ATTACHMENT 4

CALIFORNIA ISO

Potential Economic Benefits to California Load from Expanding Path 15 – Year 2005 Prospect

Prepared by
Keith Casey, Ph.D.
and Jing Chen, Ph.D.

Department of Market Analysis
California Independent System Operator

September 24, 2001

TABLE OF CONTENTS

Executive Summary

This analysis supplements a larger study[1] (hereafter referred to as the ISO's "main study") completed by the ISO that evaluates the cost and benefits of building additional transmission capacity on Path 15 in year 2005. The ISO's main study looks at two potential benefits from upgrading Path 15: 1) net-cost savings to load and 2) reduction in re-dispatch costs. While the ISO's main study provides some important information on the potential economic benefits from upgrading Path 15, its findings are based on the premise of a perfectly competitive electricity market where prices reflect marginal cost and no single supplier has the ability to manipulate prices. Under these assumptions, the results of the main study indicate that significant economic benefits from upgrading Path 15 only arises under a worst case supply scenario that assumes a drought year and a "low" new generation scenario in which very little new generation is built in northern California and the Pacific Northwest.

In this report we go beyond the fundamental assumption of a perfectly competitive market and examine the extent to which suppliers may be able to exercise market power in northern California (NP15) in year 2005 under various scenarios of new generation investments and hydro conditions. We utilize the same supply scenarios used in the ISO's main study and provide additional scenarios relating to the availability of Existing Transmission Contracts (ETC) and the State's long-term power contracts. We then examine the extent to which market power is mitigated through upgrading Path 15. By providing addition import capability into northern California, the expansion of Path 15 mitigates the ability of suppliers to exercise market power.

The results of this analysis indicate there is a potentially significant additional economic benefit from upgrading Path 15 in terms of mitigating costs associated with market power in northern California. Specifically, this study finds that under a number of reasonable supply scenarios in year 2005, the potential annual cost benefits to load in northern California (NP15) range from $208 million to $1.3 billion, assuming a dry hydro season and other reasonable assumptions relating to the amount of new generation investment and whether the State's long-term power contracts remain in effect through 2005.

The projected cost of expanding Path 15's transmission capacity is estimated to be approximately $300 million[2]. The results of this analysis, particularly those presented in

[1] The larger study conducted by the ISO is titled "Path 15 Expansion Economic Benefit Study: Phase II – Year 2005 Prospect, September 2001".

[2] This is the cost reported in PG&E's conditional application to the CPUC for a Certificate of Public Convenience and Necessity (CPCN) authorizing the construction of the Path 15 expansion. This cost estimate is based on a "full" path 15 reinforcement that includes looping a 500 kv line and having series compensation on the line. A second option exists to not add series compensation initially and to not loop the line in. The cost of this option is estimated to be at $220 million.

Tables 5-6, suggest that the potential cost benefits to load in NP15 from expanding Path 15 will likely equal or exceed the project cost in one to three years.

The specific approach used in this analysis is to: 1) measure the extent to which suppliers may be able to exercise market power in northern California (NP15) in year 2005 under various supply scenarios, 2) calculate the cost impact this market power may have to northern California load, and 3) estimate the extent to which the ability to exercise market power and its corresponding cost impact to load is mitigated by the proposed transmission expansion of Path 15.

A Residual Supply Index (RSI) is used in this study to measure market power. The RSI is a measure of whether the largest seller in a particular market is pivotal in the sense that total market demand could not be met absent that seller's supply. An RSI value less than 100% would indicate the largest supplier is pivotal and thus would have the ability to set the market clearing price. When RSI is marginally higher than 100%, the largest supplier, or a few of the large suppliers jointly, still have significant market power. In this analysis, we calculate hourly RSI values for northern California (NP15) under each supply scenario in 2005 and with and without the proposed expansion of Path15 to capture how the potential added transmission capacity would mitigate market power. To estimate the cost impact of market power, we first examine how market power has historically impacted market prices using estimated RSIs and price-cost markups in year 2000.

Price-cost markups measure the percent by which actual real-time hourly energy prices exceed estimated prices assuming a perfectly competitive market in Year 2000. Hourly competitive base line prices are estimated based on year 2000 supply and demand conditions, spot market gas prices, emissions costs, unit heat rates, and other factors that could be expected to affect system marginal costs under competitive market conditions. Actual hourly prices for year 2000 are comprised of a weighted average of the California Power Exchange's day-ahead energy prices and ISO's real-time market prices. Using the year 2000 data, regression analysis is used to estimate the effect RSIs have on price-cost markups. The estimated coefficients from this analysis are used to project price-cost markup for the RSI estimates in 2005. Finally, the computed price-cost markups are applied to the projected competitive market prices under each scenario and projected net-load to produce the costs due to exercising market power with and without the Path 15 expansion. The total cost benefits to NP15 load for year 2005 are the sum of the differences in these costs (with and without the Path 15 expansion) for all hours in 2005.

An important component in the calculation of the cost benefits to NP15 load is the amount of projected net-load that could be potentially subject to market power. Two scenarios are used in this study to estimate projected net load. The first scenario assumes all the projected load not covered by IOU generation is subject to market power. The second scenario factors in the long-term energy contracts secured by the State of California and estimates the projected net-load by subtracting these contracts along with IOU generation from the projected load forecast. Whether the State's long-term contracts will remain in effect through 2005 remains to be seen. If these contracts are at some point deemed to be substantially disproportionate to prevailing market conditions over the next few years, the State may seek to terminate or renegotiate the terms of these contracts. Conducting a cost benefit analysis with and without the State's long-term power contracts provides some reasonable bookends to the potential market power cost impacts. This analysis finds that even if all of the State's long-term energy contracts remain in place in 2005, there are potentially significant cost benefits to NP15 load from upgrading Path 15.

1. Introduction

This analysis supplements a larger study[3] (hereafter referred to as the "main study") completed by the ISO that evaluates the cost and benefits of building additional transmission capacity on Path 15 in year 2005. The main study looks at two potential benefits from upgrading Path 15: 1) net-cost savings to load and 2) reduction in re-dispatch costs. While the ISO's main study provides some import information on the potential economic benefits from upgrading Path 15, its findings are based on the premise of a perfectly competitive electricity market where prices reflect marginal cost and no single supplier has the ability to manipulate prices.

