**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

In the Matter of the Application of The Nevada Hydro Company for a Certificate of Public Convenience and Necessity for the Talega-Escondido/Valley-Serrano 500 kV Interconnect.	)))))	Application 10-07-001 (Filed July 6, 2010)

Direct Testimony of Christine Vangelatos

on behalf of

The Nevada Hydro Company

November 30, 2010

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on behalf of The Nevada Hydro Company

Subject Matter Index

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<u>Introduction</u>

Q. Please state your name, title, and business address.

A. My name is Christine Vangelatos, and I am the Director of Analytics for ZGlobal, Inc. an engineering and energy services consulting company located at 604 Sutter Street, Suite 250 in Folsom, CA 95630.

Q. Please describe your employment and other relevant experience.

A. I joined ZGlobal Inc. in November 2006 as its Director of Settlements and have been in my current role as the Director of Analytics for the past 2 years. With ZGlobal, I consult with multiple clients providing expertise and analysis in California nodal pricing, market design and settlements, including providing results analysis of ZGlobal's production cost economic model. I am one of the key engineers responsible for running computer simulations that forecast energy dispatch and calculate production costs for the California ISO (CAISO) grid. On a daily basis we utilize these forecasts to provide 7-day outlooks on energy and locational marginal prices for multiple CAISO market participants. The forecast model is also used for longer term planning studies to assess the economic impact of our clients' generation or transmission projects. Prior to ZGlobal, I worked at two other companies, the CAISO and Pacific Gas & Electric (PG&E) respectively. I was a start-up team member and held various lead engineering and management roles in the Market Operations, Market Quality and Settlements departments at the CAISO between July 1997 and October 2006. In this capacity, I managed the day-to-day operations, staff and had overall responsibility for design and implementation of business processes and charge equation configuration for the CAISO's settlement and billing systems such that they supported CAISO's market design and settlement operations objectives and systems, tariff and product development related to the California markets. I worked at PG&E between 1992 and 1997 where my last position was Lead Power Systems Engineer in the System Operations department and served as a PG&E representative on various industry workgroups and forums. I received my Bachelor of Science in Electrical Engineering with a Power Concentration from California Polytechnic State University, San Luis Obispo in 1992 and a Master of Science in Computer Information Systems Management from the University of Phoenix in 2002. My resume is included in Exhibit 1 to this testimony.

Q. On whose behalf are you submitting this testimony?

A. I am submitting testimony on behalf of the Nevada Hydro Company (TNHC).

Q. What is the purpose of your testimony?

A. TNHC has retained ZGlobal to conduct an economic benefit-cost analysis for the Talega-Escondido / Valley-Serrano 500kv interconnect ("TE/VS") project. I will be providing testimony with regards to the production cost model and assumptions used by ZGlobal to quantify the consumer and Independently Owned Utility (IOU) benefits of TE/VS including an analysis of the impact it has to interconnect the Lake Elsinore Advanced Pump Storage ("LEAPS") project.

The benefit categories of TE/VS from California ratepayers' perspective are as follows:

A. Reduction in energy cost (including losses) or "Consumers Benefits"

B. Net "Societal Benefits" which add the reduction in congestion cost and the increase to producer surplus to the Consumer Benefits

C. Reduction in capacity payments related to the Local Capacity Requirement or Reliability Benefits

D. Reduction in RPS costs

TE/VS benefits related to items A and B are addressed in my testimony. Benefit categories C and D are addressed in Dr. Bergman's testimony.

Our analysis additionally quantifies the benefits TE/VS has to interconnect the LEAPS project. We quantify those benefits from California ratepayers' perspective as follows:

A. Consumers Benefits

B. Net Societal Benefits

C. Reduction in Ancillary Service cost

TE/VS benefits to interconnect LEAPS related to items A and B are addressed in this testimony. Benefit category C is addressed in Dr. Bergman's testimony.

Q. Have you previously performed similar analysis?

A. Yes. I have performed similar analysis with results filed with FERC and in one instance the results were used to obtain rate approval from FERC. Specifically, I performed analysis for the Green Energy Express, a proposed 500kv line in southern California, and the TransBay cable. The TransBay cable economic and reliability assessment was the basis in which FERC used to approved the rate for the TransBay project that is scheduled to go in commercial operation on 11/23/2010.

Q. How is your testimony organized?

A. My testimony is organized in three parts: (1) Description of the modeling approach and input assumptions using PLEXOS, (2) Summary of the Consumer and net Societal

Benefits calculated for TE/VS and (3) Summary of the Consumer and net Societal Benefits for TE/VS to interconnect the Lake Elsinore Advanced Pump Storage ("LEAPS").

I. Modeling Approach and Input Assumptions Using PLEXOS

Q. Does your analysis utilize the CAISO's Transmission Economic Assessment Methodology ("TEAM") approach?

A. Yes, my analysis and the use of PLEXOS for Power Systems for the production cost simulation are in accordance with the CAISO's Transmission Economic Assessment Methodology ("TEAM") approach which was adopted by the CPUC for use in economic evaluations of proposed transmission projects in Commission certificate of public convenience and necessity (CPCN) proceedings[1]

Q. Please elaborate on the definition for the Consumer and net Societal Benefits as it relates to the TEAM approach.

A. In my analysis, the TEAM methodology is used to calculate Consumer Benefits. The objective for the Consumer Benefit calculation is to evaluate how consumer costs of energy change with the addition of a project. The reduction in energy cost is mainly driven by the differentials in nodal prices under locational marginal pricing (LMP). The LMP price differentials are attributable to differences in marginal fuel costs (captured as the difference in the marginal cost of energy) and marginal line losses by location with TE/VS and without TE/VS.

Net Societal Benefits is determined as the Consumer Benefits plus (a) Transmission Owners' benefits reflected in reduced congestion cost and (b) increased

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[1] Decision 06-11-018 November 9, 2006, "Opinion on Methodology for Economic Assessment of Transmission Projects"

producers' or generators' surplus. Although, only producer surplus from utility generators should be considered[2], I have discounted all producers' surplus in my calculation due to the time limitation in conducting this analysis. Therefore, the net Societal Benefit I am presenting is very conservative since it discounts any production surplus from all generators in the CAISO.

Q. Please describe the general approach and PLEXOS modeling used in your analysis.

A. The general approach used in my analysis is to perform production cost simulations to quantify the economic benefits of the TE/VS interconnect project to California consumers and other market participants. I used PLEXOS, a commercially available optimization engine and market simulation tool, to model the full network topology of the CAISO footprint and calculate the generation and ancillary service dispatch, transmission flow and LMPs for 8760 hours in the study year. The production cost simulation was performed under a base case scenario without TE/VS in-service and then again with TE/VS interconnected. Cost savings or benefits to California consumers and other market participants are calculated by comparing the costs paid by consumers (and other market participants) in the two scenarios. If costs are lower with the TE/VS project in-service, then there is a net benefit. I also performed an analysis of a third scenario to assess the impact the TE/VS project has in providing an interconnection for the LEAPS project.

Q. Are the results of your modeling of the TE/VS and LEAPS projects utilized by any other witness to this proceeding?

[2] Utility owned generation flows to the CAISO's customers through retail ratemaking. Because profits to non-utility owned generation do not flow to the CAISO's customers, it is incorrect to include the producer surplus for those generators as a net benefit under the TEAM methodology.

A. Yes, the results of my analysis are used by my colleague Dr. Doug Bergman to perform the benefit-cost analysis for the TE/VS project.

Q. Why did you choose to use PLEXOS for the modeling you performed in this case?

A. PLEXOS is a proven, Windows-based analytical tool that ZGlobal has used for over four years to perform pricing simulations and economic assessments for our various client projects. With PLEXOS I am able to assess benefits for such projects consistent with the principles of TEAM's economic analysis, specifically: (i) I am able to quantify benefits to California consumers and set up appropriate economic criteria for cost/benefit analysis; (ii) I am able to use a full network model; (iii) I can use nodal market prices (including the capability to identify market power); and (iv) I am able to model risk and uncertainty via modeling sensitivity scenarios.

