ASSESSING SYSTEM BENEFITS OF RENEWABLE TRUNKLINE TRANSMISSION PROJECTS

CONSULTANT DRAFT REPORT

Prepared For:
California Energy Commission

Prepared By:
Rumla, Inc.

DECEMBER 2006
CEC-100-2006-003-D

Prepared By:
Rumla, Inc.
Mohamed M. El-Gasseir, Ph.D.
Lafayette, CA
Contract No. 700-05-002
Work Authorization WA-1976

Prepared For:
California Energy Commission

Joseph Merrill
Contract Manager

Don Kondoleon
Project Manager

Robert Strand
Manager
ENGINEERING OFFICE

Terry O'Brien
Deputy Director
SYSTEMS ASSESSMENT AND FACILITIES SITING DIVISION

B.B Blevins
Executive Director

DISCLAIMER

This report was prepared as the result of work sponsored by the California Energy Commission. It does not necessarily represent the views of the Energy Commission, its employees, or the State of California. The Energy Commission, the State of California, its employees, contractors, and subcontractors make no warrant, express or implied, and assume no legal liability for the information in this report; nor does any party represent that the uses of this information will not infringe upon privately owned rights. This report has not been approved or disapproved by the California Energy Commission nor has the California Energy Commission passed upon the accuracy or adequacy of the information in this report.

ABSTRACT

The purpose and subject of this paper is to demonstrate the potential for significant traditional and strategic system benefits from trunkline transmission investments, using the proposed Third Segment of the Tehachapi wind project as a testing case.

KEYWORDS

Transmission, renewable resources, Renewables Portfolio Standard, renewable trunkline, wind, geothermal, system benefits, Southern California Edison, California ISO, California Energy Commission.

TABLE OF CONTENTS

BACKGROUND **1**
SYSTEM BENEFITS OF TRANSMISSION PROJECTS **2**
Determinants of California ISO Market Prices 2
How Will Renewables Moderate Market Prices Systemwide? 4
TECHNICAL APPROACH **6**
Basic Assumptions 7
Quantification Method 10
RESULTS **14**
The Case for Wind Resources 14
The Case for Trunkline Projects for Other Forms of Renewable Generation 15
CONCLUSIONS **15**

BACKGROUND

The California Independent System Operator (California ISO) is filing a petition before the Federal Energy Regulatory Commission (FERC) for a Declaratory Order establishing a Third Category of transmission investments eligible for rolled-in rate treatment under the California ISO Transmission Access Charge (TAC) tariff. This third category of transmission facilities is also referred to as trunkline transmission projects. The California ISO is filing the petition recognizing that renewable resources present a unique need for transmission facilities to interconnect multiple generators to the grid. Such facilities do not fit within the traditional categories of transmission projects that currently can be recommended and approved by the California ISO and placed under its operational control.[1] As noted by the California ISO, some major renewable resources are constrained to certain geographical areas with vast potential for renewable energy supply but limited nearby loads.[2] In addition, renewable generation development typically is added in relatively small increments over a long time with several developers involved.

The California Energy Commission has supported the creation of a third category of transmission projects to access remote renewable resources since it first recognized that transmission investment barriers posed a significant risk to California's ability to achieve its Renewable Portfolio Standard (RPS).[3] The Energy Commission identified the Tehachapi wind resource area and the Imperial Valley geothermal resource area as some of the most promising renewable resource locations in California where a third category of transmission projects could help address transmission interconnection issues.[4] Third category transmission facilities appear to be most applicable to remote regions of the state with relatively large concentrations of renewable resources. To assist the California ISO in identifying the potential need for future trunklines, the Energy Commission expects to undertake a more detailed assessment over the coming months of renewable resource areas in the state where trunkline transmission facilities may prove beneficial for meeting RPS goals.

The Energy Commission has recognized over the last few years that transmission facilities typically include strategic benefits that have not been quantified or included in traditional cost/benefit studies. The Energy Commission recommended developing methodologies for quantifying strategic benefits so that decision-makers can make more fully informed decisions about the expected present and future value of transmission investments.[5] This study represents a step forward in assessing strategic benefits of renewable trunkline transmission projects.

---

[1] California ISO White Paper, *Proposal to Remove Barriers to Efficient Transmission Investment*, September 21, 2006, p. 11.
[2] Ibid, p. 3
[3] Energy Commission, *2004 Integrated Energy Policy Report Update*, November 2004, p. 30.
[4] Ibid, p. 31.
[5] Ibid, p. 30.