In this report we question this fundamental premise by examining the extent to which suppliers may be able to exercise market power in northern California (NP15) in year 2005 under various scenarios of new generation investments and hydro conditions. To provide for some comparability of results, we utilize the same supply scenarios used in the ISO's main study and provide and provide additional scenarios relating to the availability of Existing Transmission Contracts (ETC) and the State's long-term power contracts. We then examine the extent to which market power is mitigated through upgrading Path 15. By providing addition import capability into northern California, the expansion of Path 15 mitigates the ability of suppliers to exercise market power. The results of this analysis indicate there is a potentially significant additional economic benefit from upgrading Path 15 in terms of mitigating costs associated with marketing power in northern California.

Section 2 of this report describes the basic analytical framework used in this analysis. In Section 3, we describe the 24 different scenarios used in this analysis. The scenarios represent different assumptions on additional new generation, hydro conditions, the availability of Existing Transmission Contracts (ETC) on Path15 and COI, and whether or not Path 15 is upgraded. This section also provides detailed information about the Monte Carlo simulations used in this analysis to capture the uncertainty associated with key supply variables. Results and conclusions are provided in Section 4.

2. Basic Analytical Framework

Overview of the Analytical Approach Used in this Study

The primary objective of this analysis is to 1) measure the extent to which suppliers may be able to exercise market power in northern California (NP15) in year 2005 under various supply scenarios, 2) calculate the cost impact this market power may have to northern California load, and 3) estimate the extent to which the ability to exercise market power and its corresponding cost impact to load is mitigated by the proposed transmission expansion of Path 15. A Residual Supply Index (RSI) is used in this study to measure market power.

---

[3] The larger study conducted by the ISO is titled "Path 15 Expansion Economic Benefit Study: Phase II – Year 2005 Prospect, September 2001".

The RSI is a measure of whether the largest seller in a particular market is pivotal in the sense that total market demand could not be met absent that seller's supply.

RSI = (Total Supply – Largest Seller's Supply)/(Total Demand)

An RSI value less than 100% would indicate the largest supplier is pivotal and thus would have the ability to set the market clearing price. When RSI is marginally higher than 100%, the largest supplier, or a few of the large suppliers jointly, still have significant market power.[4]

In this analysis, we calculate hourly RSI values for northern California (NP15) under each supply scenario and with and without the proposed expansion of Path15 to capture how the potential added transmission capacity would mitigate market power. To estimate the cost impact of market power, we first examine how market power has historically impacted market prices using estimated RSIs and price-cost markups[5] in year 2000. Using the year 2000 data, regression analysis is used to estimate the effect RSIs have on price-cost markups. The estimated coefficients from this analysis are used to project price-cost markup for the RSI estimates in 2005. Finally, the computed price-cost markups are applied to the projected competitive market prices under each scenario and forecasted load to produce the costs due to exercising market power with and without the Path 15 expansion. The total economic benefits for year 2005 are the sum of the differences in these costs (with and without the Path 15 expansion) for all hours in 2005.

This analysis is conducted for 24 different scenarios. The scenarios include 2-different hydro scenarios (dry, normal) 3-new generation scenarios for NP15 (low, medium, high), a with and without Existing Transmission Contracts (ETC) for Path 15 scenario, and a with and without Path 15 expansion scenario. In addition, because supply availability is highly variable and uncertain, we use Monte Carlo simulations for hydro availability, outage rates for existing thermal generation, and available ATC and TTC on Path15 and COI. Section 3 provides a detailed description of the methodology and data used in the Monte Carlo simulations.

[4] Based on previous analysis, when RSI is greater than 120%, the system wide price cost mark-up is insignificant on average.
[5] Price-cost markups measure the percent by which actual real-time hourly energy prices exceed estimated prices assuming a perfectly competitive market in Year 2000.

RSI Calculation

As noted above, there are three components to the RSI (Total Supply (TS), Largest Single Supplier (LSS) and Total Demand (TD)). Each of these components are described in detail below.

1. Total Demand (TD)

If the Path 15 expansion were approved, the upgrade would not be completed until 2005. Thus, this analysis uses hourly forecasted demand data for congestion zone NP15 in 2005. These are the same demand data used in the ISO's main study. A description of how these forecasted demand data are derived is provided in a technical appendix to the ISO's main study. The RSI analysis uses these demand data plus a 10 percent margin to reflect demand for operating reserve and regulation capacity.

$$TD_t = (1.1)*\text{NP15 Forecasted Demand}_t$$

Where *t* denote the particular hour in year 2005.

2. Total Supply

Total Supply in the NP15 zone in each hour of Year 2005 is comprised of five components:

A) Existing generation
   A1-existing thermal generation capacity in NP15 (including PG&E QFs, and thermal capacity owned by Duke and Mirant)
   A2-hourly PG&E available hydro capacity
   A3-hourly available generation from all other misc. generators (mainly hydro)
   A4-hourly generation capacity from Calpine's geothermal units
   A5-expected (scheduled or forced) outages for existing thermal generation
B) Expected new generation capacity in NP15
C) Expected retirement of existing generation capacity
D) Expected import supply to NP15 from the Pacific Northwest (COI)
E) Hourly import capability to NP15 on Path15 (both with and without upgrade)[6] measured either by Available Transmission Capacity (ATC) or Total Transmission Capacity(TTC)[7]

For a given supply scenario, Total Supply (TS) for each hour (t) is calculated as:

$$TS_t = (A1_t+A2_t+A3_t+A4_t-A5_t)-C_t + .897*B_t + D_t + E_t$$

---

[7] ATC is equal to the amount of capacity available for new firm use. This is different than Total Transmission Capacity, which is equal to ATC plus capacity reserved for Existing Transmission Contracts.

New generation capacity in NP15 (B_t) is multiplied by .897 to reflect an assumed outage rate of 10.3%, which is the same outage rate used in the ISO's main study.

3. Largest Single Supplier (LSS)

Our initial approach for determining the available capacity of the largest single supplier in NP15 (LSS) was to compare the projected available capacity of each supplier in each hour and select the maximum value, excluding PG&E[8]. For each hour, a supplier's available capacity is equal to the sum of its existing and projected new generation in NP15 less estimated outages. Outages of each supplier's existing generation are based on random draws (100 draws for each hour) of its actual outages in year 2000. Outages for new generation capacity are based on a 10.3% outage rate, which was the outage rate used in the ISO's main study. However, in all three new generation scenarios, Calpine's projected available capacity (less a 10.3% outage rate for projected new thermal capacity) was found to be larger than any other supplier's total capacity assuming a 0% outage rate for their capacity[9]. This result indicates Calpine will always be the largest single supplier, regardless of the level of outages of other suppliers. Thus, the LSS for each hour is simply a sum of Calpine's geothermal generation in 2000 and proposed new generation under three different scenarios for all hours in 2005, adjusted by a factor of 0.897 to account for scheduled and forced outages of newly built thermal facilities.

