cost (congestion charges) that reflects those costs (e.g., start-up, minimum load, higher heat rate) that will be incurred in dispatching the less efficient generation resources. Those parties wishing to continue their original scheduling across those congested paths, and not be subjected to a redispatch, simply pay the associated congestion charges.

During the initial operation of the CA ISO-controlled transmission grid, there was very little congestion, mirroring the operation of the grid pre-deregulation. However, during the energy crisis of 2000-2002, the level of transmission congestion grew dramatically, and the level of transmission congestion and its associated charges (e.g., $420 million in 2000) became a significant industry concern, both at the operations level and at the regulatory level. Key transmission paths became the focus of state and federal regulators, to the point that in a May 11, 2000 interview in *The Wall Street Journal*, Energy Secretary Bill Richardson said, "America is a superpower, but it's got the grid of a Third World nation." In the interview, Richardson had predicted that electricity shortages and blackouts would plague the west coast that summer and his predictions came true with 54 interruptions of non-firm load and 8 interruptions of firm load during the years 2000 and 2001. Path 15 was high on his list of transmission weaknesses.

The cost of congestion has been highly variable. In the past three years, the total cost of transmission congestion has declined from $1.08 billion in 2004 to $611 million in 2006, a 43% reduction from the high-water mark of 2004. But questions remain about congestion—what does this decline mean, is it the beginning of a trend, and should policymakers be concerned about spending over half a billion dollars on congestion annually?

This report reviews California recent congestion experience, addresses the causes of congestion, and when to be concerned about congestion in the electric grid. It identifies top congested paths and is designed to help guide policy, research, and planning initiatives related to congestion management and mitigation.

2.0 Project Background, Overview and Objectives

2.1. Purpose

The purpose of this project is to perform a scoping study to document the scope and magnitude of the congestion problems facing the State of California and to report the challenges in forecasting congestion. This scoping study will provide a building block for guiding policy, congestion planning, and future research related to congestion management and forecasting.

2.2. Project Objectives

The objectives of this project were:

Perform a scoping study to document

- Scope and magnitude of congestion problems facing California.
- Identify top congested paths.
- Review historical congestion patterns.
- Assess proposed solutions.
- Outline research challenges and approaches to forecasting congestion.

Get input from the four major Control Area Operators

- California Independent System Operator.
- Imperial Irrigation District.
- Los Angeles Department of Water and Power.
- Sacramento Municipal Water District.

Get input from the Transmission Owners

- Pacific Gas & Electric Company.
- San Diego Gas & Electric Company.
- Southern California Edison Company.

Get input from Independent Power Producers (IPPs) and Merchant Scheduling Coordinators

- Sempra.
- Powerex.
- CalEnergy.
- Others.

Prepare a primer document on transmission congestion and future research requirements related to congestion.

Prepare reports, briefings and participate in public forums as appropriate.

2.3. Project Approach

The research approach used for this project included the following components:

Data Collection

- Review of CA ISO Annual Reports on Market Issues and Performance.
- Establish contact, obtain data from CA ISO and utilities, and analyze congestion.

Conduct interviews with Transmission Control Areas, utility energy schedulers, and independent energy schedulers (a list of the organizations interviewed is included in Appendix A, Agencies/Entities Interviewed) to develop a broad view of the impact of congestion on the major stakeholders.

Produce report of findings and a transmission congestion primer.

3.0 Project Findings and Conclusions

3.1. California Grid Characteristics

The California electric grid is divided into five control areas, which are operated by five different entities:

California Independent System Operator.

Imperial Irrigation District.

Los Angeles Department of Water and Power.

Sacramento Municipal Utility District.

Turlock Irrigation District.

The California electric grid has 16 interconnections with its neighboring states in the WECC, with a total transfer capability of 18,000 MW. The CA ISO control area represents approximately 80% of the California load. The CA ISO operates its system as three electrical zones: NP15, SP15, and ZP26. The map in Figure 1 presents an overview of the California grid, interconnections, and control areas.

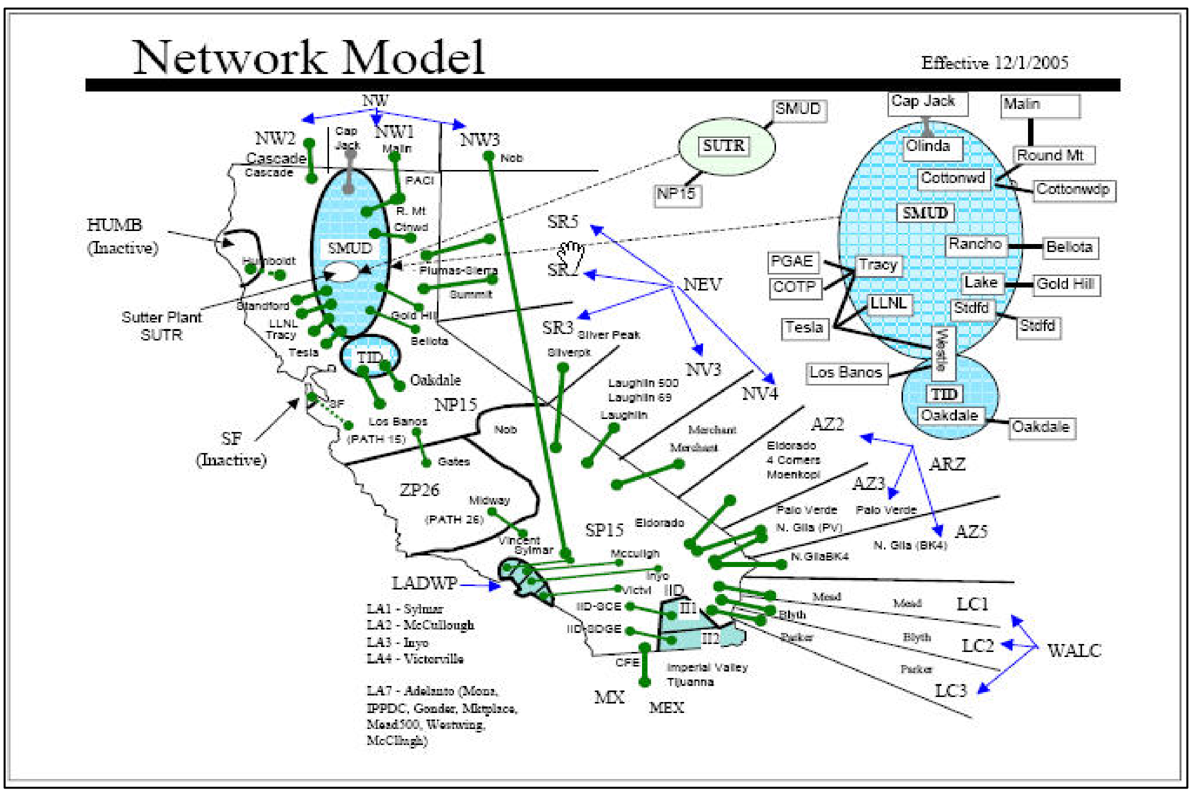

Figure 1. California Network Map (Source - CA ISO)

Because of both the relative size of the CA ISO control area, representing 80% of the total California load, and the greater public availability of operational details regarding the CA ISO operations, this congestion assessment focused its numerical analysis on the CA ISO control area. Interviews with three of the four other control area operators confirmed that focusing the numerical assessment on the CA ISO grid (and associated protocols) would provide a representative assessment of transmission congestion in California. Moreover, congestion is most clearly visible in the open access transmission scheduling paradigm of the CA ISO, where parties can request transmission service in excess of the capabilities of the grid, making it possible to track congestion. Non-ISO utilities (including the municipal utilities within California) typically do not offer transmission service for sale unless transmission capacity is available. Thus the non-ISO utilities do not normally receive requests for service in excess of capacity, nor do they typically track needs for more transmission capacity than they have available at the time. Finally, the non-ISO vertically integrated utilities typically construct or procure sufficient transmission to meet their own grid needs, and except during extreme conditions, do not experience overloads on their own transmission systems. Thus, this assessment of transmission congestion is relevant mostly for the CA ISO grid and open access scheduling paradigm.