The California ISO petition comes at the heels of a similar but unsuccessful application by Southern California Edison (SCE) to allow TAC recovery of the costs of a planned trunkline investment in the form of a third segment of the Tehachapi wind resources transmission infrastructure development project. Among the primary FERC arguments for rejecting the SCE petition is a lack of a demonstration that investing in the proposed generation transmission tie would result in system benefits above the gains expected to accrue to the sponsors of the project (SCE). Like the benefits to be gained by project sponsor(s), there can be traditional and strategic system benefits. The purpose and subject of this paper is to demonstrate the potential for significant traditional and strategic system benefits from trunkline transmission investments, using the proposed third segment of the Tehachapi wind project as a testing case.

SYSTEM BENEFITS OF TRANSMISSION PROJECTS

By definition, a trunkline transmission project will be of interest to investors if there are reasonable expectations that undertaking it would facilitate the development of a *considerable* resource base of renewable generation. As explained further in this section, injecting a large amount of renewable energy in a centralized market of the type operated by the California ISO will moderate wholesale electricity prices in the California ISO control area and to a lesser extent in the rest of the Western Electricity Coordinating Council (WECC) service areas. The *system* benefits of trunkline transmission projects for renewable resources can then be defined as the savings that consumers in the California ISO and the WECC should expect from the aforementioned moderation of market prices. It should be emphasized that:

- Such system benefits are beyond the economic value that the sponsors of the trunkline transmission projects expected to receive; and

- The system benefits will be realized whenever the amount of renewable generation entering a market is large enough to reduce wholesale electricity prices for most if not all market participants.

Determinants of California ISO Market Prices

Under the recently approved Market Redesign and Technology Update (MRTU) tariff, the California ISO plans to implement in late 2007 a nodal pricing platform for scheduling and settling all transactions involving the grid it operates. The new regime will generate nodal (i.e., bus-specific) locational marginal prices (LMPs) for the California ISO day-ahead (DA) and real time (RT) markets. The California ISO expects to schedule and settle at least 95 percent of its loads and resources in the DA market with the remainder, including deviations due to forecasting errors, outages and other uncontrollable (unscheduled) operational changes, to be

settled at RT market prices.[6] To minimize price disparities between the DA and RT Markets, the California ISO intends to implement a convergence bidding mechanism to enable buyers and sellers of generation to hedge their transactions across the two markets. In the end, successful implementation of the MRTU should produce DA and RT nodal price patterns that are reflective of the targeted size of each market and not too different from each other.

Each nodal price will consist of three elements: an energy-commodity component, an adjustment for marginal losses, and possibly a congestion charge. The marginal losses contribution is relatively modest and highly localized. The congestion charge can be significant but is both strongly localized and sporadic. It is expected that the energy commodity component will be, by far, the principal determinant of nodal prices. In a well-functioning market, the energy value should account for at least 90 percent of the average nodal price.

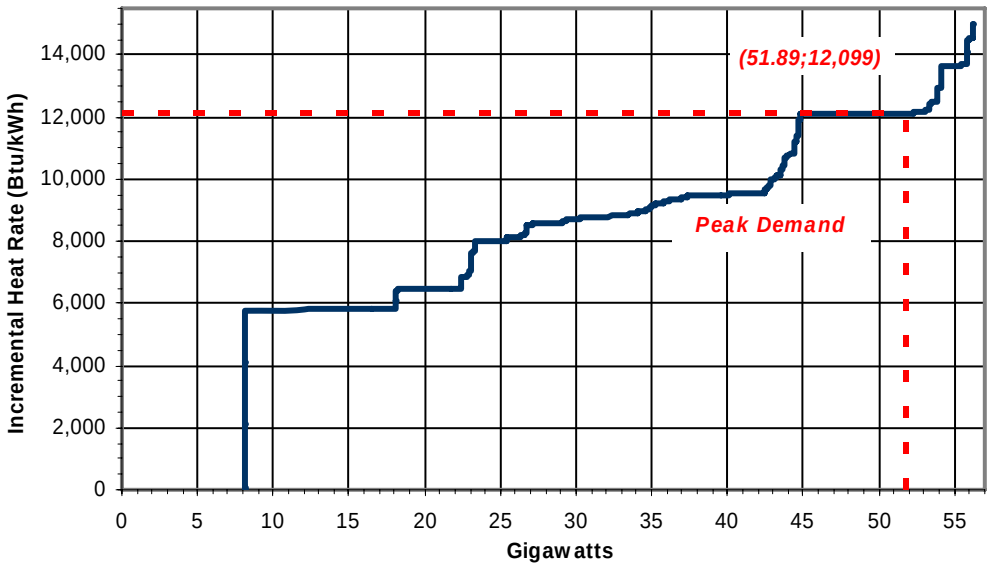
In a centralized market of the type operated by the California ISO, a single energy commodity value is used for determining all nodal prices at any particular point in time. This common component of the LMPs, defined as the per-unit commodity cost of the energy needed to meet an equal unit of the California ISO's system load using the lowest-priced available resource at the applicable point of time, can be considered as the market clearing price for electric energy in the California ISO control area for that same point in time.

