

# San Joaquin Local Agency Formation Commission

Market Expert Report

February 23, 2011



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# 1 Introduction and Summary

PA Consulting Group, Inc. (PA) was retained by the San Joaquin Local Agency Formation Commission (SJ LAFCo) to provide support in evaluating the September 14, 2010 Supplement to the Application (Supplement) filed by the South San Joaquin Irrigation District (SSJID) to acquire Pacific Gas and Electric's (PG&E) distribution assets (the "Assets") in Manteca, Ripon, Escalon, and surrounding areas perhaps through eminent domain. Specifically, SJ LAFCo retained PA to review and evaluate the three new business plan analyses that SSJID presented in its Supplement, including:

- *Reinvestment of revenue*
- *Impact of PA's projected power prices on PG&E rates*
- *Investment of additional equity.*

In addition, PA reviewed and analyzed SSJID's projection of SSJID's share in Tri-Dam Project net revenue presented in its Supplement, and derived its own determination of SSJID's share in projected Tri-Dam Project net revenue based on PA's projected power prices.

## 1.1 Overview of this Report

This report provides PA's evaluation of each of the analyses stated above. The report is organized into three main sections including: a section discussing the evaluation of SSJID's Supplement business plan analyses utilizing assumptions from PA's May 21, 2010 Market Expert Report (the "May 2010 Report"); a section discussing the evaluation of SSJID's Supplement business plan analyses utilizing updated market assumptions (the "Updated Market View"); and a section discussing PA's evaluation of SSJID's share in projected Tri-Dam Project net revenue.

Specifically, this Section of the report provides an overview of PA's conclusions; Section 2 provides PA's evaluation of SSJID's Supplement business plan analyses using assumptions from PA's May 2010 Report; Section 3 provides PA's evaluation of SSJID's Supplement business plan analyses using Updated Market View assumptions; Section 4 provides PA's evaluation of SSJID's share in the projected Tri-Dam Project net revenue; Appendix A provides an overview of detailed assumptions utilized in PA's Updated Market View business plan analysis; Appendix B provides an overview of PA's fundamental market assumptions; Appendix C provides an overview of PA's modeling methodology; and Appendix D provides a list of sources relied upon.

## 1.2 Purpose and Intended Use of this Report

The purpose of this report is to present PA's review and evaluation of the three new business plan analyses presented in SSJID's Supplement, as well as PA's determination of SSJID's share in projected Tri-Dam Project net revenue. SJ LAFCo may use this report for assessing the Supplement filed by SSJID. This report may not be used for any other purpose without the written consent of PA.

## 1.3 Evaluation of SSJID Supplement Business Plan Analyses Based on May 2010 Report Assumptions

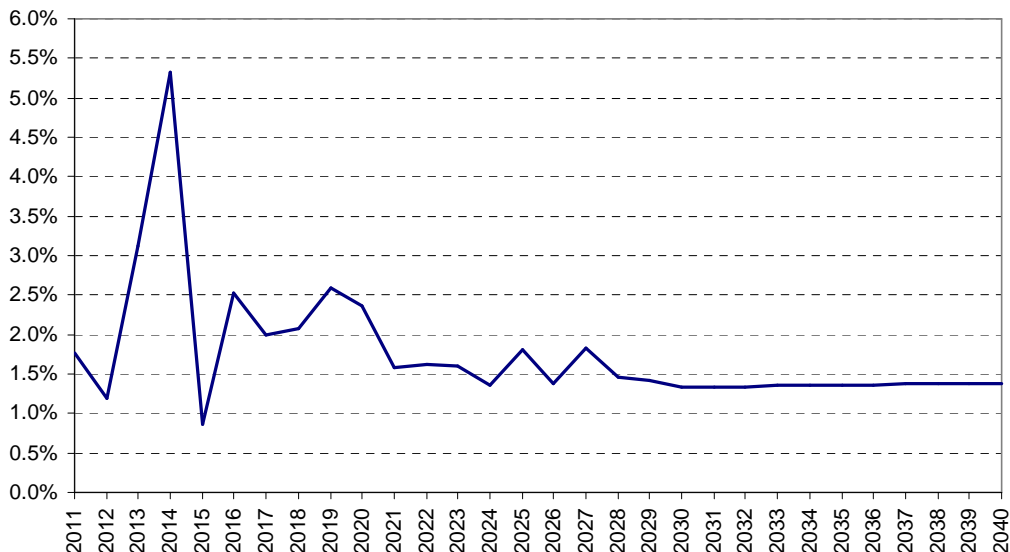
PA reviewed and evaluated the three new business plan analyses presented in SSJID's Supplement. The following paragraphs summarize PA's analysis and conclusions from its evaluation of the three new business plan analyses when utilizing assumptions from PA's May 2010 Report. This includes the use of PA power prices as of December 31, 2009 and PG&E rates as of March 1, 2010.

### 1.3.1 Rate impact of PA power price projections

In its May 2010 Report, PA modeled PG&E's rates increasing with inflation to maintain consistency with SSJID's original business plan. In SSJID's Supplement, SSJID submitted an analysis of its assessment of the impact that PA's forecasted power costs would have on PG&E's rates. PA reviewed SSJID's analysis and also prepared its own estimate of the impact of PA's power price projections on PG&E's rates. It is important to note that PA's analysis only focuses on selected changes to power supply costs and is not intended to reflect a full study and forecast of PG&E's rates, but rather to serve as a proxy to reflect the impact of PA's projected power price projections on PG&E's rates.

In its Supplement, SSJID found that PG&E would require an increase of approximately 11% to its retail rates in 2014, based on its assessment of the impact of PA's projected power costs. PA prepared a more detailed estimate that considered the projected impact on a year-by-year basis. PA's analysis indicates year-by-year increases ranging from 0.9% to 5.3%, with a simple average rate increase of 1.8% over the study period, as shown in Figure 1 below.

**Figure 1: Projected Rate Impact of PA's Power Price Projections**



### 1.3.2 Assessment of SSJID Supplement business plan analyses

SSJID submitted three new business plan analyses as part of its Supplement, concluding through three steps that it could provide retail electric service at a flat rate discount of 15% to PG&E rates. The analysis

was conducted in steps, with each step adding an additional assumption(s) to the business plan model utilized in the previous step.

In its first step, SSJID revised the business plan model<sup>1</sup> evaluated in PA's May 2010 Report by adding a general operating fund and a rate stabilization fund, by funding the first four years of repairs and replacements through operating cash flow, and by commencing principal repayment in year three of the analysis. In its second step, SSJID adjusted the model it utilized in step one of its business plan analysis by making adjustments to its forecast of PG&E rates based on its assessment of impacts of PA's power cost projections. In its third step, SSJID adjusted the model utilized in step two of its business plan analysis by adding additional equity contributions during the term of the business plan.

PA reviewed SSJID's revised business plan models and developed its own models incorporating the new assumptions, to evaluate SSJID's determination that a 15% flat rate discount to PG&E rates could be achieved. In its analysis, PA derived two conclusions regarding the rate discount that SSJID could achieve based on the new business plan analyses. The two conclusions include a flat rate discount and a simple average rate discount to PG&E rates. The flat rate discount reflects the rate discount to PG&E rates that SSJID could hold constant in all years of the business plan, while ensuring sufficient revenue is generated to meet annual debt service coverage ratio (DSCR) and general fund days cash on hand requirements in all years, including the most constrained year during the term of the business plan. The simple average rate discount assumes that SSJID's rate discount to PG&E rates is allowed to vary from year-to-year, increasing or decreasing the rate discount from year-to-year to ensure sufficient revenue is generated to meet annual DSCR and general fund days cash on hand requirements within any single year; with the simple average rate discount conclusion reflecting a simple average of the varying annual rate discounts over the term of the business plan.<sup>2</sup> For purposes of evaluating SSJID's Supplement, PA believes that the simple average rate discount is the more applicable conclusion to rely upon, as it is most similar to the analysis conducted by SSJID.

While SSJID determined that it can provide a 15% flat rate discount to PG&E rates by reinvesting excess operating revenue, by adjusting PG&E rates, and by contributing \$39 million of equity up-front and \$1.6 million on average per year from 2011 to 2027; based on its May 2010 Report assumptions, PA determined that SSJID would need to reinvest excess operating revenue, adjust PG&E rates, and contribute \$39 million of equity up-front and \$5.2 million on average per year over the term of the business plan in order to achieve a flat 15% rate discount to PG&E rates.<sup>3</sup> It should be noted that PA has only evaluated the impact that additional equity contributions would have on potential rate discounts, and not on the source of, or SSJID's ability to provide, such equity contributions.

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<sup>1</sup> Reflects the business plan model presented by SSJID in its Application submitted to SJ LAFCo in September 2009, adjusted for PA's forecast of power costs from its May 2010 Report, PA's determination of value for the Assets from its May 2010 Report, and PG&E's March 1, 2010 rates.