3.2. Congestion

Congestion is a condition that exists when the requests for or actual power transfers (both scheduled and unscheduled) across a transmission facility (element or set of elements), when netted, would exceed the transfer capability of such facility, resulting in violations of the physical, operational, or policy constraints under which the grid operates in the normal state or under any one of the contingency cases in a set of specified contingencies (e.g., Normal – 1 [N-1]).

Congestion may arise during the day-ahead dispatch, the hour-ahead dispatch, and the real-time operations of the system, in the balancing market.

3.2.1. Definition of Congestion

A transmission line or path is said to be congested when its transfer capability is insufficient to accommodate all needed power transfers and unscheduled power flows. Needed power transfers may be the result of market dispatch, economic dispatch, or reliability needs. The consequences of congestion may include:

- Uneconomic dispatch resulting in higher consumer costs.
- Reliability mitigation measures resulting in curtailment of customer loads.
- Congestion may arise in different operations time periods.
- Day-ahead congestion (identified and adjusted during the day-ahead scheduling process).
- Hour-ahead congestion (identified and adjusted during the hour-ahead scheduling process).

- Real-time operation (identified when the overload is occurring, and adjusted by altering real-time energy schedules so as to remain in compliance with North American Electric Reliability Corporation (NERC) and WECC Operating Standards.

Congestion may also be identified during the long term planning assessment process, such as in the Local Capacity Requirements assessments or in the annual transmission planning. As load grows within transmission-constrained sub-areas, the congestion assessment process should identify a need for either transmission expansion or the development and/or procurement of additional local generating capacity.

3.2.2. Congestion Categories

Within the CA ISO grid, congestion is separated into three distinct categories:

Inter-zonal congestion between zones and at interconnections

- Defined as congestion between zones, e.g., NP15, ZP26, SP15, as well as interconnections with other control areas.
- Managed in day-ahead and hour-ahead markets, e.g.,
    - Import limitations such as on the California Oregon Interconnection (COI) or Southern California Import Transmission (SCIT).
    - North to South flow limitations on Path 26 (3 - Midway-Vincent 500 kV lines).
- CA ISO collects these congestion revenues from the facility users and distributes them to Congestion Revenue Rights (CRR) Holders and/or Participant Transmission Owner (PTO).

Intra-zonal where congestion within a zone can be linked to a specific transmission line or path

- Defined as congestion within a CA ISO zone and linked to a specific transmission line or path.
- Managed in real-time through re-dispatch of generators with costs assigned to PTOs where possible.
- Major intra-zonal congestion paths or regions identified
    - Mission-Miguel.
    - South of Lugo.

Local Reliability Congestion or Reliability Must Run (RMR) is a condition where a local area transmission system may not operate reliably because of insufficient generation within the local area. A generating unit is categorized as a potential RMR unit if its unavailability could have a detrimental impact on reliability under specified operating conditions. Normally, a Local RMR Area describes a part or pocket of the transmission system that contains load, generation and transmission facilities that are inter-dependent. Figure 2 is a map showing 9 Local RMR Areas within the CA ISO control area. RMR is:

- Defined as congestion within a zone and linked to local resource deficiency.
- Managed on an annual basis.

- Costs consist of annual contract capacity and day-ahead energy, both of which are assigned to PTOs.

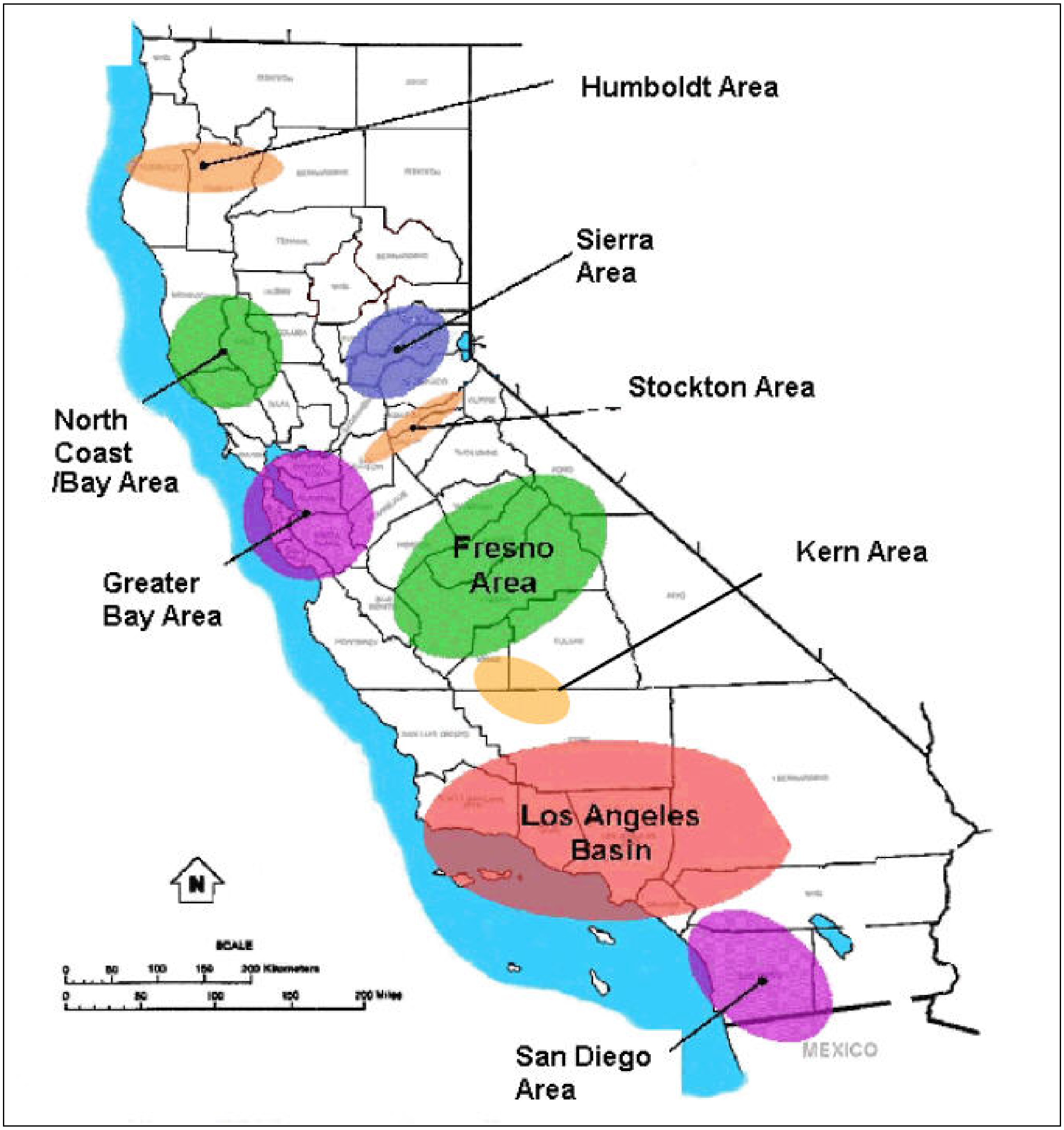

Figure 2. Local RMR Areas (Source - CA ISO)

3.2.3. Common Causes of Congestion

Congestion occurs because of one or more of the following conditions:

- Transmission facilities (operating normally) are inadequate to support the requested or needed power transfers.
- Adequate transmission facilities exist, but are temporarily restricted, limiting power transfer capability.
- Local transmission constraints resulting from local generation not operating, increasing the demand on the transmission grid beyond its capability.
- Local demand substantially higher than forecast.