Determining the market-clearing price for the energy commodity can be accomplished by stacking the available resources in order of increasing price or cost of supply until the cumulative available supply equals the sum of all loads in the control area plus exports at the point of time of interest. This procedure is illustrated by Exhibit I where marginal (incremental) heat rates are used as proxies for bid prices to supply the available blocks of energy.[7] This illustration shows that the highest increment of the California ISO 2012 peak load would be served by a generator at a marginal heat rate of 12,099 Btu/kWh. If one assumes that the California ISO operates perfectly competitive markets and that the cost of natural gas for the marginal generator is $10/MMBtu, the market clearing price for the energy commodity would be approximately $121/MWh.

[6] The 95-percent scheduling target has been the subject of considerable debate in California and at the FERC during the ongoing MRTU proceedings.

[7] In a situation of perfect competition a seller would bid a price equal to the sum of: (i) its incremental heat rate times the cost of fuel, and (ii) its variable operation and maintenance expenses.

Exhibit I: 2012 Load-Resources Balance at Peak Demand Conditions for California ISO Control Area



How Will Renewables Moderate Market Prices Systemwide?

Renewable resources will deliver energy into the California ISO markets in two ways. In the majority of cases, the produced generation will be purchased from developers under long-term contracts. In some situations, renewable facilities may sell energy directly into the California ISO DA and RT markets (for example, to dispose of surplus generation not covered by a purchase contract). In the first instance, long-term buyers will be keen on scheduling in the California ISO markets every MW that they have already purchased from the generating facilities. This behavior, also known as self-scheduling, will be accomplished by bidding into the relevant market as price-takers.[8] In the second instance, resource developers will schedule uncontracted-for renewable energy in the California ISO markets. In this case too, it is in the interest of the generators to be price-takers to ensure the sale of the entire output of their facilities.[9] In other words, renewable generation should be expected to be self-scheduled as price-taking resources irrespective of their ownership status.[10]

In the process of determining the resources to be used to meet electricity demand and associated patterns of energy commodity and nodal prices, self-scheduled generation will be given dispatch priority as price takers. This means that these resources will be considered to be

[8] A price-taker is a seller who is willing to accept any price the California ISO assigns to its point(s) of delivery.

[9] Operating or production costs are normally much lower than the opportunity costs of foregoing recovery of the capital investment and associated returns.

[10] The exception is a situation of persistent negative nodal prices. However, one would not expect rational investors to locate their investments in areas of potential negative prices.