<sup>2</sup> Assumes a maximum rate discount of 15% and rate discounts applied in increments of .5% (i.e., .5%, 1%, 1.5%, etc...).

<sup>3</sup> Reflects a simple average of annual equity contributions.

## 1.4 Evaluation of SSJID Supplement Business Plan Analyses Based on Updated Market View Assumptions

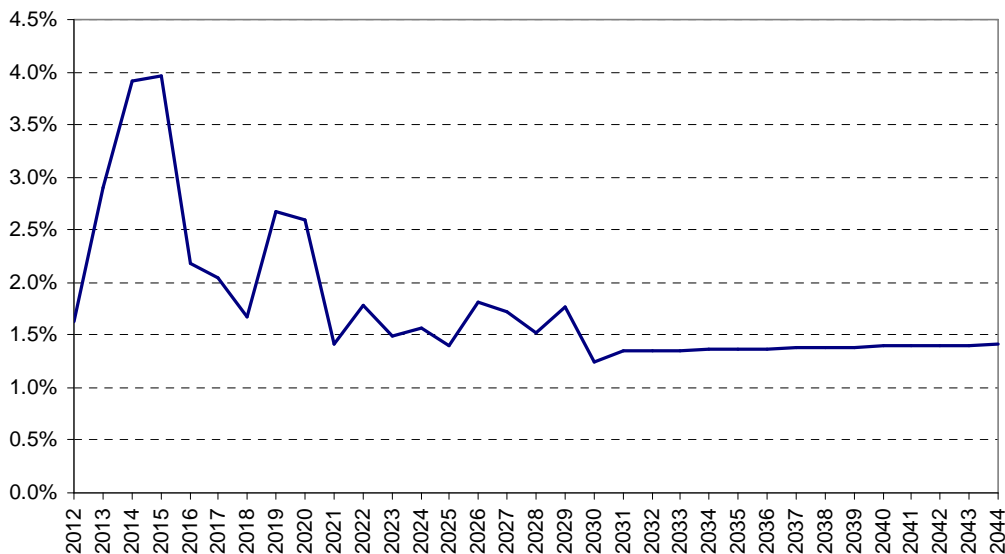
PA also reviewed and evaluated the three new business plan analyses presented in SSJID's Supplement based on Updated Market View assumptions. The Updated Market View includes the use of PA's power price forecast as of November 30, 2010, PG&E's rates as of January 1, 2011, and other updated assumptions related to PA's business plan analysis which are discussed in more detail in Section 3.3.

### 1.4.1 Rate Impact of PA updated power price projections

PA analyzed the rate impact of its updated power price projections. As described in Section 1.3.1, it is important to note that this analysis only focuses on selected changes to power supply costs and is not intended to reflect a full study of PG&E's expected rates, but rather to evaluate the impacts of PA's power price projections on PG&E's rates.

PA's analysis indicates year-by-year increases ranging from 1.2% to 4.0%, with a simple average rate increase over the study period of 1.8%, as shown in Figure 2 below.

**Figure 2: Projected Rate Impact of Updated Power Price Projections**



### 1.4.2 Assessment of SSJID Supplement business plan analyses

As discussed previously, SSJID submitted three new business plan analyses as part of its Supplement. PA analyzed the SSJID Supplement business plan analyses utilizing PA's Updated Market View assumptions.

In its analysis, PA reviewed SSJID's revised business plan models, and developed its own models incorporating the new assumptions, to evaluate SSJID's determination that a 15% flat rate discount to PG&E rates could be achieved. While SSJID determined that it can provide a 15% flat rate discount to

PG&E rates by reinvesting excess operating revenue, by adjusting PG&E rates, and by contributing \$39 million of equity up-front and \$1.6 million on average per year from 2011 to 2027 based on May 2010 Report assumptions; based on its Updated Market View assumptions, PA determined that SSJID would need to reinvest excess operating revenue, adjust PG&E rates, and contribute \$39 million of equity up-front and \$15.0 million on average per year over the term of the business plan in order to achieve a flat 15% rate discount to PG&E rates.<sup>4</sup> It should be noted that PA has only evaluated the impact that additional equity contributions would have on potential rate discounts, and not on the source of, or SSJID's ability to provide, such equity contributions.

## 1.5 Evaluation of Projected Tri-Dam Project Net Revenue

PA reviewed and determined the amount of SSJID's share in Tri-Dam Project net revenue based on its May 2010 Report assumptions and its Updated Market View assumptions. The following paragraphs summarize PA's conclusions on SSJID's share in projected Tri-Dam Project net revenue based on PA's projected power prices.

### 1.5.1 Impact of PA power price projections on Tri-Dam Project net revenue based on May 2010 Report assumptions

As part of its Supplement, SSJID provided a forecast of its assessment of SSJID's share in Tri-Dam Project net revenue based on PA's power cost projections. SSJID determined that SSJID's share in the Tri-Dam Project could generate an average of approximately \$18 million of net revenue per year, over the time period of 2011 to 2020.

PA reviewed SSJID's net revenue forecast for the Tri-Dam Project and created its own net revenue forecast utilizing a combination of data provided by SSJID, public data sources, and PA's market price forecast. PA concludes that SSJID's share in the Tri-Dam Project could generate an average of \$20.1 million of net revenue per year, over the time period of 2011 to 2020, as shown in Table 1 below.

**Table 1: PA Projection of Tri-Dam Project Net Revenue (\$MM)**

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Ten-Year Average <sup>1</sup>	SSJID Share (50%)
\$17.2	\$24.9	\$34.4	\$42.3	\$43.6	\$45.3	\$46.4	\$48.0	\$49.3	\$49.9	\$40.1	\$20.1

<sup>1</sup> Reflects a simple average of the 2011 to 2020 annual net revenue projection.

### 1.5.2 Impact of PA power price projections on Tri-Dam Project net revenue based on Updated Market View assumptions

PA also performed its analysis of forecasted Tri-Dam Project net revenue utilizing its Updated Market View assumptions. PA updated its net revenue model as developed for its analysis discussed in Section 1.5.1 by updating its forecast of power prices, Renewable Energy Credit (REC) prices and ancillary services prices. These pricing updates reflect PA's price projections as of November 30, 2010. Based on its Updated Market View assumptions, PA concludes that SSJID's share in the Tri-Dam Project could

<sup>4</sup> Reflects a simple average of annual equity contributions.

produce an average of \$18.3 million of net revenue per year, over the time period of 2011 to 2020, as shown in Table 2 below.

**Table 2: PA Projection of Tri-Dam Project Net Revenue (\$MM)**

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Ten-Year Average <sup>1</sup>	SSJID Share (50%)
\$12.0	\$22.2	\$30.7	\$32.6	\$41.7	\$42.9	\$44.2	\$45.1	\$46.9	\$48.2	\$36.6	\$18.3

<sup>1</sup> Reflects a simple average of the 2011 to 2020 annual net revenue projection.

## 2 Evaluation of SSJID Supplement Business Plan Analyses using May 2010 Report Assumptions

PA reviewed the Supplement submitted by SSJID in relation to its application to provide retail electric service and its intended purchase of the Assets perhaps through eminent domain. Specifically, SJ LAFCo asked PA to analyze SSJID's contention that it can provide retail electric service at a 15% flat rate discount to PG&E rates, as shown through the three step analysis presented by SSJID in its Supplement, including:

- *Reinvestment of revenue*
- *Impact of PA's projected power prices on PG&E rates*
- *Investment of additional equity.*

In this Section of the report, PA has conducted its analysis using the market assumptions and expectations utilized in its May 2010 Report. Primary assumptions from PA's May 2010 Report include the use of PA power price projections as of December 31, 2009 and PG&E rates as of March 1, 2010. In this Section, PA first discusses its analysis of the impact of PA power price projections on PG&E rates, which is then utilized in the second part of this Section which discusses PA's review and evaluation of the three new business plan analyses presented in SSJID's Supplement.

### 2.1 Rate Impact of PA Power Price Projections

In its May 2010 Report, PA modeled PG&E's rates increasing with inflation to maintain consistency with SSJID's original business plan. In SSJID's Supplement, SSJID submitted an analysis of its assessment of the impact that PA's forecasted power costs would have on PG&E's rates. PA reviewed SSJID's analysis and prepared its own analysis of the rate impact of PA's power price projections. It is important to note that PA's analysis only focuses on selected changes to power supply costs and is not intended to reflect a full rate study for PG&E, but rather to serve as a proxy to reflect the impact of PA's projected power price projections on PG&E's rates.

In its Supplement, SSJID found that PG&E would require an increase of approximately 11% to its retail rates in 2014. SSJID developed this estimate using PA's projection of power costs from its May 2010 Report, as well as publicly available information.

As described below, PA estimated the impact of PA's power price projections on PG&E rates for each year in its study period, 2011 to 2040.