Q. Is PLEXOS an acceptable model to be used?

A. Yes, PLEXOS has been used by many power system engineers, utilities and ISO's such as CAISO and the Midwest ISO. In fact, CAISO made the following statements on page 11 of their Errata filing to the Rebuttal Testimony of the California Independent System Operator Corporation on June 15, 2007 for the Sunrise Powerlink Transmission Project[3], "In fact, it is generally accepted among power engineers that PTDF models are more accurate than transportation models (e.g., the model used by SBRP in this proceeding) which completely ignore the laws of physics. Both Gridview and PLEXOS are PTDF models that have been accepted by the CAISO and the Commission in the application of the CAISO's TEAM methodology." And further they state, "The CAISO believes that

[3] http://www.caiso.com/1c43/1c43e68414ce0.pdf

PLEXOS can produce reasonable and reliable results, as evidenced by the CAISO's own use of PLEXOS in other venues."

Q. Please explain how you developed your base case using PLEXOS, including the inputs for the modeling and the source of those inputs.

A. For my analysis, I started with our 2010-2020 ZGlobal long term production cost model and updated with the specific load, generation and transmission model assumptions that are consistent with key drivers published by the CAISO for 2015, including: (i) the latest projected 1 in 10 load forecast for 2015 published by the California Energy Commission ("CEC"), (ii) approved CAISO transmission projects such as the Sunrise Powerlink ("Sunrise"), Techachapi Renewable Transmission Project, the Colorado River-Devers-Valley #2 500 kV line and the Colorado River 500 kV substation looping in the Palo Verde-Devers 500 kV #1 line, (iii) San Diego area resource retirements and (iv) the anticipated level of 20% renewables based on the latest PUC projection of approximately 20% by 2015. Exhibit 2, "Plexos Modeling Assumptions for the TE/VS Project", provides full details on the inputs and the source of the inputs into the production cost model used for my analysis.

Q. What are the assumptions for the level of capacity available in the Greater Imperial Valley-San Diego area starting 2015? Please list the resources you modeled in the basecase, and the cases with TE/VS and TE/VS plus LEAPS.

A. The total available capacity starting 2015 is 4008 MW. Additionally, I assumed that all South Bay units and Encina 1-3 are retired. Exhibit 3 contains all the resources modeled in PLEXOS for the San Diego area:

Q. What level of renewable energy imports from the Imperial Irrigation District (IID) did you assume utilized the San Diego Gas & Electric (SDG&E) Sunrise project?

A. None. I was unable to identify any planned renewable interconnections or Power Purchase Agreements (PPAs) from IID service area into Sunrise. Per the latest CAISO interconnection queue, all requested renewable interconnections that would utilize the Sunrise are located outside the IID service area. There is over 5000 MW of capacity currently in the interconnection queue and just over 1100 MW have executed an Interconnection Agreement (IA) or are in-progress. Accordingly, I modeled a total of 1000 MW of total capacity from renewable resources interconnecting to Sunrise at Imperial Valley Substation.

Q. What resource mix did you model interconnecting to Sunrise?

A. I assumed mostly solar and some wind resources are interconnected to Sunrise based on the project requests listed in the CAISO interconnection queue. During peak hours, the line is loaded near 1000 MW during peak hours in all three scenarios (basecase, TE/VS and TE/VS with LEAPS).

Q. Are there any differences in available resource capacity between the basecase and the case with TE/VS? Explain.

A. Yes. In the case with TE/VS, I have modeled increased available capacity from geothermal resources located in the Imperial North area in conjunction with increased import capability from Path 42 upgrades. The Imperial North area is rich in renewable resources especially geothermal. Path 42 consists of two (2) 230 kV transmission circuits known as the "KN and KS" lines. The transmission lines are independently owned in separate parts by Imperial Irrigation District (IID) and Southern California Edison (SCE) and run from the IID-owned Coachella Valley substation to the SCE-owned Mirage and Devers substations. The current Path 42 rating is 600 MW.

The Path 42 upgrade would consist of upgrading 20 miles of existing double circuit single conductor 230 kV transmission lines to bundle (two conductors per phase) conductors.[4] The project also includes line termination equipment at both ends of the line and its associated substation upgrades. The project will increase the thermal rating capacity of the IID to SCE interconnection from 600 MW to 1455 MW. To achieve the maximum path rating, the project requires SCE to upgrade to bundle conductor, 15 miles of double circuit 230kV transmission line from SCE's Mirage to Devers substations.

The basecase does not include the upgrade on Path 42 since, absent TE/VS, renewable energy from Imperial North via Path 42 could not be delivered to the San Diego area due to the lack of a transmission outlet. With TE/VS, renewable energy from IID is able to reach San Diego through the TE/VS project. The TE/VS project connects the SDG&E and SCE systems to provide a path to access the renewable energy from Imperial North.

Q. What is the renewable energy mix assumed to use Path 42?

A. I assumed that the upgraded Path 42 is able to transfer 1400 MW which is an increase of 800 MW of renewable import capacity from IID into CAISO from the basecase. I assumed that 80% of the added resource capacity is from geothermal resources and 20% is from solar resources.

Q. How are the costs of the renewable resources from Imperial North taken into account in the analysis?

[4] http://www.oatioasis.com/IID/IIDdocs/Path_42_Upgrade_Open_Season_Presentation_06_15.pdf

A. The cost of these resources is taken into account in the RPS benefit calculation performed by Dr. Bergman.

Q. Can the TE/VS project deliver renewable energy to San Diego absent Path 42?

A. Yes. The TE/VS project can deliver renewable energy to San Diego from SCE and PG&E systems. I chose to include the Path 42 upgrades since (1) according to CEC RETI, CTPG and IID, the resources in Imperial North are available, (2) transmission is planned at reasonable cost, (3) the cost of the renewable energy from this area is competitive, and (4) the location of these resources are within California.

Q. Absent TE/VS, can renewable energy be delivered to the San Diego area?

A. In my opinion, in order to meet the 33% RPS requirement for SDG&E, a new transmission line will need to be built to access renewables located outside San Diego. I believe that the TE/VS project will serve this need.

Q. Please describe the outputs of the PLEXOS modeling and production cost simulation.

A. The outputs of the PLEXOS modeling and production cost simulation are LMPs for each supply and demand location in the CAISO including the three LMP components, for the Marginal Cost of Congestion (MCC), the Marginal Cost of Losses (MCL) and the system Marginal Energy Cost (MCE), transmission line flows, dispatch levels and production costs for each supply resource. The PLEXOS results are integrated into ZGlobal's GridSelect analytical tools to calculate CAISO Load Aggregation Point (LAP) prices, CAISO Trading Hub prices and economic factors consistent with settlement cost calculations in accordance with CAISO market rules. The hourly economic factors are then used to calculate potential energy cost savings of the TE/VS project from the perspective of California market participants using the methodology and computations described herein.

The benefits of TE/VS are quantified in two components: (1) Consumer Benefit and (2) Societal Benefit. The Consumer Benefit is determined as the energy cost savings to buyers of energy in California. The Societal Benefit includes the Consumer Benefit, and add-on increases to production surplus and congestion revenue savings.

Consumer Benefit Calculation

Demand in CAISO is charged a weighted average nodal price specific to its Load Aggregation Point (LAP LMP). There are 3 LAPs defined: a) PG&E, b) SCE and c) SDG&E. The LAP LMP includes not only the marginal cost of energy but also the costs paid for congestion and losses.[5] For our analysis, we will include the marginal energy, marginal congestion and marginal loss cost paid by consumers when determining the hourly *(t)* Load Market Cost (LMC) as follows:

$$LMC_t = \sum_i (DemandMWh_{i,t} * LAP\_LMP_t)$$

where,

Demand $MWh_{i,t}$ = Demand (MWh) in Load Aggregation Point (LAP) *i* for hour *t*, and

$LAP\_LMP_{i,t}$ = the LMP for LAP *i*, hour *t* ($/MWh)

The savings to consumers' total market cost is the cost difference between the LMC with and without the project (or between the reference and the change case).

$$\Delta LMC_t = LMC_{t\ w} - LMC_{t\ w/o}$$

where,

[5] The LMP can be decomposed into three components: (1) Marginal Cost of Energy or MCE, (2) Marginal Congestion or MCC and (3) Marginal Cost of Losses or MCL so that market participants can determine marginal energy costs separately from the marginal congestion and loss costs.