Price-Cost Markup Calculation

To estimate a relationship between RSIs and price-cost markups, estimated price-cost markups for year 2000 are regressed against estimated RSIs and actual system loads for year 2000. Estimated price-cost markups for year 2000 are calculated using actual energy prices for year 2000 (weighted average of PX day-ahead and ISO real-time energy prices) and estimated competitive baseline prices. Estimated competitive baseline prices are calculated based on year 2000 supply and demand conditions, spot market gas prices, emissions costs, unit heat rates, and other factors that could be expected to affect system marginal costs under competitive market conditions[10]. To account for seasonal and time

[8] PG&E is excluded because its ability to strategically withhold capacity from the market is limited by its run of the river hydro facilities and a significant amount of must take QF resources. In addition, as a net buyer in NP15, PG&E does not have an incentive to exercise market power.

[9] Calpine's supply consists only of new thermal generation and geothermal generation, which has very little hourly variation in availability.

[10] A complete description of the methodology used by the ISO Department of Market Analysis to calculate competitive baseline energy prices can be found in "Further Analyses of the Exercise and Cost Impacts of Market Power in California's Wholesale Energy Market", March 2001, Prepared by Dr. Eric Hildebrandt, Department of Market Analysis. Submitted as Attachment B to the ISO's Comments on FERC Staff's Recommendations on Prospective Market Monitoring and Mitigation for the California Wholesale Market, March 22. 2001.

of day variation, the year 2000 data is separated into four seasons (May-Oct (Peak & Off-Peak Hours) and Nov-Apr (Peak & Off-Peak Hours) and separate regressions are done for each period. Both RSIs and actual system loads are assumed to have a non-linear relationship with market prices such that as RSIs decline or actual system loads increase market prices increase at an increasing rate. However, RSIs and actual system loads are assumed linear with respect to price-cost markups, which are expressed as a Lerner Index (i.e. (price-marginal cost) divided by price).

$$\text{Lerner Index } ((P_t - C_t)/P_t) = a + b*RSI_t + c*Load_t$$

This specification assumes that a decline in RSI or an increase in system load ($Load_t$) will result in a higher percent mark-up over the estimated competitive price.

The estimated regression parameters are then used to compute price-cost markups in 2005 based on estimated RSIs and projected loads for NP15. The computed price-cost markups are then applied to the estimated hourly competitive prices for 2005 derived from the ISO's main study[11] to derive the total cost impact to NP15 load.

Cost Benefit to NP15 Load from Path15 Expansion

The cost to NP15 load under the scenario where Path 15 is not expanded (the "status quo" scenario) can be represented by the following equation:

$$Cost_{sq,t} = P_{sq,t}*(1+ PCM_{sq,t})*Load_t$$

Where $P_{sq,t}$ is the projected competitive price in NP15 under the status quo (sq) and $PCM_{sq,t}$ is the estimated price-cost markup under the status quo. Projected $Load_t$ is equal to the forecasted load in NP15 for 2005 less estimated generation supplied by PG&E. Similarly, the cost to NP15 load under the scenario where Path 15 is expanded (the "with upgrade" scenario) can be represented by the following equation:

$$Cost_{wu,t} = P_{wu,t}*(1+ PCM_{wu,t})*Load_t$$

Where $P_{wu,t}$ is the projected competitive price in NP15 under the "with upgrade" scenario (sq) and $PCM_{wu,t}$ is the estimated price-cost markup under the "with upgrade" scenario.

The cost benefit to NP15 load from the Path 15 expansion is the difference between these two equations.

$$\text{Cost Benefit}_t = Cost_{wu,t} - Cost_{sq,t}$$

This difference can be decomposed into two components: 1) benefits due to a lower competitive NP15 zonal price and 2) benefits from mitigating market power.

[11] For more details about the derivation of competitive baseline prices for each scenario, refer to technical appendix of the ISO's main report.

$$\text{Cost Benefit}_t = \underbrace{(P_{sq,t} - P_{wu,t})*\text{Load}_t}_{\textbf{Benefits due to cheaper competitive NP15 zonal prices}_t} + \underbrace{(PCM_{sq,t}*P_{sq,t} - PCM_{wu,t}*P_{wu,t})*\text{Load}_t}_{\textbf{Benefits due to mitigating market power}_t}$$

The projected competitive prices without (status quo) and with the Path 15 expansion are derived from the scenario simulations completed in the ISO's main study. Projected load (Load_t) is the California Energy Commission's forecasted load for NP15 less the load served by PG&E's own generation (i.e. PG&E's net-short position).

The benefits due to mitigating market power can be further decomposed into two parts: 2a) benefits from decreases in competitive prices while the price-cost markups are fixed and 2b) the benefits from decreases in price-cost markups while the prices are fixed.

$$\textbf{Market Power Mitigation Benefits}_t = \underbrace{(PCM_{wu,t}(P_{sq,t} - P_{wu,t}))}_{\textbf{Benefits from decreases in competitive prices holding the price-cost markup fixed}} + \underbrace{(PCM_{sq,t} - PCM_{wu,t})P_{sq},t}_{\textbf{Benefits from decreases in price-cost markups holding the price fixed}}$$