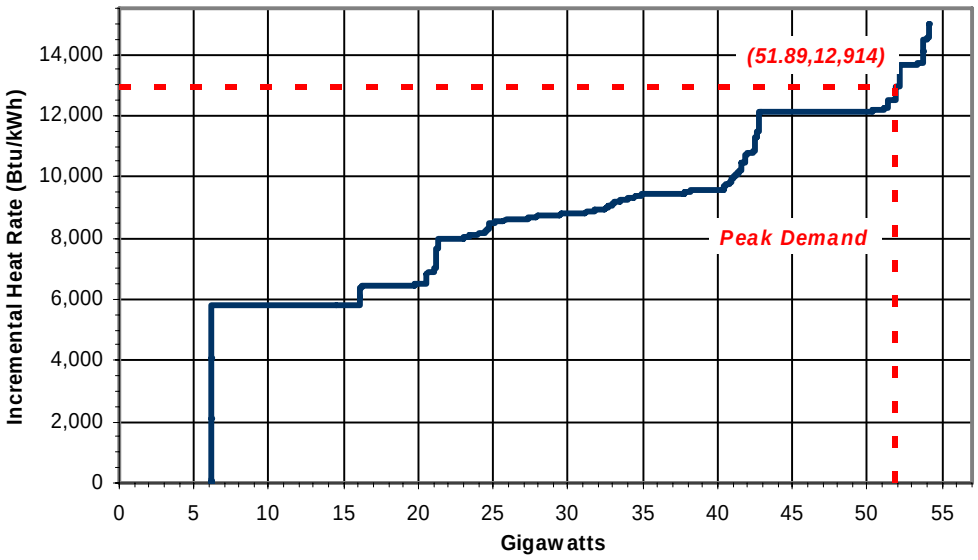
bidding a price no greater than the lowest offered price for any resource available for the dispatch period of interest. Mathematically, this situation can be symbolized by a block of zero-priced energy since it is not likely that any rational seller would offer power at negative prices (that is, no supplier would want to pay a buyer to take its product). Pictorially, self-scheduled generation, including renewable energy, would be part of the zero-priced region of the supply curve shown in Exhibit I (namely, the first 8,125 MW of the available resources).

Introducing new increments of renewable generation by developing additional resources will increase the market share of the price-takers. In Exhibit I, this takes the form of a widening of the zero-priced block of self-scheduled generation by displacing to the right the incremental supply curve. The movement of the curve to the right will cause it to intersect the demand (vertical) line at a lower marginal (market clearing) heat rate. The end result of expanding the renewable resources base is a reduction in energy commodity prices and in nodal prices in general. This can be illustrated by constructing, as in Exhibit II, the California ISO supply portfolio for 2012 without the wind generation resources that are expected to be developed between 2006 and 2012 and comparing the resultant energy commodity market clearing heat rate with the one obtained in Exhibit I:

Market clearing incremental heat rates at 2012 peak demand (Btu/kWh)	
Without post-2006 wind investments (Exhibit II)	12,914
With post-2006 wind investments (Exhibit I)	12,099
Incremental heat-rate reduction due to wind investments	815
Market clearing energy commodity cost assuming a gas price of $10/MMBtu	
Without post-2006 wind investments ($/MWh)	129
With post-2006 wind investments ($/MWh)	121
Potential energy cost and LMP reductions ($/MWh)	8

Since the entire California ISO load (of 51,890 MWs) will be settled using the same cost of the energy commodity component of the LMPs, the potential savings from the downward price-pressures due to wind generation could amount to $415,120 per hour at 2012 peak demand conditions. It should be noted that because peak demand prevails only for short times and since the timing of high wind-productivity may not coincide with high-demand periods, the expected hourly savings will be lower.

Exhibit II: 2012 Load-Resources Balance at Peak Demand Conditions for California ISO Control Area Without Added Wind



TECHNICAL APPROACH

Accurate estimation of the system benefits of trunkline transmission projects requires:

- Detailed information on expected load and renewable generation profiles, generation availability and performance characteristics, and transmission loading constraints;

- A statistically valid understanding of how system loads correlate with the availability of the renewable generation to be developed; and

- The application of a sophisticated security-constrained economic dispatch (SCED) model.

At present, this level of accuracy is not feasible. First, there is a lack of statistically credible information that could enable accurate correlation between the principal (control) parameters involved. This problem is especially severe for transmission investments supporting wind generation development. Available wind frequency records are too limited to allow informative correlation with service-area load variations. Second, the current generation of SCED tools is not capable of conducting practicable simulations of grid operations while accounting for the stochastic nature of customers' loads and intermittent resources. Third, using a SCED involves considerable data preparation and management that often become the center of debate and contentious proceedings, diverting attention from the main subject: that there are potentially

significant system benefits to be gained from developing trunkline transmission projects for renewable resources.[11]

The problems just described have been avoided by devising a simpler approach that focuses on establishing minimal estimates of the system benefits of trunkline transmission investments. Focusing on estimating the minimal achievable benefit enables one to make a number of key simplifying assumptions that can render running a SCED unnecessary and engaging in the structuring of contentious scenarios avoidable.[12] The approach used involves:

- Adopting specific assumptions designed to err on the side of under-estimating rather than over-estimating the value of trunkline transmission projects; and
- Constructing a simplified spreadsheet representation of supply-demand equilibria for the California ISO control area.