Congestion can arise from a wide range of causes, many of which are temporary and transitional in nature. These include:

- Equipment outages (either generation or transmission).
- Hydro conditions and weather patterns—surplus hydro, droughts, cold snaps and heat storms can cause a change in normal flows and trading patterns.
- Market dispatch can result in energy schedules that exceed the capacity of specific transmission links (inter-zonal congestion) or paths (intra-zonal congestion).
- Local reliability requirements—market dispatch within a transmission-bounded region may be inadequate to meet local reliability requirements (e.g., RMR requirements).
- Resource surpluses—e.g., merchant generation built around Palo Verde switchyard with inadequate transmission to fully accommodate all the generation.
- Transmission capacity curtailments—due to maintenance, construction outages (inter- and intra-zonal congestion) or reliability criteria (such as operating nomograms).
- Inadequate transmission capability between two areas or regions.
- Congestion may be transitory or one-time events (e.g., outages), or persistent (e.g., resource surpluses, RMR conditions).

While all of the above conditions could be said to be the result of inadequate transmission, it does not necessarily follow that building additional transmission to reduce or eliminate specific congestion conditions would be either economical or desirable. The cost of the additional transmission facilities needed to reduce or eliminate congestion across any specific line or path must be compared to the cost of simply accommodating the level of congestion forecast to occur over the foreseeable future (the economic period over which the transmission line would be assessed). Eliminating congestion across certain paths may be more costly than the resulting reduction in energy dispatch costs. Therefore, some level of congestion on key paths is both expected and cost effective.

Congestion that results from planned maintenance outages or outages related with system upgrades may be mitigated through better coordination between the CA ISO and the Load Serving Entity’s (LSE’s) use of new transmission technologies (wind/temperature measuring devices) and implementation of Locational Marginal Prices (LMP). The implementation of LMP would provide immediate feedback to the LSE on their planned resource commitment under the outage condition(s).

There is value in the PTOs and CA ISO performing some analysis to develop sets of geographic diverse solutions (e.g., DSM) that can be implemented to mitigate the impacts of congestion associated with short duration outages or system upgrades.

3.3. Cost of Congestion

For the CA ISO grid, the total cost of congestion includes the cost of redispatch to eliminate both inter-zonal and intra-zonal congestion, as well as the above-market costs for RMR generation (both the fixed contract charges and the dispatch energy charges). Table 1 presents the total congestion charges for the CA ISO grid for the period 2002-2006.

Table 1. Total Congestion Costs ($ Millions)

Congestion category	2002	2003	2004	2005	2006
Inter-zonal	42	26	56	55	56
Intra-zonal	6	151	426	222	207
RMR (net of intra-zonal component)	371	422	595	433	348
Total	420	600	1077	710	611

(Source – CA ISO)

Transmission congestion costs have been trending lower over the past three years, as illustrated by the 40% decline in costs from 2004 to 2006.

Inter-zonal congestion costs represent less than 10% of the total cost of congestion, which would tend to indicate that CA ISO's interties to neighboring systems as well as the major ties between the CA ISO zones have sufficient capacity to accommodate most energy schedules. As will be discussed later in this report, however, this may be an inaccurate conclusion.

The inter-zonal congestion costs shown in Table 1 represent the costs accumulated during the day-ahead congestion management process. During this process, if the total schedules submitted for power deliveries across a specific path exceed the capability of that path, the CA ISO may adjust schedules based on schedule adjustment bids submitted by the scheduling coordinators. The accumulated cost of the schedule adjustments represents the congestion cost. A similar process is used to identify and reduce scheduled congestion in the hour-ahead scheduling process. In the current day operation, with the exception of forced outages or high unscheduled flow (a.k.a. loop flow), there is very little real-time inter-zonal transmission congestion, and thus little real-time adjustment of generation schedules to eliminate that congestion.

Intra-zonal congestion is only managed in the real-time market and its costs are about 30% to 40% of the total cost of congestion. However, because intra-zonal congestion does not occur repeatedly on clearly identified paths, it may be more challenging to identify specific transmission improvements to reduce the level of this category of congestion. In many cases, both the inter- and intra-zonal congestion documented were a result of planned outages related to system or path upgrades.

RMR costs account for over 50% of the total cost of congestion. RMR costs are closely linked to local reliability issues and load pockets, and may be a target for reduction through transmission upgrades, as will be discussed later in this report.

As significant as these congestion costs are, they represent a relatively small portion of the total cost of energy to consumers in the CA ISO control area (energy costs measured at the delivery point to the local distribution company (LDC), exclusive of the LDC's transmission and distribution delivery charges). Table 2 illustrates the energy cost impact of congestion on the total cost of energy from 2002 through 2006.

Table 2. Energy Cost Impact of Congestion ($/MWh)

	2002	2003	2004	2005	2006
Cost of energy and A/S	43.01	47.95	50.15	54.76	44.88
Cost of congestion	2.06	2.8	4.54	3.06	2.67
Total cost of energy and congestion	45.07	50.75	54.69	57.82	47.55
Congestion as % of Total Cost	4.6%	5.5%	8.3%	5.3%	5.6%

(Source – CA ISO)

By comparison, during the past three years, the PJM Regional Transmission Operator (RTO) area in the Eastern Interconnection experiences congestion impacts in the range of 7.7 to 9.4% of the total energy costs, and the ERCOT (Texas) interconnection experiences congestion impacts in the range of 1.7 to 2.5% of total energy costs as discussed in more detail in Section 5.3.5.

3.3.1. RMR Costs Have Declined

The portion of total congestion costs due to Reliability Must Run requirements has declined in recent years, as illustrated in Table 3 below.

Table 3. RMR Costs ($ Millions)

	2002	2003	2004	2005	2006
Fixed Option Payment	NA	NA	359	252	259
Pre-Dispatch Costs	NA	NA	236	182	88
Total RMR Costs	372	423	595	433	348

(Source – CA ISO)

The decline has been caused by several factors:

- The portion of the RMR generation selecting the non-market form of the RMR contract continues to decrease, resulting in lower variable cost payments.
- The non-market generating capacity accounted for 11.8% of the 2006 RMR capacity compared to 19.6% for 2005.

- The construction of new local generation, coupled with recent construction and upgrades of transmission into constrained sub-areas have further reduced the RMR dispatch requirements.

As mentioned earlier, RMR costs are related to insufficient transmission capability to serve the local area load without the operation of some local generation. These costs include fixed capacity payments, and energy payments for actual dispatch. Over half the RMR costs are for fixed capacity payments. RMR costs have declined significantly from 2004 due to improvements in the local transmission systems. RMR costs can be further reduced by expanding transmission system capability into constrained local areas and the continued implementation of the CPUC's local resource adequacy procurement process. As a result of both transmission enhancements and local resource additions, for 2007, the CA ISO was able to reduce the number of RMR power plants needed in the future for local reliability. This reduction represents a drop of nearly 60%, from 120 units or 9,963 megawatts to 65 units equaling 3,995 megawatts.

Going forward, the CA ISO is working collaboratively with the California Public Utilities Commission to incorporate the local RMR requirements, which are now being called Local Capacity Requirements, into the CPUC's Resource Procurement Standards. As that transition is completed, the CA ISO will no longer hold RMR contracts for the operation of local generation, while the local utilities will hold procurement contracts for that same or new generation. As a result of this change in procurement responsibility, the visibility of the premium costs associated with RMR generation at the CA ISO level will diminish, as those premium costs will transition from a transmission cost to a resource procurement cost borne by local utilities. Only in the case where insufficient resources are procured in a local area will the CA ISO procure the required RMR contract as a back-stop provision. In the event the CA ISO is required to procure back-stop generation and if all the LSEs have fulfilled their obligations to procure the required LCR (as adopted by the CPUC), the back-stop generation cost will be spread to all LSEs.

The challenge going forward will be to identify the appropriate amount of LCR in the annual LCR studies so as to minimize the LCR procurement costs, but sustain energy costs high enough to provide an incentive for generation to locate in the load pockets.
Also, to better assist the LSEs and CPUC in the resource procurement process, the CA ISO, in conjunction with the PTOs, needs to provide the price tag for transmission projects that would eliminate the reliability need for existing and/or new local generation. This price tag would provide the LSE and CPUC with an upper limit for any resource procurement premiums that might be paid as an incentive for a generator's location.