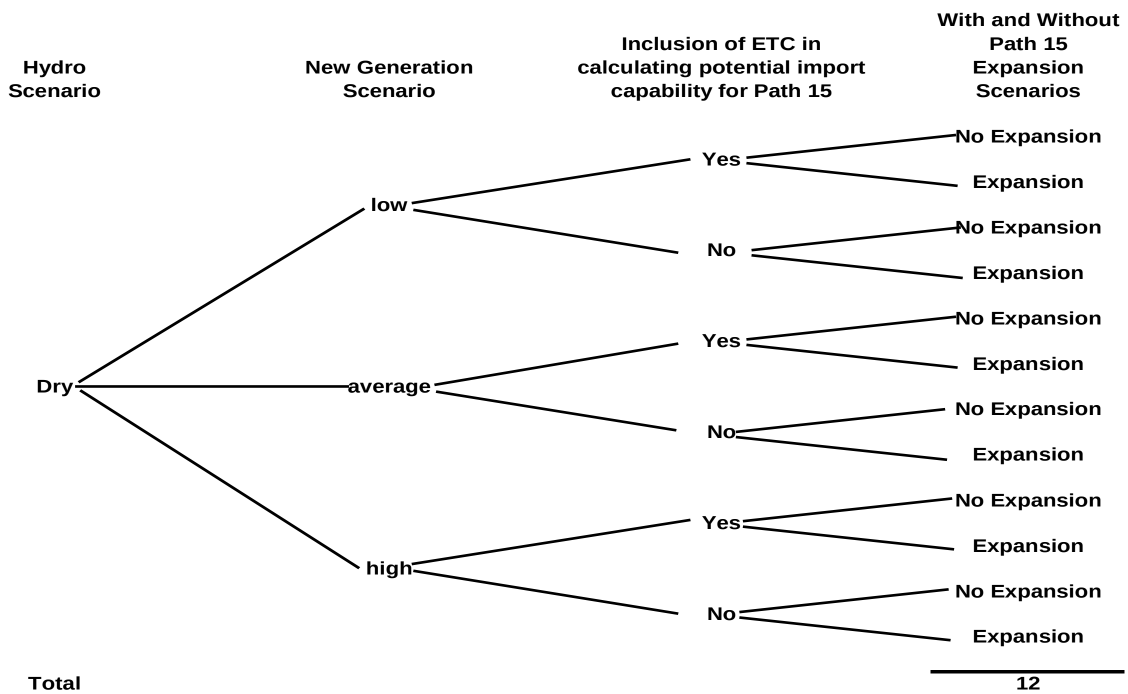
Aggregating all hourly benefits in 2005 produce the total economic benefits to NP15 load from upgrading Path 15. This results in 12 sets of estimated benefits from upgrading Path15 in mitigating marketing power corresponding to different hydro, ETC release, and proposed new generation conditions.

3. Description of Scenarios and Monte Carlo Simulations

Scenarios

Due to the high degree of uncertainty associated with proposed new generation, hydro conditions, and available transmission capacity a number of different supply scenarios are used in this analysis. In addition, two different scenarios are done relating to the availability of existing transmission contracts (ETC) on COI and Path 15. Existing Transmission Contracts represent transmission capacity on COI and Path 15 that is reserved to certain parties under contractual arrangements that pre-date the ISO. This capacity is not available to the forward markets but any unused ETC is available for market use in real-time. Presumably, California will develop forward spot markets for energy by 2005 and if unscheduled ETC on Path 15 and COI remains unavailable to the forward markets, it may exacerbate market power in NP15. Thus, this analysis provides for two scenarios, one where ETC is released to the market and one where it is not. Figure 1 provides a schematic of the 12 scenarios stemming from a dry hydro scenario. The same 12 scenarios are also applied for a normal hydro year.

Figure 1: Scenario Schematic for Dry Hydro Scenario



There are three new generation scenarios where the likelihood of new generation projects actually being built in NP15 is based on the status proposed projects have before the California Energy Commission as of August 2001. Table 1 summarizes these scenarios.

Table 1: New Generation Scenarios for NP15

Scenario	Additional New Capacity	Status before the CEC
1	Average	"approved", "pending", and "peaker"
2	Low	"approved", "peaker"
3	High	"approved", "pending", "peaker", and "announced"

To capture yearly variations in hydro conditions, two hydro scenarios "normal" and "dry" are considered. For the normal hydro year scenario, hourly hydro availability for NP15 is based on metered hydro data for year 2000 and hourly hydro imports on COI is similarly based on actual metered flows on COI for year 2000. For the dry hydro year, to calculate hydro availability for NP15 we applied hourly adjustment factors to the metered hydro data for year 2000. These adjustment factors were provided by PG&E and represent an approximate 1 in 10 year drought condition. These factors also change over different seasons to account for different water management approaches in a dry hydro year. To estimate hydro availability from the Pacific Northwest under a dry hydro year scenario, we used actual flow data on COI for water year 93-94, which according to data provided by the Northwest Power Pool best represents a 1 in 10 year drought condition. The 1993-94 actual flow data on COI was provide by BPA. A more detailed description of the data and methodology used to calculate hydro availability under the dry hydro year scenario can be found in the ISO's main report.

Monte Carlo Simulations

In addition to these 24 scenarios, we also applied Monte Carlo analysis to account for the uncertainty and variability of certain key supply variables such as hydro generation, outage rates for existing thermal generation, and available ATC and TTC on Path15 and COI for each hour. Monte Carlo draws are used for two reasons. First, these variables are very volatile within a year. A one time observation for a particular hour in 2000 is more likely to be a realization from a random distribution, and may not be very representative for the same hour in year 2005. Thus, 100 repetitive draws from the same distribution might have a better prediction of what is going to happen for that same hour in 2005. Second, as mentioned earlier, the relationship between price-cost markup and RSI is nonlinear, especially when RSI is very low and market power becomes an important issue. Price-cost markup computed using average RSI (that in turn uses data such as average outage rates for the same month in 2000) will be biased because of this nonlinearity and will tend to underestimate the price impact of market power . However, a hundred random draws for these variables will produce 100 RSIs and corresponding price-cost markups for each hour. The mean of these 100 price-cost markups would produce a more precise estimate of potential price-cost markup for that particular hour in 2005.

The various variables for which Monte Carlo simulations were applied and the data and methodology used in these simulations are described below. Recall that total Supply in the NP15 zone in each hour of Year 2005 is comprised of five components:

A) Existing generation

A1-existing thermal generation capacity in NP15 (including PG&E QFs, and thermal capacity owned by Duke and Mirant)

A2-hourly PG&E available hydro capacity

A3-hourly available generation from all "other NP15 hydro" (i.e. WAPA, SMUD etc.)