LMC_w = the consumer's market cost ($) with the Project or the change case,

$LMC_{w/o}$ = the consumer's market cost ($) without the Project or the reference case.

The LMC paid by consumers includes the charge to Demand for marginal losses, or MCL. The MCL for the system represents the net cost of losses paid by consumers at the marginal loss rates. The marginal loss component of the LMP charges consumers for the incremental quantity (MWs) of transmission losses in the network resulting when serving an increment of load at the LAPs from the CAISO-determined reference busses. With this methodology, consumers are "over-charged" for losses compared with if charged based on the actual MW difference between supply and demand which are the actual losses in the system. Any amount "over-collected" are termed "Marginal Loss Surplus" and are refunded back to consumers in the CAISO settlement process. For the analysis, the Marginal Loss Surplus (MLS) will need to be subtracted from the LMC when calculating the net consumer benefit for Energy costs.

Thus, the total consumer benefit or "Benefit to Load" (BTL) due to Energy cost savings is calculated as:

$$BTLt = -1 * (\Delta LMCt - \Delta MLSt)$$

We use a (-1) multiplier to indicate a positive dollar amount represents a cost savings to the consumer.

Marginal Loss Surplus (MLS) Calculation

The Marginal Loss Surplus (MLS) is derived as the difference between the Transaction Costs and the Congestion Cost. The MLS represents over-collection of costs associated with marginal losses. MLS cannot be considered a net benefit to load. Per

CAISO settlement rules entities representing Demand are refunded these costs during the settlements process and thus are excluded from the total consumer benefits.

$$MLS_t = TC_t - CR_t$$

And, the Marginal Loss Surplus reduction,

$$\Delta MLS_t = MLS_{t,w} - MLS_{t,w/o}$$

where,

MLSw = the system's Marginal Loss Surplus with the Project ($),

MLSw/o = the system's Marginal Loss Surplus without the Project ($)

<u>Transaction Cost (TC) Calculation</u>

In the CAISO markets, suppliers are paid the nodal-specific LMP while consumers are charged a weighted-average LMP for its Load Aggregation Point (LAP). Since LMPs reflect the marginal cost of congestion and losses to inject or withdraw energy at that pricing point, the difference between what consumers are charged and what suppliers are paid reflect the total system congestion and loss cost for transferring energy between the nodal injection points and the LAPs where load withdraws the energy. For this analysis, we refer to this as the system Transaction Costs.

In the CAISO, there are three LAP areas (PG&E, SCE and SDG&E) with separate weighted-average LMPs (or LAP LMPs). The system Transaction Cost is calculated for each hour t in the study period as follows:

$$TC_t = (\sum_i DemandMWh_{i,t} * LAP\_LMP_{i,t}) - \sum_k (SupplyMWh_{k,t} * LMP_{k,t})$$

$$LAP\_LMP_{i,t} = MCE_t + LAP\_MCC_{i,t} + LAP\_MCL_{i,t}$$

$$LMP_{k,t} = MCE_t + MCC_{k,t} + MCL_{k,t}$$

where,

Demand $MWh_{i,t}$ = Demand (MWh) in Load Aggregation Point (LAP) *i* for hour *t*

$LAP\_LMP_{i,t}$ = Locational Marginal Price for LAP *i,* hour *t* ($/MWh)

MCE_t = Marginal Cost of Energy component of the LMP for hour *t* ($/MWh)

$LAP\_MCC_{i,t}$ = MCC component of the LMP for LAP *i*, hour *t* ($/MWh)

$LAP\_MCL_{i,t}$ = MCL component of the LMP for LAP *i*, hour *t* ($/MWh)

Supply $MWh_{k,t}$ = Energy dispatch (MWh) for generation or import resource *k* in hour

$LMP_{k,t}$ = Locational Marginal Price for generation or import resource *k* in hour *t* ($/MWh)

$MCC_{k,t}$ = MCC component of the LMP generation or import resource *k*, hour *t* ($/MWh)

$MCL_{k,t}$ = MCL component of the LMP for generation or import resource *k*, hour *t* ($/MWh)

For the analysis, we measure the Transaction Cost savings benefit to Market Participants as the cost difference between the TC with and without the Project.

$$\Delta TC_t = TC_{t\ w} - TC_{t\ w/o}$$

where,

TC_w = the system's transaction cost with the Project ($),

$TC_{w/o}$ = the system's transaction cost without the Project ($)

Congestion Revenue Calculation

The marginal congestion cost is also the Congestion Revenue (CR) paid to Congestion Revenue Rights (CRR) holders under the CAISO nodal market. Because the MCC is a component of the LMP, congestion costs are charged (or paid) to both suppliers and consumers in the market. Congestion Cost savings therefore are not exclusively a Consumer Benefit and will be included in the Societal Benefit cost.

The Congestion Cost is calculated each hour t as the sum of Congestion Revenue increase or decrease charged or paid to the suppliers at their nodal MCC and the Marginal Congestion Cost charged or paid to the load at the LAP_MCC. This Congestion Cost also reflects the revenue available to the market as a whole for funding CRRs.

$$\mathrm{CR}_t = \left(\sum_i DemandMWh_{i,t} * LAP\_MCC_{i,t}\right) - \sum_k SupplyMWh_{k,t} * MCC_{k,t}$$

Once the CR is calculated for the scenarios, the Congestion Revenue can be quantified as the cost difference between the congestion cost (CR) with and without the Project.

$$\Delta \mathrm{CR}_t = \mathrm{CR}_{t\ w} - \mathrm{CR}_{t\ w/o}$$

where,

CR_w = Total congestion revenue with the Project ($)

$\mathrm{CR}_{w/o}$ = Total congestion revenue without the Project ($)

<u>Societal Benefit Calculation</u>

The additional transmission capacity provided by the Project also provides benefit to the market as a whole. The Societal Benefits measure the cost savings and revenue surpluses to all CAISO Market Participants by summing the Consumer Benefits, Production Surplus increases and the Marginal Congestion Cost savings[6].

$$\text{Societal Benefit} = \text{BTL} + \Delta\text{PS} - \Delta\text{CR}$$

In addition to the Consumer Benefit components, the increase in the Production Surplus is included in the Societal Benefits. Energy from lower cost generators (variable production cost) benefit the market as a whole; and if after netting revenues earned by

[6] Formulas use a negative sign convention (dollar amount) to reflect a congestion cost savings.

Suppliers result in higher profits between sensitivities (with and without the project in-service), there is a Production Surplus *increase* which represents a benefit to suppliers. Finally, Congestion Cost savings (or Congestion Revenue decreases) are added because they represent cost savings to both consumers and suppliers in the market.

The economic benefit to suppliers due to the Project is measured by comparing the Production Surplus between sensitivities. The Production Surplus is derived by taking the difference between revenues earned by generators at their LMPs and their Production Costs.

$$PS_t = PR_t - PC_t$$

The Production Surplus increase to the market with the Project in-service is calculated as,

$$\Delta PS_t = PS_{t\ w} - PS_{t\ w/o}$$

where,

PS_w = the Production Surplus with the Project ($)

$PS_{w/o}$ = the Production Surplus without the Project

Production Cost Savings

The fundamental economic impact of a transmission upgrade is that it may make the system more efficient and thus lead to more efficient unit commitment and economic dispatch. The economic impact is measured by calculating the Suppliers' Production Cost savings which quantifies the reduction in total variable production cost to serve the load[7]. The net Production Cost savings due to the Project is then calculated as,

$$\Delta PC = PC_w - PC_{w/o}.$$

[7] For this analysis, it is assumed that demand is inelastic, that is, the same Demand MWh are used in each case.