3.3.2. Inter- and Intra-zonal Costs

Inter- and intra-zonal congestion costs are the result of inadequate transmission to accommodate all requested deliveries. Expanding the transmission paths can reduce these costs. Relatively few paths account for the bulk of the congestion costs, but the pattern of congestion changes from year to year, caused by such variations as:

- Strong hydro production in the northwest.
- High Northern California hydro production.

Forced outages of key transmission lines both inside and outside of California contribute to congestion inside California. Additionally, transmission outages to upgrade lines and equipment add to intra- and inter-zonal congestion costs during the outages, but dramatically reduce future congestion costs. Table 4 presents the top congested transmission paths in California in 2005-2006.

The top 16 congested paths accounted for $133.3 million of congestion costs in 2005, and $103.8 million in 2006. This represents nearly 48% of the total inter- and intra-zonal congestion costs in 2005 ($279 million), and 39% of the costs for 2006 ($263 million). The bulk of the remaining congestion costs were identified in the CA ISO reports as system or zonal costs not associated with specific paths.

While the total inter- and intra-zonal congestion costs may have been similar over the recent past, the pattern of congestion changes from year to year, such as a threefold increase for NOB from 2005 to 2006 and an 80% reduction for Miguel from 2005 to 2006.

Table 4. Top Congested Paths in California

Path	Causal Assignment	2005 Congestion Cost ($ Million)	2006 Congestion Cost ($ Million)
South of Lugo	Intra-Zonal	45.7	37.6
Palo Verde	Inter-Zonal	19.8	17.1
PACI	Inter-Zonal	6.7	12.1
Eldorado	Inter-Zonal	4.7	6.7
South of Pastoria/ South of Magunden	Intra-Zonal	10.1	6.1
NOB	Inter-Zonal	1.8	5.6
IPPDC Adelanto	Inter-Zonal	1.9	4.3
Path 26	Inter-Zonal	7.2	3.4
Mead	Inter-Zonal	1.2	3.2
Miguel	Intra-Zonal	14.4	2.7
Path 15	Inter-Zonal	2.2	1.9
Adelanto	Inter-Zonal	0.7	1.6
Cortina-North Geyser	Intra-Zonal	4.7	1.4
Blythe	Inter-Zonal	8.7	0.1
Sylmar	Intra-Zonal	2.4	0.0
North Gila Bank	Intra-Zonal	1.1	0.0
Total		133.3	103.8

Construction and maintenance outages can have a significant impact on reported transmission congestion. Table 5 summarizes the transmission congestion costs attributed to upgrade outages during 2005-06. These upgrade outages resulted in $41.7 million of congestion costs in 2005, and $34 million in 2006. This corresponds to approximately 15% of the total inter- and intra-zonal congestion in 2005 and 13% in 2006. However, on some paths, a large portion of congestion resulted from outages, for example, Palo Verde, PACI, Eldorado, South of Pastoria, Path 26, and Cortina in 2005. Also, once the upgrades are completed, transmission congestion is significantly reduced going forward.

Table 5. Congestion Costs Due to Upgrade Outages

Path	Causal Assignment	2005 Congestion Cost ($ Million)		2006 Congestion Cost ($ Million)	
		Recorded	Cost of Upgrade Outages	Recorded	Cost of Upgrade Outages
South of Lugo	Intra-Zonal	45.7	0.0	37.6	2.0
Palo Verde	Inter-Zonal	19.8	14.1	17.1	9.9
PACI	Inter-Zonal	6.7	4.0	12.1	5.8
Eldorado	Inter-Zonal	4.7	4.0	6.7	0.1
South of Pastoria/ South of Magunden	Intra-Zonal	10.1	10.0	6.1	5.9
NOB	Inter-Zonal	1.8	0.0	5.6	2.8
IPPDC Adelanto	Inter-Zonal	1.9	0.0	4.3	0.0
Path 26	Inter-Zonal	7.2	4.9	3.4	2.3
Mead	Inter-Zonal	1.2	0.0	3.2	1.0
Miguel	Intra-Zonal	14.4	0.0	2.7	1.6
Path 15	Inter-Zonal	2.2	0.0	1.9	1.4
Adelanto	Inter-Zonal	0.7	0.0	1.6	0.0
Cortina-North Geyser	Intra-Zonal	4.7	4.7	1.4	1.2
Blythe	Inter-Zonal	8.7	0.0	0.1	0.0
Sylmar	Intra-Zonal	2.4	0.0	0.0	0.0
North Gila Bank	Intra-Zonal	1.1	0.0	0.0	0.0
Total		133.3	41.7	103.8	34.0

Mitigating annual congestion costs of $1 million across a single path can support an investment of only $5.0–6.5 million (assuming 15–20% annual carrying charges). Unfortunately, for many of the major paths, the incremental cost of the next upgrade is significant, as most of the low-cost options to increase the path capacity have already been exhausted. For instance, when Path 15 was upgraded, the upgrade required the construction of a third 500 kV line between Gates and Los Banos Substations, together with upgrades to several parallel 115 kV and 230 kV lines to accomplish the desired 1,500 MW transmission capacity upgrade. The Path 15 upgrade project was completed for a total cost of $250 million, which translates to an annual carrying charge of $37.5-50 million per year. In contrast, the highest annual congestion cost associated with Path 15 was $43 million in 2001, but the CA ISO's economic studies for the Path 15 expansion reflected an annual benefit of up to $83 million under the scenario where NP15 is very deficient in generation stemming from modeling a dry hydro year (approximately a one in ten year) and low new generation build out in NP15 and the Pacific Northwest.

Significant improvements in the California grid, together with the construction of additional in-state generation, have caused inter- and intra-zonal transmission congestion to diminish.

Improvement projects have been undertaken in all parts of the state, with $4.5 billion in grid upgrades approved by the CA ISO. However, with statewide load expected to increase by 20% by the year 2030, and the need to construct nearly 60,000 MW of new generation (30,000 MW to meet load growth, and 30,000 MW to replace obsolete retiring generation), the potential for new transmission congestion is real. Another driver for potential new transmission congestion is California's aggressive Renewable Portfolio Standard (RPS) and the fact that most renewable resources are remote from the load centers. This will require a significant investment in infrastructure to ensure the renewable energy can be delivered to all portions of the California grid. Long range transmission planning will help to identify the transmission grid pressure points, and to develop plans to mitigate the forecast congestion. New study tools and techniques may be needed to adequately identify potential future congestion, and to support its mitigation without the necessity to *live with it for a while* before policymakers are convinced that the congestion is real.

In October, 2007, the U.S. Department of Energy designated the Southwest Area National Interest Electric Transmission Corridor, as a national interest electric transmission corridor pursuant to FPA section 216(a)(2). In its studies, the FPA also identified four *Congestion Areas of Concern*, areas where a large-scale congestion problem exists or may be emerging but more information and analysis appear to be needed to determine the magnitude of the problem. These four areas included (1) New England, (2) Phoenix-Tucson area, (3) San Francisco Bay area and (4) Seattle-Portland area. These designations reinforce that transmission congestion is both a significant national interest, and an economic concern to the region.

3.3.3. Summary of Interview Comments

As part of this investigation, interviews were conducted with representatives from the control area operators, the transmission owners, the municipal utilities, and market participants (both utility and non-utility market participants). The interviews investigated the following issues:

1. What transmission lines or facilities are most impacted by congestion?
2. Does congestion cause operational and/or planning issues in the delivery of its resource portfolio to the California market?
3. When do the parties experience the greatest impacts from congestion (e.g., summer, winter, off-peak hours)?
4. Does the party monitor and track the magnitude and duration of the congestion it experiences (such as curtailed energy or required-must-run [RMR] generation)?
5. Does the party monitor and track the cost impacts of congestion (curtailed energy or RMR)?
6. In the CA ISO control area, who has the responsibility to resolve or mitigate congestion issues, including Reliability Must Run costs?
7. In the CA ISO control area, what is the process to go through to mitigate congestion? (Who has to approve proposed mitigation?)
8. Are the current processes for managing and mitigating congestion acceptable to the party? If not, what should the processes be?