A4-hourly generation capacity from Calpine's geothermal units

A5-expected (scheduled or forced) outages for existing thermal generation

B) Expected new generation capacity in NP15

C) Expected retirement of existing generation capacity

D) Expected import supply to NP15 from the Pacific Northwest (COI)

E) Hourly import capability to NP15 on Path15 (both with and without upgrade)[12] measured either by Available Transmission Capacity (ATC) or Total Transmission Capacity(TTC)[13]

For a given supply scenario, Total Supply (TS) for each hour (t) is calculated as:

$$TS_t = (A1_t+A2_t+A3_t+A4_t-A5_t)-C_t + .897*B_t + D_t + E_t$$

Monte Carlo Simulations for NP15 Hydro Availability (A2, A3)

To capture the within year variation and uncertainty of NP15 hydro supplies we conducted 100 Monte Carlo draws for each hour from a data set comprised of year 2000 hourly metered output for PG&E hydro facilities in NP15 (A2) and an "Other Hydro" category representing miscellaneous hydro output from various other entities located in NP15 such as SMUD and WAPA (A3). As described in the previous section, these values were adjusted downward for the dry-hydro scenario. To account for large differences in hydro power supply across the run-off season and the storage season, we divide the whole sample into two seasons, one representing the run-off season (May to October) and one representing the storage season (Nov-April). To account for different water management practices during the peak hours and off-peak hours, we further divided these two samples into peak and off-peak hour periods.

Monte Carlo Simulations for Outages from Existing Thermal Generation (A5)

To estimate forced and scheduled outages from existing thermal generation in NP15 (A5), we compute hourly outages for each major thermal generation owner through Monte Carlo simulations that draw from the unit owner's actual reported daily outages for 2000. Actual reported outages for each owner are separated into two seasons, a

[13] ATC is equal to the amount of capacity available for new firm use. This is different than Total Transmission Capacity, which is equal to ATC plus capacity reserved for Existing Transmission Contracts.

maintenance season (Nov-April) when outages are generally much higher and a non-maintenance season (May-Oct) when outages are generally much lower.

Monte Carlo Simulations for Import Capability on COI and Path 15 (D, E)

The amount of potential import into NP15 zone is a significant determinant of the total supply availability. There are two major transmission paths into and out of the NP15 zone, Path 15 and COI. As previously discussed, this analysis uses two scenarios relating to the availability of ETC on these two paths. Under the scenario of not releasing ETC, the estimated ATC is used to capture transmission capacity, while the estimated actual TTC (which is sum of ATC and ETC) is used to represent the total transmission capacity under the scenario where ETC is released.

Under each ETC scenario, two additional scenarios are done relating to the available capacity on Path 15, 1) the status quo scenario and 2) the "with upgrade" scenario. Under the "status quo" scenario and no release of ETC, actual hourly ATC values for 2000 are used as base values to conduct 100 Monte Carlo draws to project ATC values for 2005 in each hour. Under the "with upgrade" scenario, the additional 1400 MW of transmission capacity from upgrading Path 15 is added to the hourly ATC values, adjusting for hourly de-rates. For instance, if for a particular hour, the TTC is only 1975 MW, half of maximum capacity, we assume that only half (700 MW of the proposed 1,400 MW upgrade) of added capacity is available for that particular hour and this amount is added to the ATC under the "with upgrade and no release of ETC scenario". Under the scenario of releasing ETC, actual TTCs are used and same de-rates are applied to the 1,400 MW of proposed new capacity.

The current maximum capacity of Path 15 is 3950 MW, but this capacity can vary hourly due to many factors. ATC might also change significantly even the actual TTC are similar over different hours. To estimate ATC and TTC for each hour in 2005, we conduct 100 Monte Carlo draws from a pool of actual ATC and TTC data on Path 15 in the same month in year 2000. For example, to project ATC and TTC in hour 8 on August 15th, 2005, we conduct 100 draws from observed hourly ATC and TTC data in August 2000.

We essentially followed the same procedure to simulate the potential import (or export) from COI. There are two major adjustments, however. First, to account different power transmission patterns in COI between normal hydro year and bad hydro year, we use hourly-metered import data in 2000 as base values for normal hydro year and a different set of data for a lower hydro year. Second, we also take into account of proposed new generation in Northwest region and COI transmission capacity which, similar to proposed new generation in NP15 region, are projected under three scenarios. The exact formulas for COI transmission under different scenarios are listed in Appendix I of the ISO's main report. To project ATC and TTC on COI at a specific hour in 2005, we also conduct 100 Monte Carlo draws from data in the same month in 2000 under different scenarios.

Comments on other Supply Variables (A4, C)

For power supplied by geothermal generation (A4), we found generation has been largely stable according to data observed in 2000. It means that unexpected forced and scheduled output might not affect generation as much as thermal generations. Thus, we just use generation from Calpine geothermal generation in 2000 to predict supply in 2005. The expected retirement data (C) is obtained from California Energy Commission.

Summary of Monte Carlo Simulations

All of the Monte Carlo Simulations described above result in 100 random draws for each variable for each hour. All of these data are merged into a single data set that is comprised of 878,400 records (i.e. 366 days*24 hours*100 random draws per hour) and RSIs and Price-cost markups are calculated for each record. From these data, an average Price-cost markup and average supply variables are calculated for each hour. The cost impacts to NP15 load are then calculated from these data based on the methodology described in Section 2.

4. *Results and Conclusion*

Regression Results

Table 2 provides a summary of the regression results where estimated Lerner Indexes[14] are regressed against actual system loads and estimated RSIs using year 2000 data.

$$\text{Lerner Index}_t = a + b^* \ RSI_t + c^*Load_t + \varepsilon_t$$

Table 2: Lerner Index and RSI Regression Results

Peak Season (May-Oct 2000)				
	Peak Hours		Off-Peak Hours	
Variables	Coefficient	t-stat	Coefficient	t-stat
Intercept	1.26	12.58	2.31	16.38
RSI	-1.54	-27.20	-2.24	-33.17
Actual Load	2.19E-05	15.85	2.01E-05	7.07
R-Squared	0.63		0.58	
Number of Observations	2,522		1,886	
Off-Peak Season (Nov-1999 - Apr 2000)				
	Peak Hours		Off-Peak Hours	
Variables	Coefficient	t-stat	Coefficient	t-stat
Intercept	1.48	10.96	1.59	4.25
RSI	-1.20	-21.74	-1.95	-12.77
Actual Load	1.93E-06	0.80	4.40E-05	6.03
R-Squared	0.42		0.34	
Number of Observations	2,494		1,840	

As discussed in Section 2, separate regressions are run for two different time periods, a Peak Season defined as May-Oct 2000 and an Off-Peak Season defined as Nov 1999 – Apr 2000[15] and separate regressions are done within both of these seasons for Peak and Off-Peak hours for a total of 4 regressions. These results indicate that in all four periods there is a statistically significant relationship between the Lerner Index and RSIs and

[14] The Lerner Index uses the market price as the denominator when calculating markup, i.e., price-cost markup = (price – cost) / price.