Where,

PC_w = the system's total variable production cost with the Project ($)

$PC_{w/o}$ = the system's total variable production cost without the Project ($)

The Production Cost is calculated for the system by summing the costs for all suppliers on the grid which is its energy dispatch in MWh multiplied by its fuel costs plus its variable operating costs. The system Production Cost is calculated for each hour *t* in the sensitivity year as follows:

$$PC_t = \sum_k (G_{k,t} * FC_k + VOM_k)$$

where,

FC_k is supplier *k's* fuel cost at its average heat rate ($/MWh)[8]

VOM_k is supplier *k's* variable operations and maintenance costs ($)

<u>Production Revenues</u>

The Production Revenues calculate the payments to suppliers at the nodal LMPs for the various sensitivities. If overall revenues decrease with the TE/VS project in place, it reflects an increased ability for other generation sources to serve the load center. Thus, with the increased capability to bring in more renewable energy, the LMPs and resulting revenues will decrease.

The Production Revenue is calculated for each hour *t* in the study period as follows:

$$PR_t = \sum_i (SupplyMWh_{k,t} * LMP_{k,t})$$

[8] Unit-commitment is included in the simulation; the formula can be extended to include start-up costs and no-load costs.

where,

$SupplyMWh_{k,t}$ = Energy dispatch (MWh) for generation or import resource k in hour t

$LMP_{k,t}$ = Locational Marginal Price for generation or import resource k in hour t ($/MWh)

II. Summary of Benefits from TE/VS

Q. Would energy benefits be realized?

A. Yes. My analysis results in a Consumer Benefit of $81.5 million dollars and a net Societal Benefit of $68.3 million dollars for the TE/VS project. Exhibit 4 provides the summary and breakdown of the annual benefits.

Q. What would be the net changes in producer surplus?

A. The net change in the producer surplus is a decrease of $33.4 million dollars.

Q. What would be the net changes in congestion revenues?

A. The net change in congestion revenues is a decrease of $20.2 million dollars.

III. Summary of Benefits of TE/VS to Interconnect LEAPS

Q. Can you explain the modeling you performed using the TE/VS plus LEAPS case and the results of that modeling?

A. LEAPS is modeled as a merchant generator such that it would be paid at its LMP for hours it sold energy to the CAISO market and be charged the SCE LAP price for hours it purchased energy to pump water to the upper reservoir. In order to determine the optimal hours for the plant to operate, I calculated an economic pump and generation dispatch pattern based on the SCE LAP and SP15 trading hub prices generated from the production cost runs for the TE/VS-only scenario and an assumed storage level in the reservoir for the month. The optimization is done for a monthly period using the same water storage assumption for each month.

The resulting dispatch schedule for LEAPS was then used in the production cost simulation for the entire year to determine new LMPs and hourly economic factors. Using these hourly prices and economic factors, I determined the Consumer and net Societal Benefits that would be realized from the TE/VS project to interconnect LEAPS.

Q. Would energy benefits be realized?

A. Yes. My analysis results in a Consumer Benefit of $133.7 million dollars and a net Societal Benefit of $116.7 million dollars for the TE/VS project to interconnect LEAPS. Exhibit 5 provides the summary and breakdown of the annual benefits.

Q. What would be the net changes in producer surplus?

A. The net change in the producer surplus is a decrease of $35 million dollars.

Q. What would be the net changes in congestion revenues?

A. The net change in congestion revenues is a decrease of $18 million dollars.

Q. Does this conclude your testimony?

A. Yes, this concludes my testimony.

Exhibit 1

Christine Vangelatos, B.S., M.S.

Experience Summary

Extensive experience managing the day-to-day operations and transactions with California ISO market design and settlements. Extensive experience and professional ability to provide market settlement design analysis and review for the Market Redesign and Technology Upgrade program system implementation and California ISO Tariff filings. Expertise in using production cost models to analyze and forecast LMP prices for the California system.

Key Assignments
Director of Analytics, Manager of Settlement Projects, Lead Market Design Engineer

Education
B.S. Electrical Engineering, California Polytechnic State University, San Luis Obispo
M.S. Computer Information Systems, University of Phoenix

Experience
18 years

Relevant Expertise
- *Energy Settlements Expert*
- *Implementation of Large Scale Market Systems*
- *Power Flow Analysis*
- *Production Cost Modeling*
- *Locational Marginal Pricing Calculation and Verification*
- *Dispute Resolution*
- *Transaction Evaluation*
- *CAISO Tariff and Procedures*

Director of Analytics, ZGlobal, Folsom, CA, 2006- Present

Christine is our expert in California markets, transmission pricing, transmission modeling, LMP price calculation and energy settlement. Provides expertise and analysis in California nodal pricing, market design and settlements, including providing results analysis of ZGlobal's production cost economic model. One of the key engineers responsible for running computer simulations that forecast energy dispatch and calculate production costs for the California ISO (CAISO) grid.

California Independent System Operator, Folsom, CA 1997- 2006

Manager, Settlement Projects
Manage the day-to-day operations, staff and have overall responsibility for design, implementation or analysis of business processes and charge equation configuration for the California ISO's settlement and billing systems. Provide settlements' technical analysis and consulting for the Market Redesign and Technology Upgrade (MRTU) project including providing management with recommendations regarding new technologies and implementation methods supporting CAISO market design and operations objectives. Served as the Settlement and Market Clearing System (SaMC) project lead. Recommended solutions, defined business requirements and managed implementation efforts for market designs related to Settlements' process and charge calculations.

Manager, Market Quality and Market Integration
Manage the day-to-day operations and staff responsible for the quality of "bid to book" market transaction data prior to the settlements process. Oversee technical analysis and resolution of Settlement disputes by Market Quality Engineering Analysts. Provide coaching and guidance for employees' work assignments, training needs and activities Manage Market Operations testing and support engineers to collaboratively test, implement and support functionality for CAISO business systems and automated processes including SI/SA, SLIC, BITS, and data transfer processes to Settlements.

Lead Market Design Engineer for Market Operations and Start-up Team Member
Lead Market Operations testing and support engineers to collaboratively test, implement and support functionality for SI/SA systems. Coordinated successful Market Operations' acceptance testing and implementation of the SI/SA 1999 Ancillary Service Redesign projects. Provided 24x7 on-call SI/SA system support for Grid Resource Coordinators, Scheduling Coordinators and other SI/SA system users. Prepared and reviewed functional requirements documents for various SI/SA system projects ensuring its consistency with ISO Tariff and policy Grid operations engineering experience.

Pacific Gas & Electric Company, 1992 - 1997

Lead Power System Engineer in the System Operation department.

PG&E representative on the Western Power Exchange (WEPEX) Team to write RFPs and evaluate vendor bids for the systems to be used at the Independent System Operator. Five years grid operations engineering experience including:

- Performed post-transient power flow analysis to determine simultaneous California-Oregon Intertie and Pacific DC Intertie transfer limits for various operating scenarios.
- Designed a methodology and an "on-line" computation application for calculating transmission path transfer capabilities for the South-of-Tesla (Path 15) corridor, and authored operating procedures for its implementation by grid operators.
- Evaluated San Francisco Bay Area grid constraints and recommended reliability "must-run" generation instructions to system grid operators.
- Analyzed potential system grid problems and developed contingency solutions to support transmission grid maintenance coordination and while on-call during system emergencies.

Exhibit 2

Exhibit 2

Plexos Modeling Assumptions for the TE/VS Project

1.1 Basecase

The Plexos model used in this study is based on the 2010-2020 model developed by ZGlobal based on the California Independent System Operator (CAISO) full network model. For the TE/VS project economic study, this base model has been updated with the latest CAISO-approved transmission projects, and uses the assumptions described in this document for demand forecast, generation, fuel price forecast, and imports for a 2015 scenario year.