9. Does the party have criteria for when it is beneficial to eliminate or mitigate areas of congestion?
10. Is the party able to forecast potential congestion and mitigate it before it becomes a reality?
11. What is the party doing to eliminate or mitigate those areas of congestion, including RMR?
12. Is the CA ISO doing all it should to manage and mitigate congestion? If not, what more should it be doing?
13. Are the CPUC and Federal Energy Regulatory Commission (FERC) doing all they should to assist in the management and mitigation of congestion? If not, what more should they be doing?

Interviews were conducted with 11 organizations as listed below:

Control Area Operators	Transmission Owners	Market Participants
▪ CA ISO	▪ San Diego Gas & Electric	▪ Cal Energy
▪ Los Angeles Department of Water and Power	▪ Southern California Edison	▪ Powerex
▪ Sacramento Municipal Utility District	▪ Pacific Gas & Electric	▪ Southern California Edison
▪ Imperial Irrigation District		▪ Sempra

Excerpts from the interviews are presented below:

Real Time Congestion

1. The 500 kV congestion is not much of a challenge, since there are normally adequate resources available to re-dispatch and congestion at this level is not an everyday issue.
2. Need to do economic studies to determine whether building additional transmission is needed
    a. 20% of the time, congestion on the interties is an issue, aggravated by outages.
    b. On high load days, the control area operators see the least congestion.
    c. The day-ahead market does not account for unscheduled flow (loop flow), which defers mitigation of unscheduled flow to the real time market.
3. The 230 kV and 115 kV systems are much more aggravating for day-to-day operations. The grid operators don't have the local resource pool to mitigate congestion. Few of the units that are effective will be on-line during non-peak days
    a. Not building/reinforcing lines fast enough to offset the congestion, caused by changing flow patterns (e.g., imports, expanding load areas).

Congestion Management Challenges

1. The utility energy managers are optimizing the dispatch for the lowest next cost of energy based on CPUC criteria.
2. The utility energy managers will be assigned the costs for out of sequence dispatch, but there is a 45-60 day settlement lag. Thus, the utilities don't receive effective feedback on the cost consequences of congestion.
3. The utility energy managers have to commit least cost dispatch based on vague CA ISO information about upcoming outages.
4. Implementation of LMP will help reduce intra-zonal congestion costs as it will provide utility energy managers with a price impact for their planned resource commitment and resolve many of the issues in the day-ahead rather than having to solve them in real time.

Congestion Management Tools, Data and Issues

1. Renewables complicate the congestion management issue, especially the wind.
2. The energy schedulers do not track or retain any data related to congestion as well as its cost impacts, but do track the actual and schedule impacts on an hourly basis to effectively manage the issues.
3. There may not be the right mix of generating resources available to mitigate congestion.
4. Energy schedulers don't look for energy if transmission is not available and as a result they are not tracking missed opportunities and associated congestion.
5. A lot of the congestion is hidden inside the intra-zonal congestion and RMR, so the external parties have little price signal to respond.
6. The transmission planning process needs more municipal utility participation.
7. There is no access to any real time congestion information – the energy schedulers need more transparency.
8. The Control Area Operators have not found a pattern in the congestion.
9. Congestion means requests for transmission service in excess of the capability of the system at the time – but the CA ISO uses a more narrow definition - schedules that are rejected during the congestion management process.
10. Congestion on the lines is not measured.
11. Congestion data for real time not recorded.
12. Information on congestion from the CA ISO tends to be general information infrequently communicated through informal statements.
13. CA ISO does not disclose in real time or near real time the congestion in the system.
14. There is definitely a need for more information and data from the CA ISO regarding the magnitude of congestion on specific paths.

15. Lack of certain knowledge of where new generation will be constructed makes future planning more challenging.
16. Don't know where the new generators are, how big they are, who they are, and who will be the final winners. A different approach could be that the CA ISO performs congestion analysis and shares the information with the PTOs.

As reflected in the interview comments, in recent years, congestion on the bulk power grid (the 500 kV portion) has been low. The grid operators have more challenges managing the local congestion (such as in the local reliability sub-areas), due in large part to the relative lack of local generation options. Part of this lack of local generation options is due to the inability of the market participants (the LSEs and the energy marketers) to see any indications of local congestion, as this information is not readily available from the grid operations. While the energy settlement process does reveal the local congestion and the cost impact of a less than optimal resource commitment, that information only becomes available 45-60 days after the fact. Moreover, the LSE energy schedulers are obligated to develop least cost energy schedules. However, these schedules may not be achievable due to transmission congestion, yet the LSEs have little visibility of the transmission limitations that would prevent their schedules from being fully implemented. The CA ISO congestion management protocols enable the grid operators to manage the grid, but the costs of so doing are passed (through the billing system) to the LSEs too late to allow any meaningful readjustment of schedules to achieve lower overall costs.

The CA ISO measures inter-zonal congestion as the adjustment of requested schedules for energy delivery across the inter-zonal boundaries. This methodology fails, however, to accurately capture all of the economic cost of existing or future congestion. This is best illustrated by the economic studies of the Devers-Palo Verde No. 2 (DPV 2) 500 kV line expansion project. The CA ISO's economic studies, performed as part of the CA ISO's assessment of Southern California Edison's proposal to construct the second Devers-Palo Verde 500 kV transmission line, identified significant economic benefits (for year 2008, savings of $39-110 million, based on the CA ISO Ratepayer/CA ISO Ratepayer + Contract Path savings) to California customers, more than sufficient to offset the $620 million construction cost of the line. This assessment was based on the economics of importing additional power from existing generation in the Palo Verde area into the California grid. Arguably, the availability of this existing energy for economic import into California would show up as requested energy schedules each and every day, and reflecting a large annual congestion charge on the Devers-Palo Verde path. However, as illustrated in Table 4, the congestion charges on the Devers-Palo Verde path are relatively low ($17-20 million annually), of which over half the charges are due to construction-related outages. The remaining congestion charges principally reflect the day-to-day schedules that are marginally being congested off the path. The disparity between the economic assessments of the potential value of constructing the second line and the "measured" inter-zonal congestion across the path indicates that the CA ISO's measurement of congestion is capturing only a small portion of the potential congestion. To fully assess the potential for economic transmission congestion, the CA ISO will need to perform economic studies of grid expansion options similar to those performed in its assessment of the DPV 2 line.

3.3.4. Congestion Mitigation Options

While transmission congestion is disruptive of the smooth functioning of the energy marketplace, the costs to fully eliminate all transmission congestion may greatly exceed its impacts on the market. The challenge to the CA ISO and to the PTOs is to identify those lines/paths that would, in the future, be large contributors to congestion, and determine which would be economical to upgrade or enhance. The costs of upgrades are (generally) significant – in the range of several million dollars for even the simplest upgrades. For complex paths, multiple line upgrades may be needed to achieve a path capacity increase. To be economically efficient, the market benefits of reducing congestion should exceed the annualized carrying charges for the upgrades. It may not be cost-effective to fix the grid to reduce congestion across a specific path or line if the expected on-going congestion savings are less than threshold levels. This suggests that a screening approach to transmission congestion may be warranted.

As illustrated in Table 6 below, annual congestion costs below $25 million/year across a specific path or into a local zone may be economically efficient to accept – so-called economic congestion. For annual congestion costs above $25 million/year, it may be efficient to modify the transmission grid to eliminate the cause of the congestion costs across a path or into a local zone. For the years 2005 and 2006, only the South of Lugo and Palo Verde paths exceeded $10 million in annual congestion costs, and would be candidates for transmission expansion.

Scenarios of low, medium, and high congestion costs and congestion mitigation options for each scenario are outlined in Table 6.