[15] November and December 1999 data were used in place of the same months in year 2000 because because of the extreme price volatility during this period.

actual system loads. These two variables explain over 58% of the variation in the Lerner Indexes during the peak season and over 34% of the variation in the off-peak season (see R-Squared values in Table 3). Moreover, the signs of the estimated coefficients are as expected. A negative coefficient on RSIs indicates that smaller RSIs (i.e. a more dominant market share by the largest supplier) correspond to higher Lerner Indexes (i.e. higher price-cost markup). A positive coefficient value for actual system loads indicates that Lerner Indexes increase with actual system loads (i.e. markets tend to become less competitive as actual system loads increase).

Cost Benefit to NP15 Load Results (Excluding Long-term Power Contracts)

Table 3 summarizes the estimated results under the 24 different scenarios. The top half of the table shows the results under the normal hydro year scenario for the various new generation scenarios and whether ETC is assumed available or not. Under the normal hydro scenario, the estimated annual cost benefits to NP15 load range from $19 million to $342 million depending on the particular scenario. Whether ETC is assumed available or not has a big effect on the potential benefits to load. If ETC on COI and Path 15 is counted as available capacity, the annual cost benefits to NP15 load are much smaller but still significant, ranging form approximately $19 million to $115 million, depending on whether less or more new generation is built in California, respectively. If ETC on COI and Path 15 is not counted as available capacity, the annual cost benefits to NP15 load are much larger, ranging from approximately $85 million under the high new generation scenario to $342 million under the low new generation scenario. Table 3 also breaks the total cost benefit into several components. Cost savings due to the effect the Path 15 expansion has in reducing market power is shown in row C. It can be further decomposed into two components, a price effect (row C1) and a price-cost markup effect row (C2). Recall from Section 2 that the cost benefit to NP15 Load can be decomposed according to the following equations.

$$\text{Cost Benefit}_t = \underbrace{(P_{sq,t} - P_{wu,t})*\text{Load}_t}_{\substack{\textbf{Benefits due to cheaper}\\ \textbf{competitive NP15 zonal prices}_t\\ \textbf{(D)}}} + \underbrace{(PCM_{sq,t}*P_{sq,t} - PCM_{wu,t}*P_{wu,t})*\text{Load}_t}_{\substack{\textbf{Benefits due to mitigating}\\ \textbf{market power}_t\textbf{ (C)}}}$$

$$\begin{array}{c}\textbf{Market Power}\\ \textbf{Mitigation Benefits}_t\\ \textbf{(C)}\end{array} = \underbrace{(PCM_{wu,t}(P_{sq,t} - P_{wu,t}))}_{\substack{\textbf{Benefits from decreases in}\\ \textbf{competitive prices holding the}\\ \textbf{price-cost markup fixed}\\ \textbf{(C1)}}} + \underbrace{(PCM_{sq,t} - PCM_{wu,t})P_{sq,}t}_{\substack{\textbf{Benefits from decreases in}\\ \textbf{price-cost markups holding the}\\ \textbf{price fixed}\\ \textbf{(C2)}}}$$

As can be seen in Table 3, the primary cost benefit comes from the reduction in the price-cost markup and it makes up most of the total cost benefit to load under the normal hydro scenario.

The results for the dry-hydro year scenario are shown in an identical format in the bottom half of Table 3. These results clearly show a much larger cost benefit to NP15 load under all scenarios of new generation and release of ETC. Under the dry-hydro scenario, total annual cost benefits to NP15 load range from $37-$307 million under the inclusion of ETC scenario and from $148 million to near $1.3 billion under the no release of ETC scenario.

While the focus of this study is on the economic benefits to NP15 load from upgrading Path 15, the upgrade will also have a cost impact to load in southern California (SP15). Upgrading Path 15 will have two opposing cost impacts to SP15 load. First, the upgrade will help to reduce costs to load in SP15 through mitigating the ability of suppliers to exercise market power. However, this benefit will be offset to some extent by the fact that market prices in SP15 will tend to increase because more generation will be producing in SP15 to serve northern California load. Though this study does not examine the potential cost benefits to SP15 load from expanding Path 15 in terms of mitigating market power, it does include an estimate of the cost impact to SP15 load from higher competitive prices. This impact is shown as row E in Table 4 and demonstrates that the higher cost impact to SP15 load from expanding Path 15 is significantly less than the cost benefit to NP15 load. The net cost benefit to both NP15 and SP15 load is shown in the final row of Table 4 for both the “Normal” and “Dry” hydro scenario.

In this particular analysis, the estimated cost benefits are based on the hourly projected net short load positions in NP15 and SP15 for 2005. These are estimated by subtracting the estimated hourly output of the IOU’s own generation from the hourly forecasted load in each zone. This difference is typically referred to as the “net-short position” of the IOUs and would be the amount subject to market power abuse absent any additional energy contracts that the IOUs or the State of California may have entered into. As is well known, the State of California has signed a number of long-term energy contracts that extend into 2010. Whether these contracts will remain in effect for their full term or will be terminated or renegotiated is unclear at this point. By not including these contracts in estimating the IOU’s net-short position, this analysis provides a worst case scenario in which the IOU’s entire net-short position is subject to shorter-term markets and the spot markets where market power can be easily exercised. To provide a best case scenario, the next section provides an analysis that subtracts the State’s long term contracts for year 2005 from the IOU’s net-short position.

Cost Benefit to NP15 Load Results (Including Long-term Power Contracts)

Table 4 provides a summary of the estimated cost savings to NP15 load from expanding Path 15 that includes the State’s long-term power contracts in calculating the IOU’s net-short position. As one might expect, the cost benefit to load from expanding Path 15 are significantly lower when one factors in the State’s long-term contracts. Under a normal hydro year scenario, the annual benefits to NP15 load range from $52-$213 million when ETC is excluded from the available transmission capacity and range from $12 to $70 million when ETC is included. Under a dry hydro scenario, the annual benefits to NP15 load range from $96 million to $850 million in the “Excluding ETC” scenario and range from $25 to $196 million under the “Including ETC” scenario.