1.2 Demand Forecast

The load forecast is modeled by utilizing the California Energy Commission (CEC) peak load forecasts as detailed in the "California Energy Demand 2010-2020, Adopted Forecast" final report, dated December 2009[1]. The particular details derived from the report are the electricity deliveries to end users (GWh) and the 1-in-10 Net Electricity Peak Demand (MW) for each Investor-Owned Utility (IOU) . The peak load values are load and do not include losses or pump load. Figure 1 provides the 2015 "1 in 10" peak load and energy assumptions.

2015 1-in-10 Peak Demand MW and Annual GWh		
IOU	Peak Demand (MW)	Annual GWh
PG&E	24,537	111.8
SCE	27,062	104.8
SDG&E	5341	22.2

Figure 1. 2015 Demand Forecast

1.3 Transmission Projects

Transmission projects that have received CAISO Board of Governors approval will be modeled in the TE/VS analysis. The significant transmission projects include:

1. Palo Verde–Devers #2 Project (Colorado River–Valley 500 kV)
2. Tehachapi Transmission Project
3. Sunrise Powerlink Project

Green Path North is not modeled in any of the cases.

1.3.1 Tehachapi Renewable Transmission Project (TRTP)

SCE's TRTP is designed to help the state reach Renewable Portfolio Standards (RPS). The project involves the interconnection of approximately 4500 MW of renewable resources and several segments of new transmission to accommodate the new generation. The entire project will be interconnected in stages as described in Figure 2:

[1] Kavalec, Chris and Tom Gorin, 2009. California Energy Demand 2010-2020, Adopted Forecast. California Energy Commission. CEC-200-2009-012-CMF

Implementation Number	Description	In-Service Date
1	• New Antelope-Vincent 500kV#2 Line (Energized to 230kV) o Rating = 1464MW • New Windhub 500kV Substation (Energized to 230kV) • New Antelope-Pardee 500kV line (Energized to 230kV) • New Antelope-Windhub 500kV Line (Energized to 230kV)	10/1/2010
2	• Reconductor the existing Antelope-Vincent 230kV #1 line (Energized at 230kV) o Rating = 1464MW	10/1/2012

3	• New Whirlwind 500kV Station
	• New Antelope-Whirlwind 500kV Line
	    o Rating = 3184MW
	• Energize Windhub to 500kV
	• Energize Antelope-Vincent #1 & #2 Lines to 500kV
	    o Rating = 3184MW
	• Energize Antelope-Windhub Line to 500kV
	    o Rating = 3184MW
	• Energize Antelope-Pardee Line to 500kV
	    o Rating = 3184MW
		10/1/2013

4	• Vincent-Mesa 230kV line reconductor to 500kV
	    o Rating = 3184MW
	• New Windhub-Whirlwind 500kV Line
	    o Rating = 3184MW
	    o Replace existing Vincent-Rio Hondo 220kV lines with double circuit 500kV
	    o Replace Rio Hondo-Mesa Cal 220kV lines with double circuit 500kV
	• Rebuild the Mesa-Mira Loma 220kV line to 500kV Service
	• Rebuild the single circuit Chino-Mira Loma 220kV to double circuit
	• Replace transmission between Vincent and Gould substations with single circuit 500kV transmission.
	• Install a second 220kV transmission line from Gould Substation to Mesa substation
		1/1/2015

Figure 2: Tehachapi Build Out

The CAISO interconnection queue lists the projects in Figure 3 for the Tehachapi region. The build out is targeted for completion by 2015 and so the model used in the TE/VS study assumes 4439 MW of available new Tehachapi project wind generation.

Queue Position	Application Status	Type	Fuel	Summer	Station or Transmission Line	Proposed On-line Date (as filed with IR)	Interconnection Agreement Status
79	Active - Serial	WT	W	51	Windhub Substation 66kV bus	3/31/2010	In Progress
91	Active - Serial	WT	W	51	Windhub Substation 66kV bus	3/31/2010	In Progress
73	Active - Serial	WT	W	250	Whirlwind Substation 230kV bus	10/31/2010	
96	Active - Serial	WT	W	600	Tehachapi Conceptual Substation #1	12/31/2010	LGIA Executed
132	Active - Serial	WT	W	297	Highwind Substation 230kV bus	12/31/2010	In Progress
537A	Active - SGIP	WT	W	20	Highwind Substation	4/1/2011	
84	Active - Serial	WT	W	340	Whirlwind Substation 230kV	12/31/2011	
94	Active - Serial	WT	W	180	Highwind Substation 220kV	12/31/2011	In Progress
95	Active - Serial	WT	W	550	Tehachapi Conceptual Substation #1	12/31/2011	In Progress
485	Active - SGIP	WT	W	19.9	Highwind Substation 230kV bus	6/30/2012	
505	Active - Cluster #1	WT/PV	W/S	1100	Highwind-Windhub 230kV line	11/30/2012	
188	Transition Cluster	WT	W	200	Windhub Substation 230kV	12/1/2012	
93	Active - Serial	WT	W	220	Tehachapi Conceptual Substation #1	12/31/2012	
153	Active - Serial	WT	W	100	Whirlwind Substation 230kV	12/31/2012	
409	Transition Cluster	WT	W	150	Highwind Substation 230kV	12/31/2012	
97	Active - Serial	WT	W	160	Whirlwind Substation 220kV bus	12/31/2013	In Progress
119	Active - Serial	WT	W	500	Windhub Substation 230kV	12/31/2013	
175	Transition Cluster	WT	W	650	SCE Proposed Whirlwind 230kV Substation	12/31/2014	
			Total	4438.9			

Total into Windhub	3589
Total into Whirlwind	850
Total	4439

Figure 3: CAISO Interconnection Queue for Tehachapi Region

1.4 Generation Assumptions

1.4.1 Generation Additions and Retirements

The basecase assumes generation status based on both the published 2010 CAISO Transmission Plan and the California Energy Commission (CEC) Energy Facility Status page on their website. Figure 4 reflects the generation additions and retirement assumptions for the San Diego area used in the study.

Generation	Status
Otay Mesa	Online
Miramar 2	Online
Orange Grove	Online
Lake Hodges	Online
South Bay	Retired
Encina 1-3	Retired

Figure 4. San Diego Area Generation Additions and Retirements

1.4.2 Once-Through-Cooled Power Plants

The California Energy Commission (CEC) released in February of 2010 a staff report titled "The Roll of Aging and Once-Through-Cooled Power Plants in California – An Update"[2]. Within the report the staff identifies all the Once-Through-Cooled (OTC) resources in California that the State Water Resources Control Board (SWRCB) recommends for replacement or elimination. Figure 5 outlines the list of OTC units by Local Capacity Area (LCR), along with the SWRCB proposed elimination dates and the status of each unit in the model used for the 2015 TE/VS analysis.

LCR Area	OTC Units	SWRCB Proposed Elimination Date	Notes	Generator Status for 2015
Greater Bay Area	Contra Costa 6 and 7 (340MW Each)	2012	Need replacement units or additional transmission into the bay to allow for retirement	Re-power (Marsh Landing Generation Station 2012)
	Pittsburg 5 and 6 (325MW Each)	December 2017		On-line
	Potrero 3 (207MW)	December 2011		Retire
Los Angeles Basin	Alamitos 1 and 2 (175 Each)	December 2020	Need replacement units or additional transmission into the bay to allow for retirement	Online
	Alamitos 3 (326MW)			Online
	Alamitos 4 (324MW)			Online
	Alamitos 5 and 6 (485 Each)			Online

2 http://www.energy.ca.gov/2009publications/CEC-200-2009-018/CEC-200-2009-018.PDF