Table 6. Congestion Scenarios and Mitigation Options

Scenario 1: Congestion Costs on a Transmission Path are Below $3 million/year – Breakeven Investment less than $20 million	**Manage Operations** ▪ Operations management – redispatch ▪ Dynamic Network Ratings ▪ Load Management of interruptible customers ▪ Remedial Action Schemes
Scenario 2: Congestion Costs on a Transmission Path in the Range of $3-25 million/year – Breakeven Investment of $20 to $150 million	**Mitigate Through Infrastructure Upgrades** ▪ Equipment Upgrades ▪ Transmission Path Upgrades
Scenario 3: Congestion Costs on a Transmission Path Exceed $25 million/year – Breakeven Investment Over $150 million	**Add New Infrastructure** ▪ New Transmission Lines ▪ New Generation

The menu of congestion mitigation options that are typically utilized by transmission owners and operators are summarized in Table 7.

Table 7. Congestion Mitigation Options Menu

Low level of annual congestion costs	Investigate simple upgrades to path – capital costs less than $20 million ▪ Upgrade wavetraps ▪ Add shunt capacitors ▪ Dynamic ratings ▪ Manage congestion through conventional dispatch techniques
Mid-range level of annual congestion costs	Investigate moderate grid upgrades – capital costs ranging $20-150 million ▪ Reconductoring key transmission lines (re-use existing towers and structures) ▪ Add static VAR compensators (SVCs) to improve dynamic performance ▪ Upgrade series capacitors
High levels of annual congestion costs	Evaluate grid expansion options – capital costs exceeding $150 million ▪ Construct new transmission lines ▪ Site generators inside bottlenecks

The menu approach to congestion mitigation appears to be easily applicable to inter- and intra-zonal congestion, where a single line or several lines in a single path can be identified as the source of the congestion costs being monitored. RMR costs are somewhat more challenging, as they relate to a general shortage of local generation to support specific loading and transmission contingency patterns. However, an extension of the present RMR study approach to identify the most feasible transmission upgrades that would reduce the need for a specific quantity of local generation requirement would allow application of the menu approach to RMR issues, and provide a clear cost-benefit assessment of further reinforcing the local transmission grid in order to avoid a premium price for operating local generation.

Table 8 below presents the annual cost of congestion as a function of congestion magnitude, price differential, and duration. As illustrated in the table, neither high congestion magnitude, high price differential, nor high duration alone can generate a high annual cost of congestion, but a combination of the three can generate significant congestion costs. When high congestion costs are present, the causes and annual repeatability of those costs must also be assessed. As noted earlier, for several of the key inter- and intra-zonal paths in the CA ISO grid, high congestion costs were caused by scheduled upgrade outages which, when completed, resulted in overall lower congestions costs, such as the Path 15 upgrades in 2005.

Table 8. Annual Cost of Congestion

MW	Duration @ 100 Hours			Duration @ 200 Hours			Duration @ 500 Hours			Duration @ 1,000 Hours		
	Price Differential ($/MWh)			Price Differential ($/MWh)			Price Differential ($/MWh)			Price Differential ($/MWh)		
	$10	$20	$50	$10	$20	$50	$10	$20	$50	$10	$20	$50
100	$0.1	$0.2	$0.5	$0.2	$0.4	$1.0	$0.5	$1.0	$2.5	$1.0	$2.0	$5.0
500	$0.5	$1.0	$2.5	$1.0	$2.0	$5.0	$2.5	$5.0	$12.5	$5.0	$10.0	$25.0
1,000	$1.0	$2.0	$5.0	$2.0	$4.0	$10.0	$5.0	$10.0	$25.0	$10.0	$20.0	$50.0
2,000	$2.0	$4.0	$10.0	$4.0	$8.0	$20.0	$10.0	$20.0	$50.0	$20.0	$40.0	$100.0

– At 15% annual carrying charge, $10 million in annual congestion costs translates to a cost effective capital investment of approximately $ 65 million

To be most effective, however, any screening approach to mitigating transmission congestion should be applied in a forward-looking manner, rather than monitoring congestion that is already taking place. This suggests that transmission planning studies should be expanded to include economic modeling of potential transmission congestion, so that facility upgrades and expansions can be planned and implemented to avoid the necessity of experiencing the market-disrupting transmission congestion.

The Department of Energy (DOE) National Electric Transmission Congestion Study, August 2006, reached the same conclusion. In that study, congestion was allocated into three classes:

1. **Critical Congestion Areas**

   – Critically important to remedy existing or growing congestion problems because of the current and/or projected effects of the congestion are severe.

   – Southern California included in this class.

2. **Congestion Areas of Concern**

   – Areas where large-scale congestion problem exists or may be emerging – requires more information and analysis.

   – In California—San Francisco Bay Area.

   – In WECC—Phoenix-Tucson area, and Seattle-Portland area.

3. **Conditional Congestion Areas**

– Some transmission congestion, but significant congestion would result if large amounts of new generation were to be developed without simultaneous development of associated transmission capacity.

– In WECC, Montana-Wyoming (coal and wind).

The DOE study conclusions focus on actual or expected congestion and highlight the need for long term planning to identify potential congestion paths and fix the problem through timely investments in new transmission facilities, in concert with planned generation development and forecast load changes.

On October 2, 2007, the Department of Energy designated the Southwest Area, which includes southern California, as one of the National Interest Electric Transmission Corridors (National Corridors). "These National Corridors serve as an important indication by the federal government that significant transmission constraint or congestion problems exist," Secretary of Energy Samuel W. Bodman said. "The goal is simple – to keep reliable supplies of electric energy flowing to all Americans. By designating these National Corridors, we are encouraging stakeholders in these regions to identify solutions and take prompt action."

3.3.5. Comparison with Other ISO's/RTO's

Data on congestion costs as a percent of total energy costs for different ISOs is presented in Table 9. During the 2004 to 2006 time period, these costs at different ISO/RTO ranged from a low of 1.2 % to a high of 9.4%.

Table 9. Comparison of ISO/RTO Congestion Costs

Congestion as % of Total Energy Cost			
ISO/RTO	**2004**	**2005**	**2006**
California ISO	8.2%	4.9%	5.4%
ERCOT	2.5%	1.7%	1.7%
ISO-NE	1.2%	2.3%	1.9%
Midwest ISO	NA	NA	2.1%
NYISO	6.5%	6.3%	6.0%
PJM	8.7%	9.4%	7.7%

In comparing the CA ISO's congestion cost, as a percent of total energy cost, with the other ISO/RTO's we see that the CA ISO appears to be in line with the NYISO, lower than PJM and much higher than ERCOT, ISO-NE and Midwest ISO. See Table 9. In comparing the actual $/MWH for congestion at the six ISO/RTOs we note that the CA ISO's costs appear to be trending down, but only the NYISO costs is higher in 2006. See Figure 3.

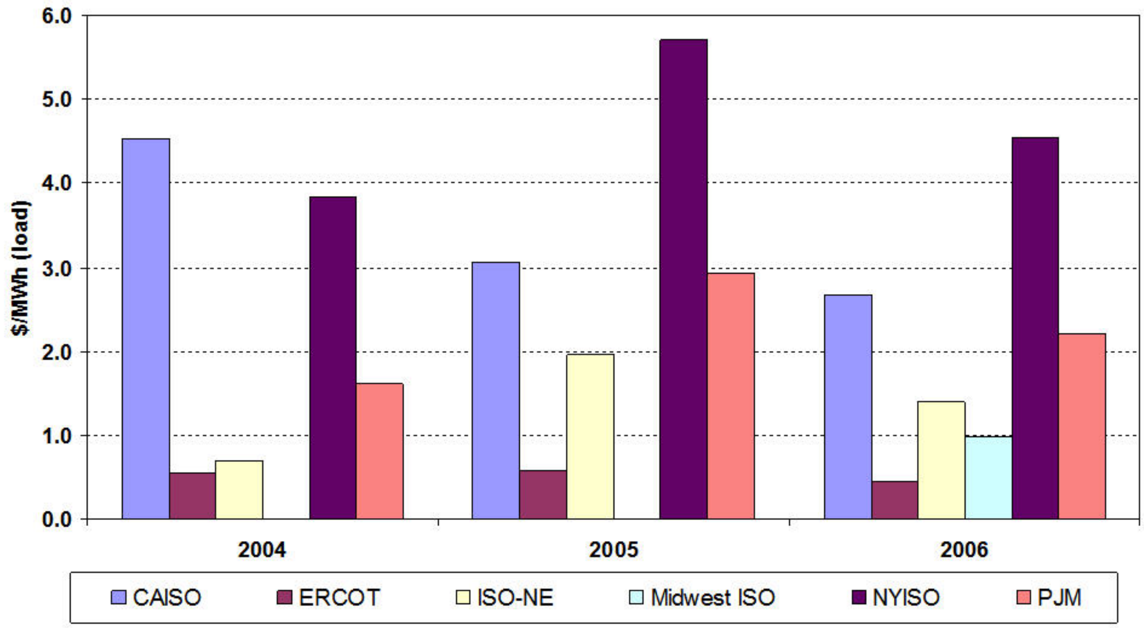

Figure 3. Cost of Congestion ($/MWh)

Based on both a comparison with other RTOs and ISOs, a reasonable level of transmission congestion costs in the CA ISO grid would be in the range of $250-650 million (in 2006 dollars). This would put congestion costs in the range of 2-5% of total energy costs.