Compared to using a SCED tool, the simplified approach is far less demanding with respect to input data requirements and information management. As shown in this paper, it also offers much greater transparency and is easier to understand.

Basic Assumptions

The combined effect of the 15 assumptions described below is overwhelmingly in the direction of underestimating the system benefits of trunkline transmission projects for facilitating renewable energy development.

Perfect Competition

Under this assumption, sellers will bid their generation at their marginal cost of production. This simplification eliminates the need to speculate about the mark-ups that would have to be included in simulated bid prices. Because the resultant energy offers will cost less, assuming perfect competition will produce lower estimates of the system benefits of trunkline transmission projects.

No Variable O&M Expenses

The marginal cost of electricity production consists of two components: fuel costs and variable operations and maintenance expenses. Dropping the latter avoids the need to track individual plant operating cost data. The effect of this assumption is a reduction of bid prices (to levels even less than those associated with perfect competition) and therefore a lowering of the estimates of system benefits.

---

[11] SCED modeling efforts often get mired in protracted challenges and debates over the commercial model used, the computational techniques it relies on, the assumptions made and input data availability.

[12] The SCED method can produce more accurate results by accounting for system constraints and generating unit limitations and is more suited for planning studies and detailed project assessments.

No Emissions Control Management Costs

The costs of procuring pollution reduction credits are ignored. The effect of this simplification is an additional reduction of the bid prices of certain fossil-fueled units and an overall underestimation of the value of the system benefits of trunkline transmission projects.

No Allowance for Scheduled Maintenance

Incorporating scheduled maintenance will increase the frequency of running inefficient generating units. Excluding it will lower the system benefits estimates.

No Accounting for Forced Outages

This assumption will considerably simplify the representation of the load-resources balancing process. As in the case of scheduled maintenance, it will reduce the system benefits estimate since plant outages increase the need to run expensive units.

No Transmission Congestion

Accounting for potential transmission congestion will lead to more accurate albeit higher estimates of the costs of wholesale electricity for consumers. Ignoring it simplifies the assessment process, but the resultant error is on the side of underestimating the system benefits of trunkline transmission projects.

No Marginal Losses Charges

Dismissing this component of nodal prices greatly simplifies the computations. Including marginal losses tends to increase the overall costs of wholesale electricity. Excluding them is likely to produce lower estimates of the system benefits of trunkline transmission projects.

Efficient Nonrenewable Generators Will Not Act as Price Takers

Most efficient (new) nonrenewable generators should be supplying power under long-term, take-or-pay contracts and are, therefore, likely to be self-scheduling their output energy in the California ISO markets. Accounting for this behavior reduces the probability of dispatching the least efficient units. Ignoring it eliminates the need to track contract provisions and tends to reduce the estimated value of system benefits.

Reliability-Must-Run (RMR) Units Are Not Price Takers

There is a minimum amount of RMR generation that is expected to be dispatched at all times, barring the incidence of scheduled and forced outages. Nevertheless, it is assumed that no RMR

generation will be self-scheduled. The reasons for using this assumption are the same as in the previous case. However, the effects on the estimation of system benefits in 2012 are minimal.[13]

No Accounting for Imports into the California ISO Control Area

To be accurate, take-or-pay imports should be treated as self-scheduled contracts. The effects of ignoring them are similar to those discussed under "Efficient Nonrenewable Generators Will Not Act as Price Takers." However, such imports meet a small portion of California ISO's loads. And as discussed below, excluding exports will counteract the effects of ignoring the imports. This view also applies to dispatchable imports that are also excluded. The costs of the generation brought in during peak-demand hours tend to track the prices of California ISO's peakers. (On-peak imports and local thermal peaking facilities will be indistinguishable from a pricing perspective.) In summary, the net effect of ignoring imports is probably a minor underestimation of system benefits.

Exports Can Be Ignored

Exports add to California ISO's load service obligations. Ignoring them will lead to undervaluation of system benefits. The effects of this assumption counteract the implications of excluding the role of imports.