#### 2.1.1 PA's rate impact analysis

To estimate the impact on PG&E's March 1, 2010 rates, PA developed a projection of the change in PG&E's power supply costs as compared to the estimated level included in PG&E's revenue requirements in rates. Based on publicly available information, PA developed an annual projected load and resource

energy balance for PG&E, adjusting for known or projected changes in the following items: fuel costs, Department of Water Resources (DWR) purchases, Qualifying Facility (QF) purchases, renewable purchases and market purchases. PA calculated the projected annual change in costs for each of these items, assuming that other costs increased with inflation. PA then calculated the change in average revenue requirements for each year from 2011 to 2040.

PA's projection included consideration of the following power supply costs not expected to increase with inflation:

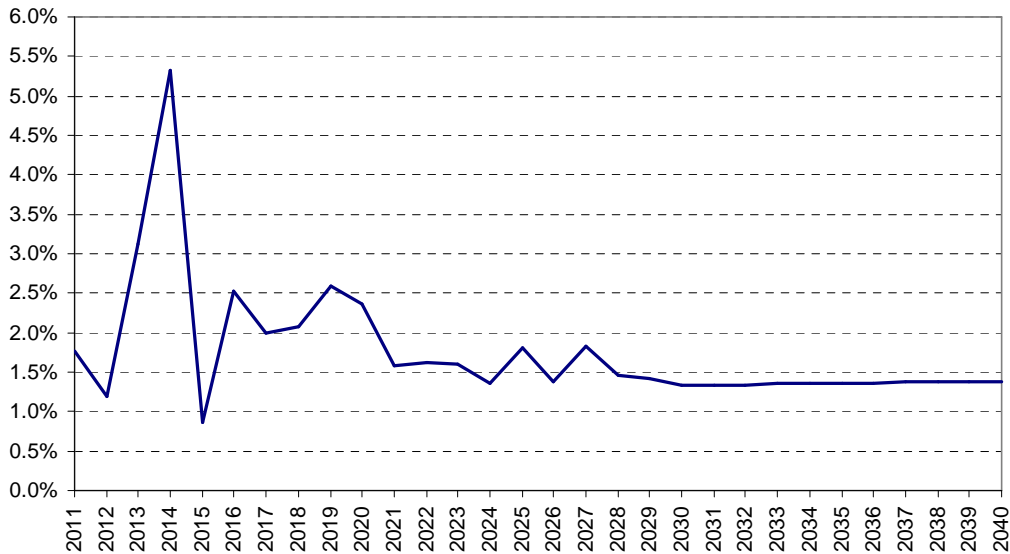
- *Fuel costs:* PA adjusted the fuel costs to reflect projected increases in generation from PG&E's Gateway combined cycle generating unit and the new Colusa unit that was installed in 2010.
- *DWR purchases:* PG&E's obligations for DWR contracts are projected to decrease from over 13,000 gigawatt hours (GWh) in 2009 to zero by 2015. PA included the projected roll-off of these above market-priced contracts.
- *QF purchases:* As of December 31, 2009, PG&E had approximately 240 agreements with QFs for approximately 3,900 megawatts (MW). Approximately 3,300 MW of these agreements will expire by 2028, with 300 MW with no specific expiration dates. PA assumed that these contracts roll off by 2028.
- *Renewable purchases:* PA calculated PG&E's total renewable generation required to meet California's 33% renewable generation target by 2020. PA then determined the additional amount of renewable purchases required to meet the target and priced these at PA's projected price for RECs.
- *Wholesale purchases:* Based on the projected energy requirements for PG&E's bundled customers, PA estimated the additional wholesale purchases for PG&E considering the changes in generation from PG&E's owned combined cycles, DWR purchases, QF purchases and renewable purchases. PA priced these purchases at the average projected power price for PG&E.

PA projected PG&E's total annual revenue requirements by incorporating the projected change in costs for each of the five cost items listed above and assumed that all other revenue requirement items increased with inflation.<sup>5</sup> PA divided the projected annual revenue requirements by the projected level of bundled retail customer sales to determine the average annual revenue requirement. PA then calculated the year-by-year projected change for average annual revenue requirements as presented in Figure 3 below. The year-by-year increases range from 0.9% to 5.3%, with a simple average over the study period of 1.8%.

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<sup>5</sup> As noted previously, this analysis is not a full rate projection for PG&E.

**Figure 3: Projected Rate Impact of Power Price Projections**



The large projected increase in 2014 is primarily driven by the assumption that the wholesale power market will need new capacity at that time, and market prices are expected to increase at that time to reflect the cost of new capacity. The projected increases in several of the other years are driven by projected changes in natural gas prices, which have a significant impact on power prices in the California market, as well as increases due to meeting the renewable energy target.

## 2.2 Impact of Reinvestment of Excess Operating Revenue on SSJID's Business Plan

SSJID submitted a revised business plan analysis as part of its Supplement, and concluded through three steps that it could provide retail electric service at a 15% flat rate discount to PG&E rates. Each step added an additional assumption(s) to the business plan model utilized in the previous step.

In its first step, SSJID revised the business plan model<sup>6</sup> presented in PA's May 2010 Report by adding a general operating fund and a rate stabilization fund, by funding the first four years of repairs and replacements through operating cash flow,<sup>7</sup> and by commencing principal repayment in year three of the analysis;<sup>8</sup> collectively, the reinvestment of excess operating revenue assumptions.

Under SSJID's reinvestment of excess operating revenue analysis, SSJID determined that it could provide retail electric service at a simple average rate discount of 4.3% to PG&E rates, over the time period of 2011 to 2027.

<sup>6</sup> Reflects the business plan model presented by SSJID in its Application submitted to SJ LAFCo in September 2009, adjusted for PA's forecast of power costs from its May 2010 Report, PA's determination of value for the Assets from its May 2010 Report, and PG&E's March 2010 rates.

<sup>7</sup> Assumed to be funded through debt in the May 2010 Report model.

<sup>8</sup> Assumed to commence in year five of the analysis in the May 2010 Report model.

## 2.2.1 PA's determination of potential rate discounts

PA reviewed SSJID's modeled reinvestment of excess operating revenue analysis, and developed its own model incorporating the reinvestment of excess operating revenue assumptions presented above, to evaluate SSJID's determination that a 4.3% simple average rate discount to PG&E rates could be achieved.

In developing its own model, PA began its analysis utilizing the business plan model evaluated in PA's May 2010 Report. PA then adjusted the business plan model by adding a general operating fund and a rate stabilization fund, by funding the first four years of repairs and replacements through operating cash flow, and by commencing principal repayment in year three of the analysis. In addition, while PA excluded interest income in its test of SSJID's business plan in its May 2010 Report, PA has included interest income in its current analysis, as specific cash accounts have been added to the business plan, and PA has assumed those accounts will generate interest income.<sup>9</sup>

In its analysis, PA made the following assumptions:

- Free cash flow is transferred to the general fund, with any free cash flow deficiencies, if any, being funded by cash in the general fund.
- The general fund requires a cash balance equivalent to 120 to 150 days cash on hand.
- Any cash in excess of the 150 days cash on hand requirement in the general fund is transferred to the rate stabilization fund.
- Any contribution to the rate stabilization fund derived from operating cash flow is deducted from net revenue in relation to calculating the DSCR requirement in the year contributed.
- Any distribution from the rate stabilization fund is transferred to operating cash flow and is added to net revenue in relation to calculating the DSCR in the year distributed.
- Annual DSCR requirement of 1.25.

Table 3 below summarizes the results of PA's analysis.

**Table 3: Summary of Rate Discount/(Adder) to PG&E Rates**

	SSJID <sup>1</sup>	PA - Flat <sup>2</sup>	PA - Average <sup>2</sup>
Step 1: Reinvestment of Excess Operating Revenue	4.3%	3.7%	7.1%

<sup>1</sup> SSJID's rate discount reflects the simple average rate discount over 2011 to 2027.

<sup>2</sup> PA's rate discount reflects either a flat rate discount or a simple average rate discount over the term of the business plan. For purposes of evaluating SSJID's Supplement, PA believes that the simple average rate discount is the more applicable conclusion to rely upon, as it is most similar to the analysis conducted by SSJID.

<sup>9</sup> SSJID has utilized an interest income rate of 2% in its business plan model. While PA believes this rate to be potentially high in the near-term, and potentially low in the long-term, it believes it to be a reasonable assumption for purposes of testing the business plan.

## 2.2.2 Differences between PA's and SSJID's analysis

The primary modeling difference between PA's and SSJID's reinvestment of excess operating revenue analysis is the assumption of additions to the rate stabilization fund being deducted from net revenue for purposes of calculating the annual DSCR.<sup>10</sup> PA believes that additions to the rate stabilization fund should be deducted from net revenue for calculating the DSCR in the year contributed. The funds contributed can then be utilized in future years, and are added to net revenue for purposes of meeting DSCR requirements in the year it's distributed from the rate stabilization fund. Using this approach, cash is counted only once towards calculating the DSCR.