PJM has proposed a market threshold approach to evaluate and understand transmission congestion. Their proposed approach assesses transmission congestion based on monthly congestion costs experienced, by voltage level, and establishes a timetable for analysis of mitigation options. The proposed approach is summarized below:

Market Thresholds—Monthly Congestion Level

- > 345 kV $100,000/month
- 345 kV – 100 kV $ 50,000/month
- < 100 kV $ 25,000/month

Process—within 60 days, post:

- Limit causing congestion
- Per unit cost estimate to remove limit
- Provide an indication of whether the cost-benefit justifies system upgrade based on:
    - Cost/benefit < 0.25 … Yes
    - Cost/benefit between 0.25 and 4 … Marginal
    - Cost/benefit > 4.0 … No

Process—within 1–year from date that cost-benefit info is posted:

- Refine original cost estimate.
- Evaluate secondary limits.
- Evaluate solutions to remedy multiple congestion events.
- Complete detailed benefit analysis including pact of load growth, future system upgrades and new generators.

A variant of the PJM threshold approach could be usefully applied to California. There are a variety of indices and metrics that could be used for such monitoring.

Appendix C presents summary of *Congestion Measures and Indices for Research* which could be used in California to determine when to take action to modify the grid to mitigate congestion. Additional research and investigation into these indices would be needed to determine which would be most appropriate for use on the California grid and market.

4.0 Key Policy Observations

There is a lot of anecdotal discussion that shapes policymakers' view of congestion. It is important to understand the magnitude, duration, economic impact, and persistence of congestion to understand whether it is good public policy to expend resources to eliminate congestion. Having a congestion-free grid is not economically justifiable. All congestion is not bad.

Some key policy observations to inform and guide decision-makers are presented below.

1. In the long term, congestion can only be avoided by planning and constructing sufficient transmission in advance to manage any remaining congestion costs to acceptable levels.

2. The current transmission planning/licensing process requires proof of congestion costs before new transmission lines are authorized.

    a. Congestion costs must rise high enough to warrant grid upgrades.

    b. Forecast congestion (or economic opportunities) as justification for new transmission is challenged during licensing, and all available options are exhaustively investigated as preferred over new transmission.

3. The current congestion monitoring mechanisms do not forecast future congestion or adequately measure current congestion.

4. Integration of intermittent resources to meet Renewable Portfolio Standard goals is likely to adversely impact congestion. Studies suggest $5.7 billion of transmission upgrades will be needed to integrate the new generation into the grid, but studies have not identified what levels of congestion will remain with this renewable generation expansion.

5. Transmission expansion is typically built to accommodate firm resources. Opportunity economy transactions contribute to congestion.

6. There are many forums investigating future transmission requirements, and identifying potential future areas of congestion, but no clear process and no accountable parties to act on the study conclusions.

7. New transmission lines take 5-8 years to license and construct. The licensing process must begin well in advance of any demonstrated congestion if excessive congestion costs are to be avoided.

8. Some level of congestion (uneconomic dispatch) is to be expected, and is economically acceptable (compared to cost of eliminating transmission constraint).

9. The CA ISO's congestion data understates the congestion costs.

10. Most of the CA ISO congestion cost results from excess schedules on the 230 kV and 115 kV portions of the grid, rather than on the 500 kV grid.
11. Approximately 55-60% of the annual cost of congestion is due to Reliability Must Run generation costs, which largely reflect the economics of operating generation in lieu of costly transmission expansion, which in the future will be addressed through the local utility procurement process.
12. The CA ISO transmission planning process is successfully identifying transmission lines and paths that can be economically upgraded.
13. The present 45-60 day lag time between incurring congestion and being billed for the cost aggravates cost effective management of congestion.
14. Management of day-to-day congestion could be achieved at lower overall cost with information transparency and better communication to the market participants and better coordination with the CA ISO.
15. Changes planned or implemented in California—Transmission investments, Resource Adequacy, Local reliability, Locational Marginal Prices, Market Redesign & Technology Upgrade (MRTU) can reasonably be expected to reduce congestion.
16. The implementation of Locational Marginal Prices pricing should provide Load Serving Entities (LSE's) sufficient price signals to achieve appropriate resource commitments. But care will need to be taken to ensure that LMP pricing does not overstate the significance of congestion. The LCR price premium under Locational Marginal Prices will be determined by the difference between the LMP within the constrained local zone and the system marginal energy price, both of which are dependent upon market response. Localized or unusual market conditions, such as adverse local hydro conditions or extreme local loads due to high or low temperatures may significantly affect the congestion costs.
17. There is inadequate coordination and information sharing regarding the hour-to-hour and day-to-day management of congestion between the CA ISO and the load serving entities to optimize planned transmission outages.
18. To reduce overall congestion in the CA ISO grid may require construction of addition transmission facilities. This will require collaboration among the CA ISO, transmission owners, and market participants. However, the CA ISO planning process has been largely unsuccessful in building and solidifying collaboration, instead leaving that role to the transmission owner. The process needs more partners and fewer commenters.

5.0 Research Conclusions

The purpose of this research study was to develop a better understanding of congestion – causes, impacts, mitigation options—which could provide a basis of information for decision-makers and to shape future research related to grid congestion. A summary of key research conclusions is presented below:

1. Congestion is an indication of a non-economic dispatch required to maintain grid operations within reliability limits.
2. Methodology for measuring congestion costs has been changing and continues to evolve.
3. CA ISO congestion cost data understates the amount of congestion that exists. It captures information related only to schedules attempted, as compared to the full economic potential for transactions. For instance, the economic congestion that presently exists and justifies the construction of the second Devers-Palo Verde 500 kV transmission line is largely unaccounted for in the CA ISO market congestion data. Absent similarly detailed studies of other major transmission paths, it is impossible to estimate how much existing congestion is not being identified.
4. Congestion costs vary due to market conditions
    a. Wet water year.
    b. High or low natural gas prices.
    c. Addition of a new generator in a region.
5. Congestion expenses are not classified clearly as to cause.
6. Normal conditions versus restrictions due to construction or other temporary outages.
7. Inter-zonal congestion costs are in reality revenues collected by CA ISO which are reimbursed to owners of firm transmission rights.
8. Inter-zonal congestion causes higher prices for all energy within the zone. This price impact is not captured in current congestion cost assessments.
9. Intra-zonal congestion costs are attributed to re-dispatch of generation (minimum load congestion costs to keep generators on, congestion re-dispatch of RMR units, and use of out-of-sequence dispatch to relieve congestion.) These costs are assigned to Participating Transmission Owners where the cost causation can be linked to re-dispatch costs incurred for intra-zonal congestion.
10. Reliability Must Run is the largest single component of congestion costs.
11. The Reliability Must Run congestion costs comprise a fixed cost component tied to the RMR contract and a pre-dispatch energy component resulting from day-ahead dispatch decision by CA ISO. These costs are also assigned to local Participating Transmission Owners.