Optimization of Hydro Resources

Hydro generation owners may reserve some stored energy to bid as peak-shaving units during periods of high prices. Simulating such behavior involves venturing into hydro-thermal optimization in quasi-competitive markets, a subject that is still under intense academic research. Since bid prices for hydro peaking generators are likely to track their thermal counterparts, the error of ignoring strategic bidding by few owners is probably not significant. To avoid the pitfalls of complex dispatch optimization, it is assumed that hydro generation will be evenly available year-round as price-taking resources. In Exhibit I, this assumption amounts to displacing the supply curve to the right, leading to lower market-clearing incremental heat-rates (prices) for the energy commodity. Hence, averaging the availability of hydro generation as a year-round, price-taking resource base will lead to lower estimates of the system benefits of trunkline transmission investments.

No Accounting for Load Management or Energy Conservation Investments

Load management and energy conservation programs reduce system loads, leading to lower market prices, and could take away from the value of the system benefits of renewable energy investments. Ignoring load management and energy conservation programs could inflate the

[13] RMR contracts are being phased out. Also, the effects of accounting for the lower RMR blocks should be largely confined to the long flat regions of the staircase supply curve where the effects on system benefits are likely to be minimal.

value of system benefits. However, this error is probably dwarfed by the effects of assuming 100 percent availability of all generating units. (See "No Allowance for Scheduled Maintenance" and "No Accounting for Forced Outages.")

A Single, Base-Case Scenario Representation of System Loads

Proper representation of system loads requires adequate consideration of its stochastic nature. This level of analysis is not tenable even for detailed SCED-type assessments. Using a base-case forecast backed with alternate scenarios is a common practice. If load growth turns out to be lower than expected, adopting a base-case scenario will overestimate system benefits. But such an approach amounts to substituting risk-taking behavior for a risk-averse strategy.

The Marginal Fuel Is Natural Gas

Historically, the fuel on the margin (the energy source serving the last increment of load) year-round in California has been essentially natural gas.[14] This has been the case since the 1970s, and there are no prospects for a change in the near term. Equally important is the fact that gas prices set the pace for the cost of wholesale electricity in the California ISO markets.

Quantification Method

The focus of this paper is on assessing the potential role of trunkline transmission projects for renewable resources in moderating wholesale electricity prices systemwide. It was argued that such role can be evaluated without the risk of overstating the case by limiting the assessment to the expected impacts on the costs of the energy commodity component of future California ISO nodal prices. It was also established that one could estimate this type of system benefits in a relatively conservative and transparent manner using a set of simplifying assumptions.

Mathematical Formulation

Given the above considerations, the value of energy cost moderation (VECM) as a system benefit for a trunkline transmission project can be stated as:

$$VECM = EC0RTP - ECWRTP \qquad (1)$$

Where

EC0RTP = Energy Cost without the Trunkline Transmission Project

ECWRTP = Energy Cost with the Trunkline Transmission Project

Equation (1) can be translated into the following expression:

$$VECM = \sum [\, CLh \times (IHR0h - IHRTh) \times GP \,] \qquad (2)$$

[14] There are a few hours where the unit on the margin may not be gas fired. But even then, the price paid to the marginal generator is very likely to be heavily influenced by the prices bid by the competing gas units.

Where

CLh = California ISO Load at Hour h

IHR0h = System Incremental Heat Rate for Hour h without the transmission project

IHRTh = System Incremental Heat Rate for Hour h with the transmission project

GP = Gas Price

The Time Factor

Normally, an economic assessment of a project is carried out for its expected life. Because this paper is concerned with only demonstrating the potential significance of system benefits, the evaluation has been confined to a single year. The year selected for the assessment is 2012 since – as discussed below – it is likely to be the first year of operation after the expiration of the bulk of the long-term purchase power contracts the load-serving entities (LSEs) are currently using to meet their loads. The summation sign in Equation (2) is over all hours of 2012.

The Load Factor

According to Equation (2), the entire California ISO load will benefit from a reduction in the cost of the energy commodity component of the LMPs. This proposition rests on three arguments:

- Long-term prices for wholesale power are primarily determined by market participants' expectations about the outlook for spot prices in the long run. In California, the spot prices of interest are California ISO's LMPs since approximately three quarters of the state's loads are served by LSE members of the California ISO. In fact, this is also a safe assumption for the WECC as a whole considering California's share of the region's total load is around 40 percent.[15]

- Long-term trends of California ISO's future LMPs will affect the determination of contract prices in two ways. First, both buyers and sellers will be relying on forecasts of LMPs to reach agreeable pricing terms. Second, in some cases, the parties may even agree to index contract prices with California ISO's nodal prices or a proxy thereof.