## 2.3 Impact of Reinvestment of Excess Operating Revenue and PG&E Rates on SSJID's Business Plan

In step two of SSJID's business plan update, SSJID updated the model it utilized in step one of its business plan analysis by making adjustments to its forecast of PG&E rates, for its assessment of the impacts of PA's power cost projections. Specifically, SSJID increased PG&E rates by 11% in 2014 and by inflation in all other years. Under SSJID's reinvestment of excess operating revenue and PG&E rates analysis, SSJID determined that it could provide retail electric service at a simple average rate discount of 11% to PG&E rates, over the time period of 2011 to 2027.

### 2.3.1 PA's determination of potential rate discounts

PA reviewed SSJID's reinvestment of excess operating revenue and PG&E rates model, and developed its own model incorporating PA's assumptions for the impact of PA's power price projections on PG&E rates, discussed in Section 2.1 above, to evaluate SSJID's determination that an 11% simple average rate discount could be achieved.

In developing its own model, PA began its analysis by utilizing PA's reinvestment of excess operating revenue model as developed for its analysis in Section 2.2, and then adjusted this model to incorporate its assessment of the impacts of PA's power price projections on PG&E rates. Table 4 below summarizes the results of PA's analysis.

**Table 4: Summary of Rate Discount/(Adder) to PG&E Rates**

	SSJID <sup>1</sup>	PA - Flat <sup>2</sup>	PA - Average <sup>2</sup>
Step 2: Reinvestment of Excess Operating Revenue and PG&E Rates	11%	7.1%	9.6%

<sup>1</sup> SSJID's rate discount reflects the simple average rate discount over 2011 to 2027.

<sup>2</sup> PA's rate discount reflects either a flat rate discount or a simple average rate discount over the term of the business plan. For purposes of evaluating SSJID's Supplement, PA believes that the simple average rate discount is the more applicable conclusion to rely upon, as it is most similar to the analysis conducted by SSJID.

<sup>10</sup> Other minor differences exist between PA's and SSJID's analysis; however, these minor differences are not discussed in this report as the differences do not create material differences between rate discount conclusions.

### 2.3.2 Differences between PA's and SSJID's analysis

The primary difference between PA's and SSJID's reinvestment of excess operating revenue and PG&E rates analysis is the assumptions utilized by each for the impacts of PA's power price projections on PG&E rates. While SSJID increased PG&E rates by 11% in 2014 and by inflation in all other years, PA's more detailed analysis utilizes year-by-year increases in PG&E rates based on its analysis presented in Section 2.1. Over the term of the business plan, PA's analysis results in a lower cumulative forecast of PG&E rates.

## 2.4 Impact of Reinvestment of Excess Operating Revenue, PG&E Rates, and Investment of Additional Equity on SSJID's Business Plan

In SSJID's third step of its business plan analysis, SSJID adjusted its business plan model utilized in step two of its business plan analysis by adding additional equity contributions during the term of the business plan. SSJID notes that these equity contributions have been funded from existing cash reserves or from Tri-Dam revenues. SSJID proposes to utilize these additional equity contributions, when necessary, to help maintain rate discounts and the projects financial feasibility. Under SSJID's reinvestment of excess operating revenue, PG&E rates and additional equity analysis, SSJID determined that it can provide retail electric service at a flat rate discount of 15% to PG&E rates, over the term of the business plan.

### 2.4.1 PA's determination of potential rate discounts

PA reviewed SSJID's reinvestment of excess operating revenue, PG&E rates and additional equity model, and developed its own model incorporating PA's assumptions for additional equity contributions. It should be noted that PA has only evaluated the impact that additional equity contributions would have on potential rate discounts, and not on the source of, or SSJID's ability to provide, such equity contributions.

In developing its own model, PA began its analysis by utilizing PA's reinvestment of excess operating revenue and PG&E rates model as developed for its analysis in Section 2.3, and then applied the following assumptions:

- \$39MM of additional equity is contributed to fund the purchase of the Assets, with the remainder financed through debt.<sup>11</sup>
- Annual equity contributions are made throughout the term of the business plan, contributed and utilized for ensuring a minimum 120 days cash on hand balance in the general fund and a 1.25 DSCR.
- Annual equity contributions are made directly to the general fund or rate stabilization fund.

Based on its analysis, PA has determined that SSJID would need to reinvest excess operating revenue, adjust PG&E rates, and contribute \$39 million of equity up-front and \$5.2 million on average per year over the term of the business plan in order to achieve a flat 15% rate discount to PG&E rates.<sup>12</sup> Table 5 below compares the equity contributions assumed in SSJID's and PA's models.

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<sup>11</sup> In SSJID's business plan model submitted in its Application to SJ LAFCo in September 2009, the purchase of the Assets was assumed to be financed entirely through debt.

<sup>12</sup> Reflects a simple average of annual equity contributions.

**Table 5: Equity Required for 15% Flat Rate Discount**

	SSJID	PA
<b>Average Annual Equity Contribution<sup>1,2</sup></b>	\$1.6 million	\$5.2 million
<b>Highest Annual Equity Contribution<sup>3</sup></b>	\$4.8 million	\$9.2 million

<sup>1</sup> For SSJID, reflects a simple average of annual equity contributions over the time period of 2011 to 2027.

<sup>2</sup> For PA, reflects a simple average of annual equity contributions over the term of the business plan.

<sup>3</sup> Reflects the highest required annual equity contribution to meet DSCR and days cash on hand requirements in the model run.

## 2.4.2 Differences between PA's and SSJID's analysis

Due to the modeling differences discussed in Sections 2.2 and 2.3, PA and SSJID differ in the amount and timing of equity contributions. Both analyses are catered towards contributing equity at times when equity is required to ensure a 1.25 DSCR or to ensure minimum days cash on hand requirements are met in the general fund; however, the timing of these equity contributions are inherently different due to the changes to other cash flow items caused by modeling differences outlined in Sections 2.2 and 2.3, which impact the timing and amount of equity required in a given year.

## 2.5 Conclusions

PA reviewed SSJID's revised business plan models and developed its own models incorporating the new assumptions presented in SSJID's Supplement, to evaluate SSJID's determination that a 15% flat rate discount to PG&E rates could be achieved. While SSJID determined that it can provide a 15% flat rate discount to PG&E rates by reinvesting excess operating revenue, by adjusting PG&E rates, and by contributing \$39 million of equity up-front and \$1.6 million on average per year from 2011 to 2027; based on its May 2010 Report assumptions, PA determined that SSJID would need to reinvest excess operating revenue, adjust PG&E rates, and contribute \$39 million of equity up-front and \$5.2 million on average per year over the term of the business plan in order to achieve a flat 15% rate discount to PG&E rates.<sup>13 14</sup>

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<sup>13</sup> Reflects a simple average of annual equity contributions.

<sup>14</sup> Based on PA's analysis, PA determined that if SSJID contributed an average of \$1.6 million of equity annually instead of \$5.2 million of equity annually over the term of the business plan, it could achieve a flat 12.8% rate discount to PG&E rates.

# 3 Evaluation of SSJID Supplement Business Plan Analyses using Updated Market View Assumptions

PA also conducted its analysis discussed in Section 2 utilizing PA's Updated Market View assumptions. Updated Market View assumptions include PA's view of projected power prices as of November 30, 2010 and PG&E rates as of January 1, 2011. As well, other assumptions have been updated in relation to PA's business plan analysis for the Updated Market View scenario, and are discussed in greater detail in Section 3.3.<sup>15</sup>

In this Section of the report, PA has conducted its analysis using the market assumptions and expectations based on its Updated Market View. PA first discusses the Updated Market View and the key drivers of change from its May 2010 Report, second discusses its analysis of the impact of PA's updated power price projections on PG&E rates, which is then utilized in the third part of this Section which discusses PA's review and evaluation of the three new business plan analyses presented in SSJID's Supplement.

## 3.1 Updated Market View

As discussed in PA's May 2010 Report, PA has extensive experience forecasting power prices. PA's price forecasting methodology is described in more detail in Appendix C. Table 6 below provides a comparison of PA's updated cost of power projections to those utilized in its May 2010 Report. PA presents four forecasts. The first two assume that power is procured from the wholesale market, and the second two assume that SSJID enters into a long-term full requirements contract and pays full compensation for a greenfield, or new unit, to recover its going forward costs.

- Case 1: SSJID purchases peak demand and energy requirements from the market and has no renewable procurement until 2020, when it is projected to have 33%.
- Case 2: SSJID purchases peak demand and energy requirements from the market and procures 20% from renewable resources through 2020, and then 33% beginning in 2020.
- Case 3: SSJID enters into a long-term full requirements contract and pays full compensation for a greenfield, or new unit, to recover its going forward costs and has no renewable procurement until 2020, when it is projected to have 33%.
- Case 4: SSJID enters into a long-term full requirements contract and pays full compensation for a greenfield, or new unit, to recover its going forward costs and procures 20% from renewable resources through 2020, and then 33% beginning in 2020.

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<sup>15</sup> Provided the uncertainty around the timing of a potential valuation trial as part of the eminent domain proceedings, PA has not updated its valuation of the Assets as part of this analysis. The valuation PA has utilized is consistent with its May 2010 Report, and is as of December 31, 2010.