LCR Area	OTC Units	SWRCB Proposed Elimination Date	Notes	Generator Status for 2015
	El Segundo 3 and 4 (335MW Each)	December 2015 (re-power)		Re-power project Combined Cycle 670 MW, HR=6500
	Huntington Beach 1 and 2 (215 Each)	December 2020		Online
	Huntington Beach 3 and 4 (225 Each)	December 2020		Online
	Redondo Beach 5 (179MW)	December 2020		Online
	Redondo Beach 6 (175MW)	December 2020		Online
	Redondo Beach 7 (493MW)	December 2020		Online
	Redondo Beach 8 (496MW)	December 2020		Online
Big Creek/Ventura	Mandalay 1 and 2 (218MW each)	December 2020		Online
	Ormond Beach 1 and 2 (806MW Each)	December 2020		Online
San Diego	Encina 1 (107MW)	December 2017	Carlsbad Energy Center will replace this	Retire
	Encina 2 (104MW)	December 2017		Retire
	Encina 3 (110MW)	December 2017		Retire
	Encina 4 (300MW)	December 2017	Need replacement capacity	Online
	Encina 5 (330MW)	December 2017		Online
	South Bay 1 and 2 (136MW Each)	December 2012	Not needed once Sunrise is in-service	Retire
	South Bay 3 (210MW)	December 2012	Not needed with addition of Otay Mesa	Retire
	South Bay 4 (214MW)	December 2012		Retire
Gas-Fired Not in LCR Area	Morro Bay 3 and 4 (300MW Each)	December 2015	Can retire without threatening reliability. Dynegy has no plan to re-power.	Retire
	Moss Landing 6 and 7 (702MW Each)	December 2017	Would require replacement Capacity	Online
	Moss Landing 1 and 2 (540MW Each)	December 2017	Would require replacement Capacity	Stay Online – as is. Came online in 2002.

Figure 5: OTC Units in California

1.4.3 Hydro Generation

The hydro generation profiles were developed by utilizing a base hydro profile for each season, then scaling the base profile proportionately to the individual hydro stations. Similar curves have been developed for the pump storage resources in California, replacing the minimum output hours with pumping schedules.

- Spring: April 1 through June 31
- Summer: July 1 through September 30
- Fall/Winter: October 1 through March 31

The weekend and holiday dispatch is less because the load is less. The hydro output is adjusted on average to be 25% less than the weekday dispatch.

The 2015 TE/VS project economic study assumes an average hydro generation pattern. Figure 6 below outlines the difference in total hydro output for each season in MWh.

Scenario	Spring	Summer	Fall/Winter	Total
Avg	7,881,683	7,112,407	12,745,392	27,749,482

Figure 6: Seasonal Hydro MWh Comparison

1.4.4 Thermal Generation

Natural gas fired generation resources are modeled using heat rates, start-up costs, minimum load, minimum up/down times, and ramp rates. Additionally, Variable Operation and Maintenance Costs (VOM), can be included to reflect additional costs or bidding behavior. Figure 7 shows the typical Heat Rates used in the model for various generator types. For year 2015, it is assumed that advances in generator efficiency will continue as has been the trend over the past 10 years. New generation additions are modeled with Heat Rates slightly more efficient than resources that have come online between 2000 and 2010 (Figure 8). For example, a combined cycle proposed for 2017, will have a heat rate in the 6500 to 7000 MMBtu range. This is typical of the most efficient resources on the system today.

Resource Type	General Size (MW)	Avg. Heat Rate (Btu/KWh)		
		Maximum	Minimum	Average
Steam Turbine	165	11,400	8,300	10,056
	340	11,301	9,702	10,686
	750	10,900	10,400	10,500
Combined Cycle	Various	8,500	7,700	8,100
Combustion Turbine	Various	15,800	10,233	12,242

Figure 7: Heat Rate Ranges for Type and Size of Gas Fired Generators

	Average	Max	Min
CC	8374	9425	7117
CT	10087	14000	7900
ST1	11526	15800	9889

	Average	Max	Min
ST2	10667	13039	9500
ST3	9995	10542	9325

Figure 8: 2010 Heat Rate Ranges for Type and Size of Gas Fired Generators

1.4.5 Wind Generation

Wind generation resources are modeled using the same approach as the hydro, from a base wind profile. Wind generally produces the most power in the evening and little during the daytime hours. Figure 9 illustrates the average base profile curve. The annual capacity factor of the modeled wind resources is 33%.

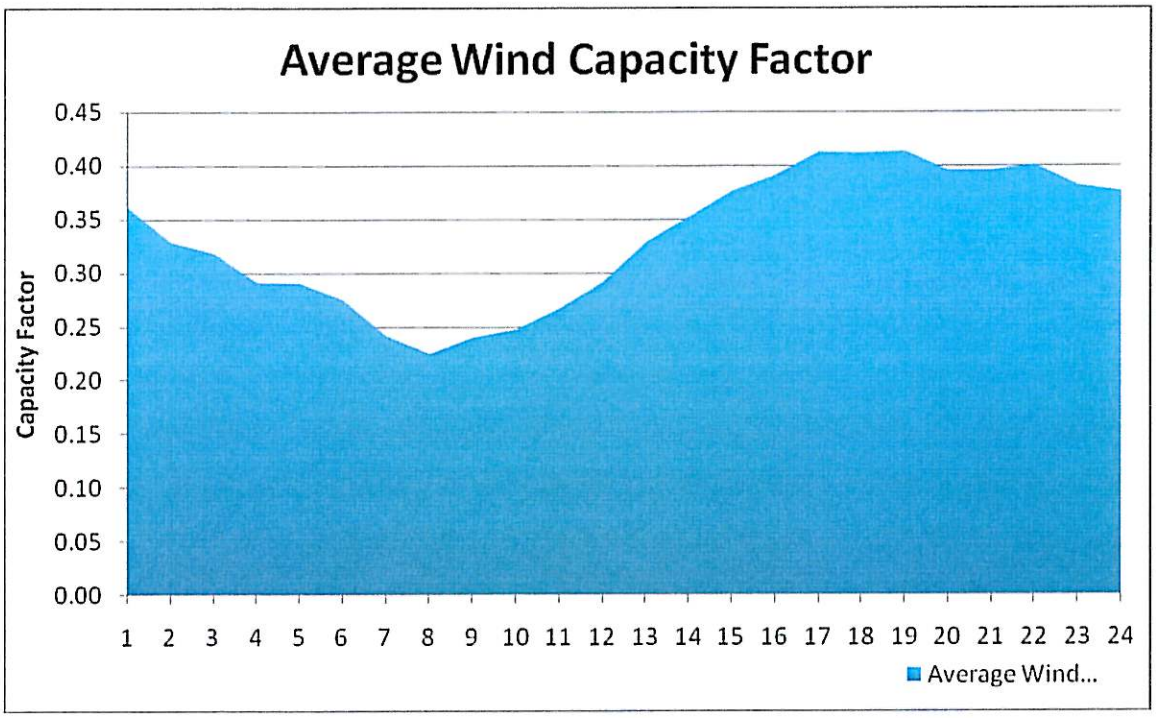

Figure 9: Wind Generation Profile

1.4.6 QF Generation

Production by Qualifying Facility (QF) generation plants does not typically fluctuate on a large-scale throughout the day. These units are dispatched at their maximum output.

For 2015, the majority of QF's will be reaching 25 to 30 years in operation. As such, these facilities are in general fully depreciated and no longer carry the financial burden of development and construction. Consequently, these facilities, even at significantly reduced energy contract prices, will continue to operate. It is our assumption, that even absent a contract, these facilities will continue to produce energy and become active in the CAISO energy markets. This assumption is driven by the economics, in that the facilities are fully depreciated and capable of earning a profit even if simply generating into the

ISO uninstructed and earning the Real-time LMP. Regardless of their approach to the market, it is expected that they will continue to run at maximum output.

1.4.7 Solar Generation

Production by Solar generation plants is assumed to peak in the summer months and produce the most during the daylight hours. See Figures 10 and 11 for illustrations of the solar dispatch.