The cost impact to SP15 load is relatively small when the State’s long-term power contracts are applied to the IOU’s net short position. Under the normal hydro year scenario, the annual cost impact to SP15 load ranges from a negative $1.3 to 4.0 million when ETC is excluded from the available transmission capacity and ranges from negative $.25 to $1.6 million when ETC is included. In all cases, the estimated annual cost benefit to NP15 load is significantly higher than the estimated annual negative cost benefit to SP15 load. Moreover, as discussed earlier, the negative cost benefit to SP15 load is likely overstated by the fact that any cost saving from reduced market power in SP15 are not considered. The estimated cost benefit to SP15 load under the dry-hydro scenario is significantly higher than under the normal hydro scenario but like the normal hydro scenario, the costs are significantly below the estimated positive cost benefits to NP15 load, making the net-benefit quite significant.

Table 3: Summary Results of Estimated Cost Savings to NP15 Load from Path 15 Expansion (Excluding Long-term Contracts)

		Normal Hydro Year (Year 2000) $MM					
		Exluding ETC			Including ETC		
Proposed New Generation Scenarios		Medium	Low	High	Medium	Low	High
Costs Due to Excercising Marketing Power	A: Path 15 Status Quo	$494.41	$938.23	$213.42	$124.93	$297.52	$39.15
	B: Path 15 Expansion	$325.11	$613.84	$131.08	$74.86	$189.54	$21.07
C: Cost Savings to NP15 Load from Reduced Market Power from Path 15 Expansion (A-B)		$169.31	$324.39	$82.34	$50.08	$107.97	$18.08
Benefit from Price reduction (C1)		$0.42	$26.33	($0.01)	$0.05	$4.14	$0.00
Benefit rom Reduction in Price-Cost Markup (C2)		$168.89	$298.06	$82.35	$50.03	$103.83	$18.08
D: Costs Savings due to Lower Competitive Prices form Path 15 Expansion		$4.14	$17.48	$2.71	$1.61	$6.65	$0.94
Total Cost Benefit to NP15 Load (C+D)		$173.45	$341.87	$85.05	$51.68	$114.62	$19.02
E: Cost Impact to SP15 Load		-$11.79	-$16.52	-$10.45	-$3.32	-$5.91	-$2.70
Net Cost Benefit to NP15 & SP15 Load (C+D+E)		$161.66	$325.35	$74.61	$48.36	$108.71	$16.32

		Bad Hydro Year (64% of Year 2000 hydro volume) $MM					
		Exluding ETC			Including ETC		
Proposed New Generation Scenarios		Medium	Low	High	Medium	Low	High
Costs Due to Excercising Marketing Power	A: Path 15 Status Quo	$927.14	$2,231.94	$408.65	$245.74	$598.98	$83.37
	B: Path 15 Expansion	$613.88	$1,178.93	$261.82	$151.26	$360.24	$46.68
C: Cost Savings to NP15 Load from Reduced Market Power from Path 15 Expansion (A-B)		$313.26	$1,053.01	$146.83	$94.48	$238.74	$36.69
Benefit from Price reduction (C1)		$5.37	$479.95	$0.01	$1.02	$51.55	$0.00
Benefit rom Reduction in Price-Cost Markup (C2)		$307.89	$573.06	$146.82	$93.46	$187.19	$36.69
D: Costs Savings due to Lower Competitive Prices form Path 15 Expansion		$7.34	$278.69	$1.23	$2.95	$68.24	$0.59
Total Cost Benefit to NP15 Load (C+D)		$320.60	$1,331.70	$148.06	$97.43	$306.97	$37.28
E: Cost Impact to SP15 Load		-$15.52	-$27.63	-$11.42	-$6.39	-$17.79	-$3.85
Net Cost Benefit to NP15 & SP15 Load (C+D+E)		$305.08	$1,304.07	$136.64	$91.05	$289.19	$33.43

Table 4: Summary Results of Estimated Cost Savings to NP15 Load from Path 15 Expansion (Including Long-term Contracts)

		Normal Hydro Year (Year 2000) $MM					
		Exluding ETC			Including ETC		
Proposed New Generation Scenarios		Medium	Low	High	Medium	Low	High
Costs Due to Excercising Marketing Power	A: Path 15 Status Quo	$311.23	$589.12	$136.48	$79.89	$185.72	$26.23
	B: Path 15 Expansion	$206.33	$386.13	$85.15	$48.64	$118.99	$14.44
C: Cost Savings to NP15 Load from Reduced Market Power from Path 15 Expansion (A-B)		$104.90	$202.98	$51.33	$31.25	$66.73	$11.79
Benefit from Price reduction (C1)		$0.26	$19.18	($0.01)	$0.04	$3.14	$0.00
Benefit rom Reduction in Price-Cost Markup (C2)		$104.64	$183.81	$51.34	$31.21	$63.60	$11.79
D: Costs Savings due to Lower Competitive Prices form Path 15 Expansion		$1.05	$9.67	$0.37	$0.41	$3.61	$0.11
Total Cost Benefit to NP15 Load (C+D)		$105.95	$212.65	$51.70	$31.65	$70.34	$11.90
E: Cost Impact to SP15 Load		-$1.85	-$3.96	-$1.33	-$0.46	-$1.56	-$0.25
Net Cost Benefit to NP15 & SP15 Load (C+D+E)		$104.11	$208.70	$50.37	$31.19	$68.78	$11.65
		Bad Hydro Year (64% of Year 2000 hydro volume) $MM					
		Exluding ETC [a]			Including ETC		
Proposed New Generation Scenarios		Medium	Low	High	Medium	Low	High
Costs Due to Excercising Marketing Power	A: Path 15 Status Quo	$611.41	$1,454.07	$271.42	$163.13	$389.29	$57.24
	B: Path 15 Expansion	$406.90	$775.71	$175.53	$101.51	$235.03	$32.75
C: Cost Savings to NP15 Load from Reduced Market Power from Path 15 Expansion (A-B)		$204.52	$678.36	$95.89	$61.62	$154.25	$24.49
Benefit from Price reduction (C1)		$3.65	$308.30	$0.00	$0.79	$33.38	$0.00
Benefit rom Reduction in Price-Cost Markup (C2)		$200.86	$370.06	$95.89	$60.84	$120.87	$24.49
D: Costs Savings due to Lower Competitive Prices form Path 15 Expansion		$3.94	$171.85	$0.44	$1.49	$41.28	$0.20
Total Cost Benefit to NP15 Load (C+D)		$208.46	$850.21	$96.34	$63.12	$195.53	$24.68
E: Cost Impact to SP15 Load		-$3.09	-$8.50	-$1.46	-$1.37	-$6.22	-$0.48
Net Cost Benefit to NP15 & SP15 Load (C+D+E)		$205.37	$841.71	$94.87	$61.75	$189.31	$24.20

Cost Benefit Summary

Though the results presented in Tables 3 and 4 show a positive net-benefit to California load from expanding Path 15 under all the various scenarios considered, the size of the estimated benefit varies significantly under each scenario. In considering these results, policy makers will ultimately have to make their own assessment of which scenarios to weigh most heavily. However, in doing so, it is important to recognize that investments in transmission upgrades can be best thought of as an insurance policy. When the decision concerns reliability, planners typically examine worst case contingency scenarios and examine the impact these contingencies would have with and without the transmission upgrade. Given California's past experience with market power and the substantial cost impact it will ultimately have on California consumers, it would seem prudent to give heavy weight to the worst case scenarios in considering the economic impact of transmission expansions.