PA notes that SSJID, as a municipal entity, would not be required under the current standards in California to procure renewable power until 2020. However, SSJID has stated its intention to procure renewable power prior to the requirement. As such, Case 2 is most similar to the case presented by SSJID in its September 2009 Application to SJ LAFCo, in terms of assumptions regarding renewable procurement.

SSJID would have multiple choices in procuring power that could result in the range of cases 1 through 4, particularly in the short-term. However, for its Updated Market View, these cases largely converge beginning in 2015, with the only difference being the assumption of renewable procurement. This is due to the fact that the market will need new capacity beginning in 2015, and therefore market prices will need to increase to reflect greenfield, or new capacity.

**Table 6: Cost of Power Comparison (\$/MWh)**

Year	May 2010 Report				Updated Market View			
	Case 1	Case 2	Case 3	Case 4	Case 1	Case 2	Case 3	Case 4
2013	75.10	83.32	96.47	104.69	65.50	74.92	86.12	95.54
2014	100.19	106.88	100.19	106.88	69.86	78.79	91.23	100.16
2015	103.62	110.14	103.62	110.14	96.93	104.26	96.93	104.26
2016	108.13	114.28	108.13	114.28	99.75	107.00	99.75	107.00
2017	110.86	116.87	110.86	116.88	103.12	110.22	103.12	110.22
2018	114.96	120.71	114.96	120.71	105.15	112.37	105.15	112.37
2019	118.40	123.81	118.41	123.81	109.35	116.31	109.35	116.31
2020	129.10	129.10	129.10	129.10	123.83	123.83	123.83	123.83
2021	132.31	132.31	132.31	132.31	125.47	125.47	125.47	125.47
2022	135.76	135.76	135.76	135.76	129.27	129.27	129.27	129.27
2023	138.90	138.90	138.90	138.90	131.64	131.64	131.64	131.64
2024	141.05	141.05	141.05	141.05	134.34	134.34	134.34	134.34
2025	145.03	145.03	145.03	145.03	136.36	136.36	136.36	136.36
2026	147.12	147.12	147.12	147.12	140.00	140.00	140.00	140.00
2027	151.37	151.37	151.37	151.37	143.54	143.54	143.54	143.54

As Case 2 is most similar to the case presented by SSJID in its September 2009 Application in terms of assumptions regarding renewable procurement, PA has utilized Case 2 in its analysis of SSJID's updated business plan. For the remainder of this Section, references to PA's cost of power reflect Case 2 from PA's Updated Market View. In addition, references to PG&E rates reflect PG&E's January 1, 2011 rates.

### 3.1.1 Key drivers

PA's updated forecast of power costs is lower than its May 2010 Report forecast of power costs driven by market recovery timing, natural gas prices, and greenhouse gas legislation/pricing, partially offset by once-through cooling regulation and REC pricing. These drivers are discussed in more detail below.

### ***Market Recovery***

One metric that is often used to describe the balance between supply and demand in a given regional electricity market is the "reserve margin," defined as the extent to which supply of generating capacity exceeds peak electricity demand. A reserve margin of 15% indicates that supply exceeds expected peak demand by 15%. Holding other factors constant, lower reserve margins (less surplus generation) typically lead to higher power prices, since the less efficient (more expensive) capacity in the region is more often needed to satisfy electricity demand. Generally, regions have target reserve margins which are established to maintain reliability. If a region reaches that target, then new capacity must be added in order to maintain the reserve margin and reliability. This is referred to as "equilibrium." As markets migrate toward equilibrium, when new build capacity is required to maintain a target reserve margin, overall market compensation is generally expected to increase to support the cost of these additions. PA projects that market equilibrium will occur in California in 2015 under its Updated Market View, which is why there is a significant increase in prices in Cases 1 and 2 from 2013 to 2015. Cases 3 and 4 do not exhibit this increase, as the price of new generation is already assumed beginning in 2013.

PA projects that market equilibrium will occur in California in 2015 under its Updated Market View, which is extended one year later from its May 2010 Report, primarily due to the addition of close to 2 GW of firm supply in the updated analysis as compared to the May 2010 Report.

### ***Natural Gas Prices***

Natural gas prices are a significant driver to power prices in California. The price of electricity in any given hour is typically related to the operating costs of the marginal, or price-setting, generator. Assuming economic behavior by market participants, generating units are generally dispatched in order of their variable costs (units with lower costs are dispatched first and high-cost units are dispatched as load grows), so the variable costs of the last (or marginal) unit needed to satisfy demand typically drives the regional power price. In California, power generators that burn natural gas are on the margin over 90% of the hours. Therefore, natural gas prices are a key driver to power prices in California. Appendix B provides additional information on the natural gas price forecast utilized by PA in its Updated Market View.

Delivered natural gas prices for Northern California are based on PA's market-by-market view of regional and local transportation, demand seasonality and spot basis differentials to the Henry Hub. Henry Hub projections incorporate NYMEX futures as of November 30, 2010, for 2011 and 2012. For 2013 and 2014, natural gas prices are trended toward a consensus forecast commencing in 2015, derived from projections published by the Energy Information Administration (EIA), Global Insight, and Strategic Energy & Economic Research, Inc. (SEER).

PA's forecast for natural gas prices has decreased since its May 2010 Report. The primary driver of this decline is lower forward pricing and lower forecasted gas pricing from consensus forecasters. Delivered natural gas prices for Northern California have decreased approximately 15% from PA's May 2010 Report to its Updated Market View.<sup>16</sup> In general, lower natural gas prices will result in lower power prices in California.

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<sup>16</sup> Calculated as the percentage difference in delivered gas prices, on a real dollar basis, from 2013 to 2027.

## ***Greenhouse Gas Legislation/Pricing***

Several efforts are currently underway to limit emissions of greenhouse gases (GHG), each varying in approach and reach. Federal GHG programs have been proposed in Congress, one of which has been passed by the House of Representatives, although none have successfully been signed into law. The EPA has been moving forward to regulate GHGs under two separate Clean Air Act (CAA) programs, and members of Congress have subsequently attempted to take action to stop them. At the state level, a regional cap-and-trade program has been implemented in the Northeast, and others have been proposed in the West and Midwest.

While the possibility of legislation in Congress has dimmed, the EPA is moving forward with its own GHG emissions regulation under the CAA in a two-pronged approach. Under the so-called "Tailoring Rule", facilities would need to meet Best Available Control Technology (BACT) standards for emissions reductions. While BACT standards would be determined on a case-by-case basis, the EPA has issued technical guidance which outlines a number of relatively simple technological improvements and efficiency gains that may qualify to meet the BACT standard. At this juncture, it is still unclear the impact these regulations will have on existing power producers, although initial indications are that BACT standards could be met with minimal widespread disruption. Regulations for some sources went into effect at the beginning of 2011, with more sources to be covered in June 2011.

In another CAA effort, the EPA is required to set performance standards for new and modified electric generating units (EGUs) and emissions guidelines for existing EGUs under the New Source Performance Standard (NSPS) program. The EPA will propose the GHG standards by July 26, 2011, with final rules to be promulgated by May 26, 2012, although compliance would not likely be required until 2015 or 2016. The NSPS standards will set GHG emissions limits for EGUs, although the EPA has not yet indicated how strict the limits will be.

The EPA's authority to regulate greenhouse gases under the CAA is currently being litigated by several parties and Congressional action could also delay or limit the EPA's ability to enforce these regulations. In the previous session of Congress, Senator Rockefeller introduced a bill to delay EPA regulation by two years, while Senator Murkowski introduced a bill which would have overridden EPA's authority to regulate GHGs. Several more bills to limit or defund the EPA's GHG authority have already been introduced in the current session of Congress.

Unsatisfied with federal efforts to regulate GHGs, some states have moved forward with their own programs, including California. The Western Climate Initiative (WCI) is a program to regulate greenhouse gas emissions from six Western U.S. states and four Canadian provinces under a cap-and-trade program set to begin in 2012. California has taken steps independently, passing the Global Warming Solutions Act (GWSA) in 2006, which calls for a return of California's emissions to 1990 levels by 2020.<sup>17</sup> California

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<sup>17</sup> In addition to the GWSA, Senate Bill (SB) 1368 prohibits California utilities from investing in or entering into new long-term power purchase agreements unless the contracted baseload generation emits carbon dioxide at a level equal to or below that of a new natural gas-fired combined cycle facility. This standard applies to generation originating within the California market and, more significantly, power imports into the state. The rule effectively prevents coal-fired generation from being imported into the state on a long-term, contracted basis, but does not restrict purchases on a short-term basis. Already, Southern California Edison is seeking California Public Utility Commission approval to sell its 720 MW interest in the Four Corners plant by 2012 because investments in environmental controls would be required to continue operations, and LADWP is considering selling its 477 MW interest in the Navajo plant (due to expire in 2019).

plans to harmonize its GWSA cap-and-trade program with the WCI program, although only a handful of WCI entities (e.g., California and the Canadian provinces) will be ready to participate in the program starting in 2012.