- It is expected that the vast majority of the state contracts will have to be replaced by 2012. And considering most of the balance of the LSEs purchase power agreements do not exceed five years in duration, it can be assumed that there will be a near total turnover of all contracts covering the loads served by the California ISO's' LSEs.

[15] Skeptics need only examine the extent to which the California market meltdown of 2000-2001 spread beyond its borders. However, the analysis presented in this paper has been confined to the California ISO control area.

Reduction of the Systemwide Incremental Heat-Rates

Most generating facilities are modeled as sets of energy blocks, with each block characterized by an incremental heat rate signifying the rate of fuel burn for each kilowatt-hour of produced electricity from that block of generating capacity. In this simplified model, the blocks of all the California ISO generating units were stacked into a portfolio of available supply arranged in order of increasing incremental heat rates without regard to whether successive blocks belonged to the same unit. The constructed portfolio is the California ISO supply curve for 2012 as demonstrated by the stairstep line in Exhibit I.

The point of intersection of every vertical line representing a level of the California ISO total load with the staircase supply curve determines the system's incremental heat rate for that level of demand. That is to say it is possible to definitively determine for every load point a specific systemwide incremental heat rate, represented by IHR0h in Equation (2). It should be noted that IHR0h reflects a California ISO grid without the trunkline transmission investment (and the associated renewable energy) to be assessed. Multiplying the systemwide incremental heat rate by the price of gas, GP, yields the marginal cost of the energy commodity component of the LMPs for all the nodal pricing points of the California ISO.

Adding a block of self-scheduled (price taking) renewable energy shifts the staircase supply curve in Exhibit II to the right by a horizontal displacement equal to the number of MWs introduced into the portfolio. The resultant shift creates a new point of intersection with the vertical line representing the California ISO load. This new point, symbolized as IHRTh in Equation (2), determines the system incremental heat rate and the associated California ISO marginal cost of energy in the presence of the renewable energy block delivered by the trunkline transmission investment of interest. The difference between IHR0h and IHRTh equals the decrease in the systemwide incremental heat rate resulting from the availability of renewable energy.

Gas Prices

Spot (wholesale) gas prices can change daily. In practice, generators procure their fuel needs on a long-term basis. Therefore, the price uncertainties of significance involve seasonal changes and long-run trends. The cyclic nature of seasonal price movements cancels out some of the volatilities over the year. The dominant source of risk for planners is the uncertainties in the long run. In this simplified assessment of the system benefits of trunkline transmission projects, a single annualized price of gas, GP, is used. The value used in this study is a recently published price of an 18-month NYMEX Natural Gas Futures strip escalated at 4 percent per year to 2012.[16] In Equation (2), GP can be easily changed to evaluate several scenarios (or sensitivity cases). Note that one can easily introduce a scenario representing a gas-price reduction resulting from a significant fuel displacement caused by a large renewable energy contribution from the trunkline transmission project of interest.

[16] The estimate used in this study is $9.138 per MMBtu as posted by *Enerfax Daily*, Section 8, December 15, 2006.

Computational Algorithm

To evaluate system benefits, the following procedure was used:

1. A 2012 hourly load forecast for the California ISO control area was obtained from a Rumla database that was also used for the Intermittency Analysis Project (IAP).

2. The 2012 hourly load forecast was transformed into a load probability distribution for the California ISO control area.

3. Block size and incremental heat rate data was obtained for all generation serving California ISO LSE loads from the IAP database.

4. The generation database was processed into a staircase supply curve by;

   - Filtering out all units retired before 2012, plants installed after 2012, and renewable units added after 2006;

   - Assigning zero values to the incremental heat rates of every block of all the renewable and hydro units remaining in the database;

   - Sorting out the blocks of all units and ordering them from the lowest incremental heat rate to the highest; and

   - Constructing a cumulative supply curve in order of increasing incremental heat rates.

5. The systemwide incremental heat rate in the absence of post-2006 renewable investments was determined for all levels of California ISO's loads in 2012.

6. Steps 4 and 5 were repeated after injecting 100 and 500 MWs of self-scheduled renewable generation into the 2012 supply portfolio to produce reduced systemwide incremental heat rates. The chosen quantities of new renewable energy represent two levels of generation availability as explained in the section discussing the results of this assessment.