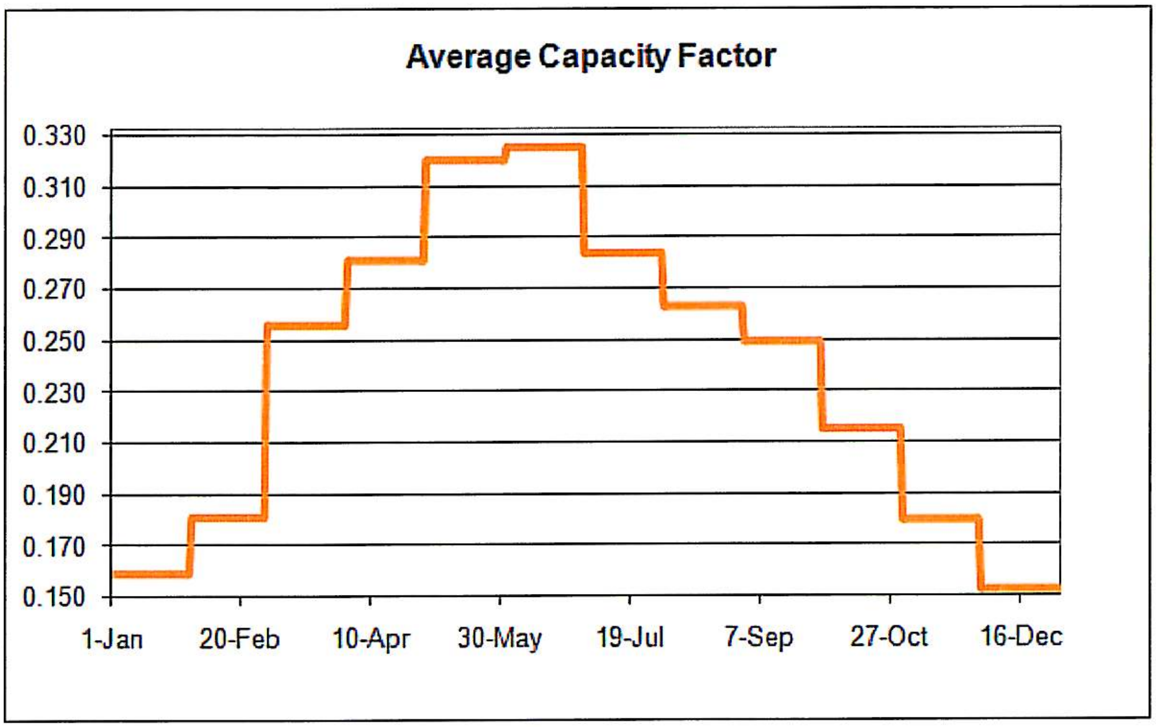

Figure 10: Average Capacity Factor

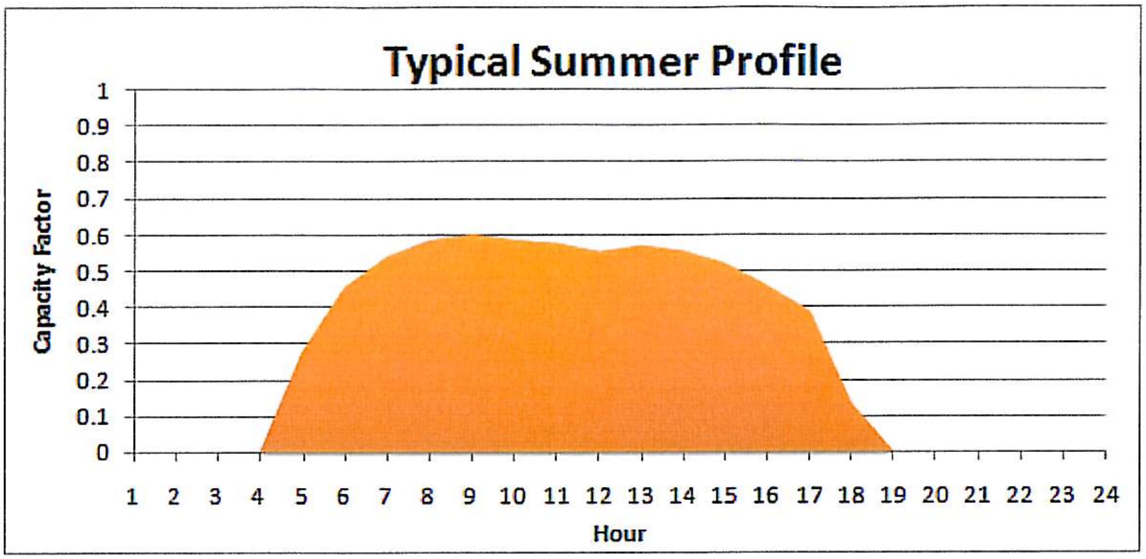

Figure 11: Typical Daily Summer Profile

1.4.8 Biomass Generation

The production profile of Biomass generation is assumed to be constant throughout the day and slightly fluctuate by season. The assumption for the daily peak annual profile dispatch ranges between .80 to 1.0 capacity factor for summer and winter respectively.

1.4.9 Geothermal Generation

The production profile of Geothermal generation is assumed to be at full load during peak hours and 95% of full during the off peak hours. During the summer months however, there is a slight de-rate associated with the higher temperatures. The profile is assumed 95% of full load on and off peak during the summer months.

1.4.10 California Pumps

The California aqueduct imposes a significant amount of load on the system. Figure 12 below gives a breakdown of the pump dispatch based on seasonal averages.

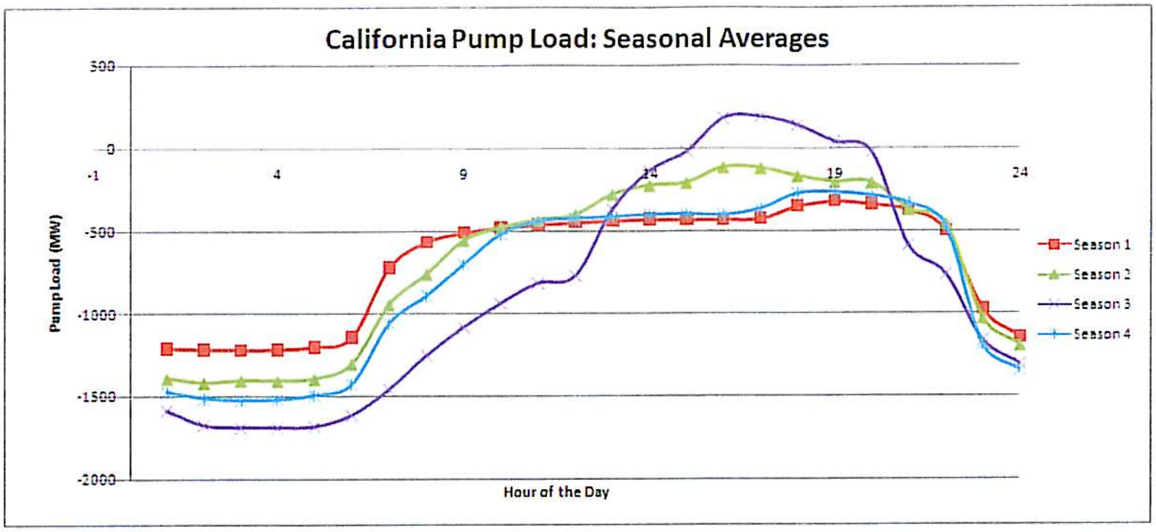

Figure 12: California Pump Load

1.5 Fuel Forecast

1.5.1 Fuel Forecast

2015 fuel prices are based on NYMEX forward curves and include delivery point adjustments (Figure 13).

Quarter	SCE/SDG&E	PG&E	IMPORT
Q1	7.42	7.64	7.64
Q2	6.64	7.00	7.00
Q3	6.91	7.16	7.16
Q4	7.26	7.57	7.57

Figure 13: 2015 Fuel Price Assumptions

1.6 Imports

A base offer quantity priced at very low heat rate is used to model the import "floor" at each applicable tie point. From that point a generator bid curve is created for each tie point comprised of various heat rate segments that reflect the mix of generation located in the region around the inter-tie.