In the wake of the economic downturn, support for these state and regional programs has been flagging. Notably, Arizona withdrew from the WCI in February 2010, and a bill has been introduced in the Washington state Senate that would order a withdrawal from the WCI. In a dramatic sequence of events, the newly-elected New Mexico Governor suspended publication of the rules related to the WCI and fired members of the state Environmental Improvement Board who developed the rules, although the New Mexico Supreme Court recently ordered the rules to be published. In California, Proposition 23 was a citizens referendum which sought to suspend California's development of the GWSA and participation in WCI, but voters rejected the measure in November 2010.

PA's Updated Market View assumes the WCI program begins in 2012, and that a federal GHG program begins in 2018. PA assumes the WCI program will have allowance costs of approximately \$9/short ton in 2012, climbing to approximately \$15/short ton in 2017. PA assumes the federal program will result in a "politically acceptable" allowance cost of \$15/short ton of carbon dioxide (CO<sub>2</sub>) beginning in 2018, climbing to \$30/short ton by 2028, based on analysis of previously proposed GHG legislation and public, industry, and political reaction to the proposals. PA also assumes that regional programs such as WCI will be integrated with the federal program.

PA's current assumption for GHG legislation and pricing differs from its assumptions utilized in its May 2010 Report. Most notably, PA has revised its assumption for the implementation of a federal GHG emissions program from 2013 to 2018, primarily due to changes in the national political landscape leading up to and after the November 2010 midterm elections. PA's assumption for the WCI program commencing in 2012 is unchanged from its May 2010 Report. Given PA's assumption of the WCI program beginning in 2012, the impact of this change in federal GHG timing is less significant for California generators.

### ***Once-Through Cooling Water Regulations***

Sections 316(a) and 316(b) of the Federal Water Pollution Control Act (also known as the Clean Water Act) require the EPA to regulate cooling system thermal discharge and intake structures at industrial facilities in the United States, including power plants. In 1993, a group of environmental groups alleged that the EPA had not performed its duty to implement regulations under Section 316(b), and in November 2010, a settlement was reached which sets the stage for EPA regulation of intake structures. By March 14, 2011, the EPA is required to publish draft rules and by July 27, 2012 the EPA is required to finalize rules regulating cooling water intake structures, according to the settlement. The timing of implementation would vary by plant, depending on when discharge permits are up for renewal.

The EPA regulations may require existing plants to replace once-through cooling (OTC) systems with more expensive closed loop systems. Currently, over half of the existing fleet of thermal power plants in the United States are equipped with OTC systems. Besides significant up front capital expenditures, replacing these systems with closed loop systems may result in reduced power output of 2-4% due to incremental parasitic load and losses in thermal efficiency. Net power output losses would be highest when summer ambient conditions are at their hottest and most humid, coinciding with summer peak days in many regions.

On May 4, 2010 the California State Water Board (SWB) adopted a California specific policy on the use of OTC systems. The policy was approved by the Office of Administrative Law (OAL) on September 27, 2010

and came into effect on October 1, 2010. The policy establishes technology-based standards to reduce the harmful effects associated with cooling water intake structures on marine and estuarine life, and will apply to 19 existing power plants (including the state's two nuclear plants, Diablo Canyon and San Onofre) that currently utilize OTC systems for their water needs.

The policy provides, in general, for two compliance options (Track 1 and Track 2). Track 1 requires a 93% reduction in intake flow rate, and through-screen intake velocity must not exceed 0.5 foot per second; in practice, this compliance option requires the installation of a closed cycle wet or dry cooling system to meet the policy standards. A facility may choose Track 2 if it can prove that a closed cycle system is infeasible at the plant; alternative mechanisms can be employed, but results similar to Track 1 must still be achieved.

The state's nuclear facilities, Diablo Canyon and San Onofre, have additional compliance options. As of the date of this analysis, PA's analysis assumed that an amendment to the OTC rule would be adopted by the SWB, which would also give California's natural gas-fired combined cycle facilities additional compliance options.<sup>18</sup> If the nuclear plants are unable to effectively meet the minimum compliance requirements, owners will work with the SWB to determine the best path forward. Additionally, under the proposed amendment, combined cycle facilities may continue using once-through cooling systems, if the owners of such facilities issue a notice declaring a date that coincides with the end of useful life of the facility (and the facility is retired on this date).

Based on these compliance options, PA's updated analysis assumes that the steam gas units regulated under the rule are retired, and on the timeline outlined in the regulations. Due to these regulations being introduced when PA was finalizing its May 2010 Report, PA did not model these state-specific rules in its May 2010 analysis.

### ***Renewable Energy Credits***

A REC represents one megawatt hour of electricity generated from a renewable power source. To the renewable resource, the value of a REC is an additional revenue stream. To the load-serving entity (LSE) or IOU that is required to procure RECs to meet state Renewable Energy Standards (RES), the value of the REC is a cost of compliance. Market REC prices are fundamentally derived from the additional compensation required by the marginal renewable resource to break-even with its levelized cost, after accounting for energy and capacity revenues and federal tax benefits. The market based REC price will fluctuate based on many drivers, including energy prices, supply and demand of renewable resources, the existence or lack of local, state and federal tax benefits, the type of renewable power asset setting the marginal REC price, and most importantly, the existence and terms of a state RES to create demand, or lack thereof.

Among other factors, the decrease in projected power prices in California, driven by the changes outlined in this Section, particularly lower gas prices, caused projected market REC prices to increase.

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<sup>18</sup> While initially supported by the SWB, this amendment was defeated on December 14, 2010. However, litigation is still pending regarding these regulations.

## 3.2 Rate Impact of PA Power Price Projections

PA prepared an estimate of the impact of its updated power price projections on PG&E's rates. It is important to note that this analysis only focuses on selected changes to power supply costs and is not intended to reflect a full rate study for PG&E, but rather to serve as a proxy to reflect the impact of PA's updated power price projections.

### 3.2.1 PA's rate impact analysis

For its Updated Market View, PA prepared an analysis similar to the one described in Section 2.1. Based on publicly available information, PA developed an annual projected load and resource energy balance for PG&E adjusting for known or projected changes in the following items: fuel costs, DWR purchases, QF purchases, renewable purchases and market purchases. PA calculated the projected annual change in costs for each of these items, assuming that other costs increased with inflation. PA then calculated the change in average revenue requirements for each year from 2012 to 2044.

PA's projection included consideration of the following power supply costs not expected to increase with inflation:

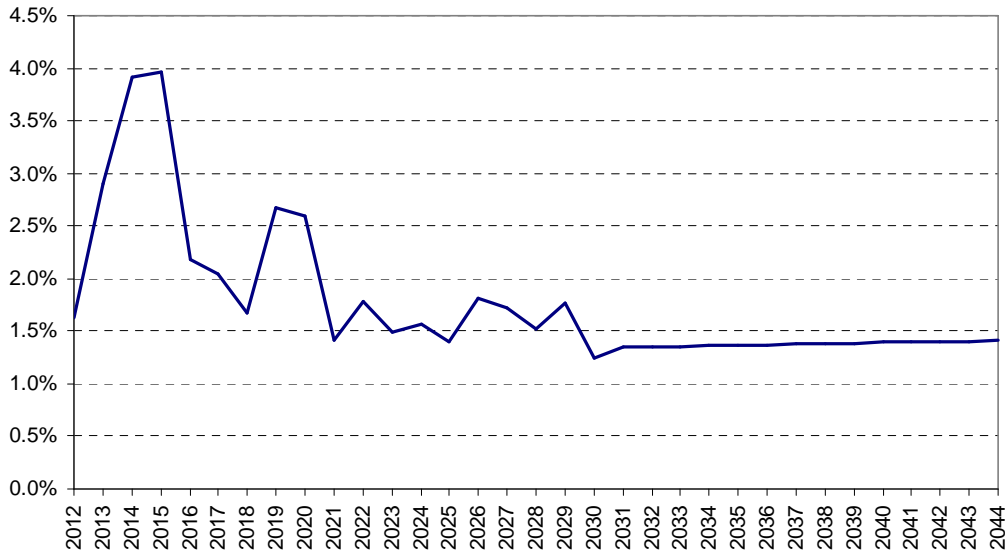
- *Fuel costs:* PA adjusted the fuel costs to reflect projected increases in generation from PG&E's Gateway combined cycle generating unit and the new Colusa unit that was installed in 2010.
- *DWR purchases:* PG&E's obligations for DWR contracts are projected to decrease from over 13,000 GWh in 2009 to zero by 2015. PA included the projected roll-off of these above market priced contracts.
- *QF purchases:* As of December 31, 2009 PG&E had approximately 240 agreements with QFs for approximately 3,900 MW. Approximately 3,300 MW of these agreements will expire by 2028, with 300 MW with no specific expiration dates. PA assumed that these contracts roll off by 2028.
- *Renewable purchases:* PA calculated PG&E's total renewable generation required to meet the 33% renewable generation target by 2020. PA then determined the additional amount of renewable purchases required to meet the target and priced these at PA's projected price for RECs.
- *Wholesale purchases:* Based on the projected energy requirements for PG&E's bundled customers, PA estimated the additional wholesale purchases for PG&E considering the changes in generation from PG&E's owned combined cycles, DWR purchases, QF purchases and renewable purchases. PA priced these purchases at the average projected power price for PG&E.