To that end, Table 5 provides a summary of the potential cost impacts of not upgrading Path 15 under a "reasonable" worst case scenario. This scenario is one where possible but extremely unlikely scenarios are excluded. For example, it is possible that every "announced" new generation project will be built, which is the assumption under the "high" new generation scenario, but extremely unlikely so Table 5 examines only the low and medium new generation scenarios. Similarly, it is possible that California will not experience a 1 in 10 dry hydro year from 2005 through 2015 but the probability is low (less than 35% probability) thus Table 5 examines the dry-hydro scenario. [16] In addition, the impact that ETC has on market power is quite significant. While it is true that ETC is available to the real-time market, it is not available to the forward markets. Since it is the goal of the ISO to keep its real-time market to less than 5% of total system loads and the ISO will likely implement a market design that ensures this result, most market activity will be in the forward markets where ETC is unavailable. Thus, a reasonable worst case scenario is to assume a market where ETC is unavailable. These assumptions reduce the considered scenarios to four (see Table 5).

Table 5: Reduced Scenario Summary of Cost Benefits to NP15 Load Assuming "Reasonable Worst Case" Scenarios

	State's Long-term Contract Assumptions	
New Generation Scenario	**All Contracts Remain in effect in 2005 ($MM)**	**No Contracts Remain in effect in 2005 ($MM)**
Medium	**$208**	**$321**
Low	**$850**	**$1,332**

[16] Because we assume a dry hydro year occurs, on average, once every ten years, thus, for a particular year such as 2005, the probability of not a dry-hydro year is 90%. And for a ten-year period from 2005-2014, the probability of not have a single dry-hydro year is (0.9)^10=34.8%.

Screening out the overly optimistic scenarios described above reduces the range of annual cost benefits to NP15 load from $12 to $1,332 million to $208 to $1,332 million. These results also highlight that the new generation scenario has a much more significant impact on costs than does the assumption about the State's long-term contracts. Assuming a low generation scenario causes over a 4-fold increase in cost while assuming a no long-term contract scenario causes costs to less than double (55% increase). The difference between the "Low" and "Medium" new generation scenario in NP15 is that the latter assumes that all generation projects that are classified as "pending but not approved" before the California Energy Commission are constructed while the latter assumes none of the "pending but not approved" projects are constructed. If one assumes that only half of the generation projects that are "pending but not approved" are actually approved and constructed (i.e. a hybrid scenario between the low and average new generation scenario), the results in Table 5 suggest that the annual cost benefits to NP15 load from upgrading Path 15 would likely exceed $300-400 million even if all of the State's long-tem energy contracts are assumed to remain in place.

Moreover, it is important to keep in mind that the results shown in Tables 3-5 represent estimated annual cost benefits to NP15 load for year 2005 only. While estimating benefits in additional years was beyond the scope of this project and it would be inappropriate to extend the benefits shown in Table 5 to additional years since they are based on among other things, a 1-10 dry hydro season, it may be reasonable to assume a three-year scenario where the second and third year are assumed to be a normal hydro year[17]. Table 6 shows the estimated cost benefits to NP15 Load under a three-year scenario. These results indicate that under a reasonable worst-case three-year scenario, one dry hydro year and two normal hydro years, the total cost benefits to NP15 load over three years may range from $418 to $2,016 million.

Table 6: Cost Benefits under Two Year Scenario (Dry and Normal Hydro Years)

	State's Long-term Contract Assumptions					
	All Contracts Remain in effect in 2005 ($MM)			No Contracts Remain in effect in 2005 ($MM)		
New Generation Scenario	Dry Year (A)	Normal Year (B)	Total 3-Years (A+2*B)	Dry Year (A)	Normal Year (B)	Total 3-Years (A+2*B)
Medium	$208	$105	$418	$321	$173	$667
Low	$850	$212	$1,274	$1,332	$342	$2,016

[17] It would not be advisable to apply the estimated cost benefit for 2005 beyond 3-years as supply and demand conditions in 2008 are apt to be significantly different than in 2005.

Summary and Conclusion

This analysis supplements a larger study completed by the ISO that evaluates the cost and benefits of building additional transmission capacity on Path 15 in year 2005. The main study looks at two potential benefits from upgrading Path 15: 1) net-cost savings to load and 2) reduction in re-dispatch costs. While the ISO's main study provides some important information on the potential economic benefits from upgrading Path 15, its findings are based on the premise of a perfectly competitive electricity market where prices reflect marginal cost and no single supplier has the ability to manipulate prices.

In this report we question this fundamental premise by examining the extent to which suppliers may be able to exercise market power in northern California (NP15) in year 2005 under various scenarios of new generation investments and hydro conditions. To provide for some comparability of results, we utilize the same 24 supply scenarios used in the ISO's main study. We then examine the extent to which market power is mitigated through upgrading Path 15. By providing addition import capability into northern California, the expansion of Path 15 mitigates the ability of suppliers to exercise market power. The results of this analysis indicate there is a potentially significant additional economic benefit from upgrading Path 15 in terms of mitigating costs associated with market power in northern California.

The projected cost of expanding Path 15's transmission capacity is estimated to be approximately $300 million. This is the cost reported in PG&E's conditional application to the CPUC for a Certificate of Public Convenience and Necessity (CPCN) authorizing the construction of the Path 15 expansion. This cost estimate is based on a "full" path 15 reinforcement that includes looping a 500 kv line and having series compensation on the line. A second option exists to not add series compensation initially and to not loop the line in. The cost of this option is estimated to be at $220 million. The results of this analysis, particularly those presented in Tables 5-6, suggest that the potential cost benefits to load in NP15 from expanding Path 15 will likely equal or exceed this cost in one to three years.