12. Reliability Must Run costs represents the reliability aspect of congestion, while inter- and intra-zonal congestion represents the economic aspect of congestion. RMR costs (capacity and energy) are incurred in order to ensure adequate generation is available and can be dispatched on-line to serve the local load requirements. While RMR contracts limit the extent of the price premium that is associated with operating local generation, absent the RMR pre-dispatch of generation, high local marginal energy prices alone may not be sufficient to ensure adequate local generation dispatch to meet local load.
13. Without the construction of new local generation, Reliability Must Run costs can only be reduced by expanding the transmission capabilities into constrained local areas.
14. The South of Lugo and Palo Verde paths have accumulated congestion costs in excess of $10 million in both 2005 and 2006, (as illustrated in Table 5) which may be sufficient to warrant additional transmission upgrades or new transmission. Expansion of the Palo Verde path is already underway. The CA ISO and the PTOs should investigate the feasibility of transmission expansion to reduce the South of Lugo congestion costs.
15. Congestion across specific lines/paths is difficult to forecast
    a. Neither the generators nor the Load Serving Entities have clear visibility of congestion when it is occurring, which limits actions they could take to mitigate.
    b. Information systems are needed to inform all market participants of congestion when it is occurring.
    c. Neither the generators nor the Load Serving Entities have adequate information about planned equipment outages to adjust schedules to mitigate congestion.
16. Congestion can only be avoided by planning and constructing sufficient transmission in advance to manage any remaining congestion costs to acceptable levels.
17. Not all congestion is cost effective to eliminate.
18. Methodologies to allow forecasting of future congestion, and to facilitate planning and construction of needed new transmission facilities are needed
    a. Planning must be extended farther into the future.
    b. Planning must account for unexpected variations in key system operational variables, such as wet or dry hydro years, high or low natural gas prices, abnormal system loads (e.g., 1 in 10 load conditions), etc.
    c. New models and licensing approaches are needed to better address future needs.
19. Metrics are needed to identify and classify congestion costs as actionable, manageable, or monitor.

6.0 Project Recommendations

Although California's grid, like all other major grids in North America, has had its challenges with transmission congestion, for the most part California's investments in its transmission grid and interconnections have produced substantial reliability, economic, environmental, and fuel diversity benefits. California needs to continue its leadership in the WECC to develop strategic investments in its transmission grid that will mitigate congestion on both the existing and new transmission infrastructure. The project team has the following recommendations:

1. The CA ISO needs to continue its active participation on the WECC's Transmission Expansion Planning Policy Committee, which provides both oversight to the planning process and guidance in the analysis and modeling for WECC economic transmission expansion planning.
2. The CA ISO needs to provide a more open planning process as it relates to transmission congestion as well as information transparency. Most market participants interviewed felt they had little or no knowledge of congestion issues or access to meaningful data and information.
3. CA ISO should expedite activities to implement Locational Marginal Prices, so as to provide the Load Serving Entities with adequate price signals related to their generating resource commitment (startup and dispatch) during planned transmission outages.
4. As RMR is gradually phased out the CA ISO and Participating Transmission Owners will need to ensure that market participants and the CPUC have clear visibility of all options and related costs associated with meeting local capacity requirements. This would provide guidance for resource procurement activity in the impacted local areas.
5. The California utilities are not likely to be able to significantly reduce the need for RMR generation through the construction of local generation due to the challenges of siting new generation in metropolitan areas. In light of this, the CA ISO and the Participating Transmission Owners will need to actively seek solutions that will increase transmission into local areas so as to reduce Reliability Must Run costs going forward.
6. To ensure California's utilities can meet their Renewable Portfolio Standard goals, there is a need for the CA ISO and Participating Transmission Owners to define infrastructure requirements (in a phased approach) and associated costs to ensure deliverability of other renewable technologies that are located within the state
7. While the annual congestion costs for most of the inter- and intra-zonal transmission paths are below the threshold to warrant transmission upgrade, two paths, South of Lugo and Palo Verde, consistently showed sufficiently high congestion costs to warrant investigation for further upgrades. Southern California Edison's proposed development of the second Devers-Palo Verde 500 kV transmission line will address the Palo Verde path congestion. Investigation of additional upgrades of the South of Lugo path is warranted, especially since it is very likely that some future renewables energy will flow over this path.

8. The Energy Commission needs to continue its funding of research projects related to transmission congestion. The following are some identified areas:

Research Area	**Research Needed**
Data	Develop consistent definitions and appropriate metrics for monitoring and tracking
Classification of congestion costs	Classify congestion costs by cause (outages), transmission constraints, generation deficiency, etc, in order to appropriately determine which solutions would be most appropriate
Thresholds for action	• Determine appropriate thresholds by transmission level or path. • Assess the applicability of PJM Methodology or equivalent.
Mitigation options	• Catalog options. • Options should reflect the grids geographic diversity. • Correlate options with congestion cost thresholds. • Evaluate use of Load Management for congestion mitigation.
Congestion forecasting	• Short term forecasting and information transparency to enable market response for congestion mitigation. • Long term planning takes into account congestion – planning models need to be improved to address changing dispatch patterns and generation development.
Information transparency	CA ISO sharing of information including impact of outages on congestion patterns.

7.0 References

A summary of the reference documents used in the preparation of this report is included in the Bibliography.

8.0 Glossary

CA ISO	California Independent System Operator
COI	California Oregon Intertie
CPUC	California Public Utilities Commission
CRR	Congestion Revenue Rights
DPV2	Devers-Palo Verde 2 (transmission project)
DSM	Demand Side Management
FERC	Federal Energy Regulatory Commission
IPP	Independent Power Producer
ISO/RTO	Independent System Operator/Regional Transmission Operator
LDC	Local Distribution Company
LMP	Locational Marginal Prices
LSE	Load Serving Entity
MRTU	Market Redesign and Technology Upgrade
NERC	North American Electric Reliability Corporation
PTO	Participating Transmission Owner
RMR	Reliability Must Run
RPS	Renewable Portfolio Standard
SCIT	Southern California Import Transmission (system)
WECC	Western Electricity Coordinating Council

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Appendix A

Agencies/Entities Interviewed

CalEnergy – Independent Energy Producer

California Independent System Operator – Operations

California Independent System Operator – Transmission Planning

Imperial Irrigation District – Operations

Los Angeles Department of Water and Power – Operations

Pacific Gas & Electric – Transmission Planning

Powerex – Energy Marketer

Sacramento Municipal Utility District – Operations

San Diego Gas & Electric – Transmission Planning

Sempra – Independent Energy Producer

Southern California Edison – Energy Scheduling

Southern California Edison – Transmission Planning

Appendix B

Congestion Measures and Indices for Research

Cost of Congestion as percentage of total energy cost

Cost of Congestion across specific path vs. target cost level

- Investigate upgrades when congestion exceeds 5% of cost to upgrade, or specific dollar level

Reliability Congestion Index

- Actual Flow / OTC

Commercial Congestion (CC) Index

- CC = 1 – (ATC / OTC)
- CCI = percentage of time CC exceeded a value of 0.75 or 0.90
- CCI = 1 would indicate that a path is fully subscribed

Change in production cost

- Security constrained dispatch cost vs. unconstrained dispatch cost
- Indicates the societal cost of congestion

Change in congestion payments

- Congestion rent times load affected
- Equivalent to CA ISO inter-zonal congestion revenue and intra-zonal congestion management

Change in generation payments

- Cost guarantees paid to generators that are committed for reliability
- Equivalent to CA ISO RMR payments

Change in Load Payments

- Reflects the effect of all market segments that can change when transmission constraints are relieved

TLR-based measures including the number and degree of actions taken over a given time period

Frequency of curtailments

Duration of curtailments

Megawatts of curtailments

Energy of curtailments

Energy not served

Bulk Power Interruption Index (Capacity/Peak Load)

Bulk Power Energy Curtailment Index (Energy/Peak Load)

System Minutes (summation of MW not exchanged x minutes of duration)

Congestion rents