7. The value of the energy cost moderation system benefit was estimated using the following variation on Equation (2):

$$VECM = GP \times \sum [\, pi \times CLi \times (IHR0i - IHRTi) \,] \qquad (2)$$

   Where

   pi = the probability of load attaining a load level CLi

   and the other terms are as explained previously.

RESULTS

Table 1 presents estimates of potential system benefits of a trunkline investment modeled after Segment 3 of the Antelope Transmission Projects proposed by Southern California Edison in its March 23, 2005 petition for a declaratory order. Specifically, the test case adopted for this work represents an Antelope-to-Tehachapi radial transmission investment consisting of two substations and high-voltage lines designed to access 3,500 MWs of wind generation.[17] According to California ISO planners, the total cost of these facilities is approximately $450 million.[18]

Table 1: Study Results Using Antelope Transmission Projects Segment 3 as a Test Case

Minimum Sustainable Generation (MWs)	Availability Of the Minimum Sustainable Generation*	Electricity-Price Moderation System Benefits	
		Annual Savings	Imputed Cost of Transmission
		(Million $ per Year)	(Million $)
100	2.9%	47	266
300	8.6%	135	772
500	14.3%	228	1302
700	20.0%	322	1842
900	25.7%	417	2385

The Case for Wind Resources

As indicated by Table 1, system benefits were evaluated for five levels of minimum sustainable output ranging from 100 MWs to 900 MWs. (A 100-MWs level means that at least 2.9 percent of the installed 3,500 MWs of wind turbines would be producing energy two hours a day year-round.) Clearly, the low values are more likely to be realistic benchmarks for the minimum amount of generation that can be maintained under all network-loading conditions.

A close examination of the information presented in Table 1 reveals the following:

- California ISO customers should benefit from systemwide reduction of electricity commodity prices at a rate of at least $47 million per year assuming continuous wind energy availability from only 2.9 percent of a 3,500 MWs of installed capacity. Such savings can

[17] The 3,500 MWs estimate of the incremental wind-generation contribution of the Segment 3 Project was obtained from California ISO staff through personal communication on October 23, 2006.
[18] Ibid, October 23, 2006.

justify at least $266 million (or nearly 60 percent) of the $450 million of estimated cost of a trunkline version Segment 3.[19] For comparison purposes, the annualized cost of radial Segment 3 would be $79 million per year.

- Assuming the Tehachapi farms are capable of sustaining 300 MWs of 24x7 generation output (or a minimum availability of 8.6 percent) increases the value of potential systemwide moderation of electricity commodity prices to at least $135 million per year. Such level of savings is more than needed to fully justify the trunkline investment on the basis of the system benefits alone.

The Case for Trunkline Projects for Other Forms of Renewable Generation

The value of the system benefits of trunkline projects for other forms of renewable resources such as solar and geothermal generating facilities can be also gauged from the results of Table 1 by focusing on the higher levels of the minimum sustainable generation parameter. For example, the 700-MWs row indicates that the electricity-prices moderation savings can alone justify a transmission trunkline costing at least $1.8 billion. It should be noted that the assumed 700 MWs corresponds to a 20-percent minimum generation availability that represents the performance of solar thermal-generation farms.[20] Shifting to the 900-MW row of Table 1, one can get an indication of how strong the case can be for non-intermittent resources such as geothermal fields. As the results show, the electricity-price moderation benefits can justify a trunkline investment of at least $2.4 billion. This outcome is based on minimum-generation availability much lower than what is to be expected from modern geothermal plants.

CONCLUSIONS

The results of the study described in this report indicate the following:

1. Trunkline transmission projects can provide system benefits above the economic values that their proponents expect to capture for themselves;

2. Because of the centralized nature of the California ISO markets and their relative size in California and the WECC Region as a whole, all ratepayers stand to gain from the availability of the identified system benefits; and

3. The identified benefits can be large enough to justify rate-based investment in trunkline projects.

[19] Assuming a fixed charge rate of 17.5 percent per year.

[20] Simulating solar investments lacking generation-storage capability requires special handling to accommodate the diurnal cycling of energy production. However, given that the output correlates with the heavier loading hours of daytime, the results indicated in Table 1 are likely to underestimate the system benefits of concern.