Each import is designated as one of three types: Heavy Hydro, Base Loaded, and Mixture. The following example illustrates how the Heat Rate will be used for the Imports. For a 100 MW tie point consisting of Heavy Hydro the Heat Rates in Figure 14 will be applied to the model.

Number of Pairs	Heat Rate
Load Point	15
Load Point	40
Load Point	70
Load Point	90
Load Point	100
Heat Rate	6700
Heat Rate	7000
Heat Rate	8000
Heat Rate	9300
Heat Rate	12000

Figure 14: Example of Heat Rate Modeling for Import of Heavy Hydro

Contrasting the Heavy Hydro type with a Mixture type, the Heat Rates in Figure 15 will be applied to the model.

Number of Pairs	Heat Rate
Load Point	25
Load Point	36
Load Point	55
Load Point	77.5
Load Point	92.5
Load Point	100
Heat Rate	1000
Heat Rate	7700
Heat Rate	9700
Heat Rate	10350
Heat Rate	11400
Heat Rate	11850

Figure 15: Example of Heat Rate Modeling for Import of Mixed Resource Types

Intertie locations which have historically shown contractual dispatches or have largely hydro generation are categorized as Base Loaded and those paths are not modeled economically but rather from a pre-defined dispatch.

Exhibit 3

Exhibit 3

Generation Plants in the Greater Imperial Valley-San Diego Area

Generation Plant	Plexos Res ID	Resource Type	Max Capacity
Ciclo Mexicali	LAROA1_2_UNITA1	CMBCYC	170
CENTRAL LA ROSITA II COMBINED CYCLE	LAROA2_2_CTG 2S	CMBCYC	181.5
	LAROA2_2_STG 2C	CMBCYC	155
Otay Mesa	OTAYM_1_GT 1	CMBCYC	165
	OTAYM_1_GT 2	CMBCYC	165
	OTAYM_1_ST	CMBCYC	180
Palomar	PALOMR_7_CTG1	CMBCYC	180.6
	PALOMR_7_CTG2	CMBCYC	180.6
	PALOMR_7_STG3	CMBCYC	234.5
TERMOELECTRICA DE MEXICALI1	TERMEX_2_GTG1	CMBCYC	180
	TERMEX_2_GTG2	CMBCYC	180
	TERMEX_2_STG	CMBCYC	308
Encina	ENCINA_7_EA4	THERMAL	299
	ENCINA_7_EA5	THERMAL	329
Border/Calpeak	BORDER_6_UNITA1	PEAKER	49
El Cajon/Calpeak	ELCAJN_6_UNITA1	PEAKER	49
El Cajon GT	ELCAJN_7_GT1	PEAKER	16.36
Encina GT	ENCINA_7_GT1	PEAKER	14
MMC - Electrovest (Escondido)	ESCNDO_6_PL1X2	PEAKER	40
Escondido/Calpeak	ESCNDO_6_UNITB1	PEAKER	55
Kearny GT1	KEARNY_7_KY1	PEAKER	16.67
Kearny 2AB	KEARNY_7_KY2A	PEAKER	14.75
	KEARNY_7_KY2B	PEAKER	14.75
	KEARNY_7_KY2C	PEAKER	14.75
	KEARNY_7_KY2D	PEAKER	14.75
Kearny 3AB	KEARNY_7_KY3A	PEAKER	15.25
	KEARNY_7_KY3B	PEAKER	15.25
	KEARNY_7_KY3C	PEAKER	15.25
	KEARNY_7_KY3D	PEAKER	15.25
Larkspur Border 1	LARKSP_6_UNIT 1	PEAKER	49
Larkspur Border 2	LARKSP_6_UNIT 2	PEAKER	49
Miramar 1	MRGT_6_MMAREF	PEAKER	46
Miramar GT 1	MRGT_7_MR1A	PEAKER	18
Miramar GT 2	MRGT_7_MR1B	PEAKER	18
Orange Grove	OGE_1_UNIT 1	PEAKER	48

Generation Plant	Plexos Res ID	Resource Type	Max Capacity
	OGE_1_UNIT 2	PEAKER	48
MMC - Electrovest (Otay)	OTAY_6_PL1X2	PEAKER	100
Miramar 2	Q121_1_UNIT	PEAKER	46
Cabrillo	CBRLLO_6_PLSTP1	BIOMASS	5
Carlton Hills	CHILLS_1_SYCLFL	BIOMASS	2
Carlton Hills	CHILLS_7_UNITA1	BIOMASS	2.5
Capistrano	CPSTNO_7_PRMADS	BIOMASS	6.1
East Gate	EGATE_7_NOCITY	BIOMASS	3.8
Mesa Heights	MSHGTS_6_MMARLF	BIOMASS	7.6
Otay Landfill I	OTAY_6_UNITB1	BIOMASS	5
Otay Landfill II	OTAY_7_UNITC1	BIOMASS	5
San Marcos Landfill	SMRCOS_6_UNIT 1	BIOMASS	1.8
Naval Station	DIVSON_6_NSQF	COGEN	47
Goalline	ESCO_6_GLMQF	COGEN	49.8
North Island	NIMTG_6_NICOGN	COGEN	5
	NIMTG_6_NIQF	COGEN	33
NTC Point Loma Steam Turbine	PTLOMA_6_NTCCGN	COGEN	2.58
NTC Point Loma	PTLOMA_6_NTCQF	COGEN	22
Sampson	SAMPSN_6_KELCO1	COGEN	25
Chicarita	CCRITA_7_RPPCHF	HYDRO	2
Lake Hodges	LKHODG_1_UNIT 1	HYDRO	20
	LKHODG_1_UNIT 2	HYDRO	20
Mission/Murray	MSSION_2_QF	MULTIPLE	3
Kumeyaay	CRSTWD_6_KUMYAY	WIND	50
		Total	4008

Exhibit 4

2015 TE/VS Consumer Benefits	B3	S3	Delta (S3-B3)
Δ Load Market Cost (LMC)	$9,585,379,425	$9,506,225,312	-$79,154,113
Δ Marginal Loss Surplus (MLS)	$254,985,049	$257,313,473	$2,328,424
Consumer Benefit (BTL) BTL = -1 * Δ(LMC - MLS)			$81,482,537

2015 TE/VS Societal Benefits	B3	S3	Delta (S3-B3)
Consumer Benefit (BTL)			$81,482,537
Δ Congestion Revenue (CR)	$113,749,679	$93,546,988	-$20,202,691
Δ Production Surplus (PS)	$6,813,262,328	$6,779,904,389	-$33,357,939
Societal Benefit SB = BTL - ΔCR + ΔPS			$68,327,289

B3 = Basecase

S3 = TE/VS Project in-service w/Path 42 upgrades

Exhibit 5

2015 TE/VS Consumer Benefits	B3	S2	Delta (S3-B2)
Δ Load Market Cost (LMC)	$9,585,379,425	$9,452,411,420	-$132,968,005
Δ Marginal Loss Surplus (MLS)	$254,985,049	$255,754,837	$769,788
Consumer Benefit (BTL) BTL = -1 * Δ(LMC - MLS)			$133,737,793

2015 TE/VS Societal Benefits	B3	S2	Delta (S3-B2)
Consumer Benefit (BTL)			$133,737,793
Δ Congestion Revenue (CR)	$113,749,679	$95,782,169	-$17,967,511
Δ Production Surplus (PS)	$6,813,262,328	$6,778,216,888	-$35,045,440
Societal Benefit SB = BTL - ΔCR + ΔPS			$116,659,863

B3 = Basecase

S2 = TE/VS Project in-service w/LEAPS

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of

"DIRECT TESTIMONY OF CHRISTINE VANGELATOS ON BEHALF OF THE NEVADA HYDRO COMPANY"

on all known parties to A.10-07-001 by transmitting an electronic mail message with the document attached to each person named in the official service list who provided an electronic mail address.

Executed this 30th day of November, 2010 at Washington, D.C.

/s/ Patrick L. Morand
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