PA projected PG&E's total annual revenue requirements by incorporating the projected change in costs for each of the five cost items listed above and assumed that all other revenue requirement items increased with inflation.<sup>19</sup> The average annual revenue requirement was calculated by dividing the projected annual revenue requirements by the projected level of bundled retail customer sales. PA then calculated the year-by-year projected increase in average revenue requirements as presented in Figure 4. The year-by-year increases range from 1.2% to 4.0%, with a simple average increase over the study period of 1.8%.

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<sup>19</sup> As noted previously, this analysis is not a full rate projection for PG&E which would require consideration of the year-by-year changes in all items in the total revenue requirements.

**Figure 4: Projected Rate Impact of Updated Power Price Projections**



The large projected increase in 2015 is primarily driven by the assumption that the market will need new capacity at that time, so the market prices increase to reflect the cost of new capacity. The projected increases in several of the other years are driven by projected changes in natural gas prices, which have a significant impact on power prices in the California region, as well as increases due to meeting the renewable energy targets.

### 3.3 Impact of Updated Market View on SSJID's Business Plan

PA updated its analysis of SSJID's three new business plan analyses presented in Section 2 based on its Updated Market View. Other assumptions related to PA's business plan analysis have been updated for its Updated Market View, and include the assumed timing of SSJID's retail electric operational start date, blended rates, projected load profile, and exit fees/non-bypassable payments. Each of these items is discussed in greater detail below and has been incorporated in the business plan models discussed in the remainder of this Section.

#### ***Timing of SSJID's Retail Electric Operational Start Date***

For its May 2010 Report business plan analysis, PA assumed, consistent with SSJID's view at that time, that SSJID's retail electric operational start date would be 2011. For its Updated Market View analysis, PA has updated its assumed SSJID retail electric operational start date assumption based on its updated view of the amount of time necessary to conclude eminent domain proceedings and to prepare the Assets for operational start. In this regard, PA's base case assumption for the timing of SSJID's retail electric operational start date for its Updated Market View analysis is mid-2013. Provided the uncertainty around numerous factors affecting the time necessary to conclude eminent domain proceedings and to prepare the Assets for operational start, PA has provided footnotes in the remainder of this Section to showcase conclusions based on an operational start date of one-year earlier (mid-2012) and one-year later (mid-2014) than its base case assumption.

### ***Blended Rates***

PA has updated its analysis to utilize PG&E's January 1, 2011 rates. In general, PG&E's January 1, 2011 rates are lower than PG&E's March 1, 2010 rates utilized by PA in its May 2010 Report.

In addition to updating to the January 1, 2011 rates, PA has updated its assumption for the rates utilized to represent each respective customer class within SSJID's business plan. Customer classes within SSJID's business plan include Residential, Small Commercial, Large Commercial, Industrial, Agriculture, and Streetlights. In its May 2010 Report, PA assumed the following rates as representative of each customer class, consistent with SSJID:

- Residential - E-1
- Small Commercial - A-1
- Large Commercial - A-10S
- Industrial - E-19S
- Agriculture - AG-4B
- Streetlights

For its Updated Market View analysis, PA analyzed actual 2008 and actual November 2009 to October 2010 sales data for the proposed SSJID service territory, and derived a blended rate for each customer class. As an example, for the Residential customer class, SSJID's service territory could contain a mix of residential customers spanning a number of residential rate classes such as E-1, E-6, E-7, E-8, and so on. Due to this, PA derived a blended rate that accounted for the proportion and rate of each of these unique residential customer types within SSJID's service territory, based on 2008 historical sales information. This same approach was applied for all other customer classes, based on sales information reflective of each customer class within SSJID's service territory. PA believes that this approach derives a more representative rate for the individual customer classes within SSJID's business plan.

### ***Projected Load Profile***

PA analyzed actual 2008 and actual November 2009 to October 2010 sales data for the proposed SSJID service territory, and derived an updated allocation of load for each individual customer class (i.e., Residential, Small Commercial, Large Commercial, Industrial, Agriculture, Streetlights). To do so, PA allocated historical November 2009 to October 2010 sales data into individual customer classes, consistent with the customer classes assumed within the business plan, and calculated the proportion of total sales for each individual customer class to total sales for all classes. PA then applied the derived individual customer class proportions to its existing total load assumption assumed in its May 2010 Report business plan model for 2010.<sup>20</sup> Most notably, this adjustment resulted in a larger proportion of assumed Industrial customers and a lower proportion of assumed Large Commercial customers, as compared to the May 2010 Report business plan model assumptions. PA believes that the updated load allocation for each individual customer class provides a more accurate estimate of customer class loads to be applied against its derived blended customer class rates.

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<sup>20</sup> PA utilized the existing total load assumption within its May 2010 Report business plan model, as the total load assumption was within a reasonable deviation from actuals.

### ***Exit Fees/Non-Bypassable Payments***

PA updated the forecast of exit fees/non-bypassable payments assumed in the business plan model for its Updated Market View analysis. This update reflects updated rates as of January 1, 2011 for the DWR Bond charge, the Power Charge Indifference Adjustment (PCIA), the Nuclear Decommissioning charge, the Energy Cost Recovery Amount (ECRA) charge, and the Competition Transition Charge (CTC). In its analysis, PA assumed that the DWR Bond charge expires in 2022; the Nuclear Decommissioning charge does not expire; the ECRA charge expires in 2012; and the PCIA and CTC charges would adjust to zero, once market benchmark costs exceed portfolio costs associated the charges.

Regarding its assumed PCIA charges, PA assumed that the costs of new generation were not included in the exit fees/non-bypassable payments charged to SSJID or its customers, consistent with SSJID's assumption. It should be noted, however, that non-bypassable charges related to new generation are dependent upon review by the California Public Utility Commission (CPUC) on the fair share of new generation costs for departing load customers. This review analyzes a number of items, including the determination on if the departing load would have been factored into long-term procurement plans for the publicly owned utility. Provided the uncertainty around the conclusions of fair share cost responsibility for SSJID or its customers, PA has not modified SSJID's assumption of cost responsibility associated with new generation resources; but notes that cost responsibility for non-bypassable charges related to new generation costs is possible, dependent upon CPUC review.

## **3.4 Impact of the Updated Market View and Reinvestment of Excess Operating Revenue on SSJID's Business Plan**

As discussed in Section 2, SSJID submitted a revised business plan analysis as part of its Supplement. The analysis presented in SSJID's Supplement was conducted in three steps. Each step added an additional assumption(s) to the business plan model utilized in the previous step.

In step one of its business plan update, SSJID updated its business plan model for the reinvestment of excess operating revenue assumptions. Based on its reinvestment of excess operating revenue analysis, SSJID determined that it could provide retail electric service at a simple average rate discount of 4.3% to PG&E rates, over the time period of 2011 to 2027.

### **3.4.1 PA's determination of potential rate discounts**

PA reviewed SSJID's reinvestment of excess operating revenue model, and developed its own model incorporating the new assumptions for reinvestment of excess operating revenue and its Updated Market View, to evaluate SSJID's determination that a 4.3% simple average rate discount could be achieved. It should be noted that SSJID's rate discount determination does not reflect Updated Market View assumptions.

In developing its own model, PA began its analysis by utilizing PA's reinvestment of excess operating revenue model as developed for its analysis in Section 2.2, which included updates for adding a general operating fund and a rate stabilization fund, for funding the first four years of repairs and replacements

through operating cash flow, and for commencing repayment of principal in year three of the analysis.<sup>21</sup> PA then made additional adjustments to this model for PA's Updated Market View, including updating the cost of power forecast, PG&E rates, timing of SSJID's retail electric operational start date, blended rates, projected load profile and exit fees/non-bypassable payments.

Table 7 below summarizes the results of PA's analysis.<sup>22</sup>

**Table 7: Summary of Rate Discount/(Adder) to PG&E Rates**

	SSJID <sup>1,2</sup>	PA - Flat <sup>3</sup>	PA - Average <sup>3</sup>
Step 1: Reinvestment of Excess Operating Revenue	4.3%	(7.0)%	(1.1)%

<sup>1</sup> SSJID rate discounts have not been updated for updated market assumptions.

<sup>2</sup> SSJID's rate discount reflects the simple average rate discount over 2011 to 2027.

<sup>3</sup> PA's rate discounts reflect either a flat rate discount or a simple average rate discount over the term of the business plan. For purposes of evaluating SSJID's Supplement, PA believes that the simple average rate discount is the more applicable conclusion to rely upon, as it is most similar to the analysis conducted by SSJID.

### 3.5 Impact of Updated Market View, Reinvestment of Excess Operating Revenue and PG&E Rates on SSJID's Business Plan

In step two of SSJID's business plan update, SSJID updated the model it utilized in step one of its business plan analysis by increasing PG&E retail rates for its assessment of the impact of PA's power price projections. Under SSJID's reinvestment of excess operating revenue and PG&E rates analysis, SSJID determined that it could provide retail electric service at a simple average rate discount of 11% to PG&E rates, over the time period of 2011 to 2027.

#### 3.5.1 PA's determination of potential rate discounts

PA reviewed SSJID's reinvestment of excess operating revenue and PG&E rates model, and developed its own model incorporating its assessment of the impact of PA's Updated Market View power price projections on PG&E rates, to evaluate SSJID's determination that an 11% simple average rate discount could be achieved. It should be noted that SSJID's rate discount determination does not reflect Updated Market View assumptions.

In developing its own model, PA began its analysis by utilizing its Updated Market View reinvestment of excess operating revenue model developed for its analysis in Section 3.4. PA then applied the annual impact of PA's updated power price projections on PG&E rates, as presented in Section 3.2, to the PG&E rates assumed in its model.

<sup>21</sup> PA has assumed that the general fund is funded, primarily, through free cash flow over the first year of operations. As such, minimum days cash on hand requirements are tested starting after one full-year of operations.

<sup>22</sup> PA concluded that with an operational start date of mid-2012 or mid-2014, a flat rate discount/(adder) of (5.8)% or (11.7)% and a simple average rate discount/(adder) of (1.0)% or (1.6)% could be achieved, respectively.

Table 8 summarizes the results of PA's analysis.<sup>23</sup>

**Table 8: Summary of Rate Discount/(Adder) to PG&E Rates**

	SSJID <sup>1,2</sup>	PA - Flat <sup>3</sup>	PA - Average <sup>3</sup>
Step 2: Reinvestment of Excess Operating Revenue and PG&E Rates	11%	(1.5)%	3.0%

<sup>1</sup> SSJID rate discounts have not been updated for updated market assumptions.

<sup>2</sup> SSJID's rate discount reflects the simple average rate discount over 2011 to 2027.

<sup>3</sup> PA's rate discounts reflect either a flat rate discount or a simple average rate discount over the term of the business plan. For purposes of evaluating SSJID's Supplement, PA believes that the simple average rate discount is the more applicable conclusion to rely upon, as it is most similar to the analysis conducted by SSJID.

### 3.6 Impact of Updated Market View, Reinvestment of Excess Operating Revenue, PG&E Rates, and Investment of Additional Equity on SSJID's Business Plan

In step three of SSJID's business plan update, SSJID adjusted its business plan model utilized in step two of its business plan analysis by adding additional equity contributions during the term of the business plan. Under SSJID's reinvestment of excess operating revenue, PG&E rates and equity analysis, SSJID determined that it could provide retail electric service at a flat rate discount of 15% to PG&E rates, over the term of the business plan.

#### 3.6.1 PA's determination of potential rate discounts

PA reviewed SSJID's reinvestment of excess operating revenue, PG&E rates, and additional equity model, and developed its own model incorporating PA's assumptions for additional equity contributions, to evaluate SSJID's determination that a 15% flat rate discount could be achieved. It should be noted that PA has only evaluated the impact that additional equity contributions would have on potential rate discounts, and not on the source of, or SSJID's ability to, provide such equity. It should also be noted that SSJID's rate discount determination does not reflect Updated Market View assumptions.

In developing its own model, PA began its analysis by utilizing its Updated Market View reinvestment of excess operating revenue and PG&E rates model as developed for its analysis in Section 3.5. PA then made the following assumptions:

- \$39MM of additional equity is contributed to fund the purchase of the Assets, with the remainder financed through debt.
- Annual equity contributions are made throughout the term of the business plan, contributed and utilized for ensuring a minimum 120 days cash on hand balance in the general fund and a 1.25 DSCR.
- Annual equity contributions are made directly to the general fund or rate stabilization fund.

<sup>23</sup> PA concluded that with an operational start date of mid-2012 or mid-2014, a flat rate discount/(adder) of (0.3)% or (6.8)% and a simple average rate discount of 3.0% or 2.5% could be achieved, respectively.

Based on its Updated Market View assumptions, PA determined that SSJID would need to reinvest excess operating revenue, adjust PG&E rates, and contribute \$39 million of equity up-front and \$15.0 million on average per year over the term of the business plan in order to achieve a flat 15% rate discount to PG&E rates.<sup>24 25</sup> PA also analyzed the amount of equity that would be required to achieve a 5% or 10% flat rate discount to PG&E rates, which is presented in Table 9 below.

**Table 9: Equity Required for 5%, 10%, or 15% Flat Rate Discount**

	5%	10%	15%
<b>Average Annual Equity Contribution<sup>1</sup></b>	\$0.9 million	\$7.0 million	\$15.0 million
<b>Highest Annual Equity Contribution<sup>2</sup></b>	\$4.8 million	\$12.5 million	\$19.2 million

<sup>1</sup> Reflects a simple average of annual equity contributions over the term of the business plan.

<sup>2</sup> Reflects the highest required annual equity contribution to meet DSCR and days cash on hand requirements in the model run.

### 3.7 Conclusions

PA reviewed SSJID's revised business plan models, and developed its own models incorporating the new assumptions, to evaluate SSJID's determination that a 15% flat rate discount to PG&E rates could be achieved. While SSJID determined that it can provide a 15% flat rate discount to PG&E rates by reinvesting excess operating revenue, by adjusting PG&E rates, and by contributing \$39 million of equity up-front and \$1.6 million on average per year from 2011 to 2027, based on May 2010 Report assumptions; based on its Updated Market View assumptions, PA determined that SSJID would need to reinvest excess operating revenue, adjust PG&E rates, and contribute \$39 million of equity up-front and \$15.0 million on average per year over the term of the business plan in order to achieve a flat 15% rate discount to PG&E rates.<sup>26 27</sup>

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<sup>24</sup> Reflects a simple average of annual equity contributions.

<sup>25</sup> PA concluded that with an operational start date of mid-2012 or mid-2014, a flat rate discount of 15% could be achieved by contributing an average of \$14.4 million or \$15.7 million of equity per year over the term of the business plan.

<sup>26</sup> Reflects a simple average of annual equity contributions.

<sup>27</sup> Based on PA's Updated Market View analysis, PA determined that if SSJID contributed an average of \$1.6 million of equity annually instead of \$15.0 million of equity annually over the term of the business plan, it could achieve a flat 6.2% rate discount to PG&E rates.

# 4 Evaluation of Projected Tri-Dam Project Net Revenue

In addition to its new business plan analyses presented in its Supplement, SSJID also presented a projection of SSJID's share in Tri-Dam Project net revenue. PA reviewed SSJID's projection of SSJID's share in Tri-Dam Project net revenue and produced its own forecast of SSJID's share in projected Tri-Dam Project net revenue based on its May 2010 Report assumptions and its Updated Market View assumptions. In this Section, PA first discusses its analysis of SSJID's share in projected Tri-Dam Project net revenue based on its May 2010 Report assumptions, and then discusses its analysis of SSJID's share in projected Tri-Dam Project net revenue based on its Updated Market View assumptions.

## 4.1 Overview of Tri-Dam Project and Assets

The Tri-Dam Project is a joint-venture between Oakdale Irrigation District (Oakdale) and SSJID, created in 1948. Through the Tri-Dam Project, Oakdale and SSJID jointly and equally developed, own and operate three hydropower plants and related storage and water diversion facilities.<sup>28</sup>

The characteristics of the Tri-Dam Project's three hydropower assets are detailed in Table 10 below.

**Table 10: Tri-Dam Project Assets**

Plant Name	Owner	Original Operating Capacity (MWs)	Facility Upgrades (MWs)	Generation Technology	Primary Fuel Type	State	In-service Year
<b>Beardsley</b>	Oakdale & SSJID	11	n/a	Hydraulic Turbine	Water	CA	1957
<b>Donnells</b>	Oakdale & SSJID	72	8	Hydraulic Turbine	Water	CA	1957
<b>Tulloch</b>	Oakdale & SSJID	18	7	Hydraulic Turbine	Water	CA	1958

Sources: SSJID and SNL

Historically, the Tri-Dam Project's electricity output was sold to PG&E, though this contract was terminated as of December 31, 2008. The Tri-Dam Project entered into a new contract as of January 1, 2009 with Shell Energy North America (SENA) for a five-year power purchase and energy production marketing services agreement. The power marketing agreement includes a commission to SENA based on actual revenues.

<sup>28</sup> Separately but similarly, the Tri-Dam Power Authority (Authority) is a joint-venture between Oakdale and SSJID, formed in 1982. The Authority oversees the generation and transmission for the Sandbar Hydropower facility (Sandbar). As SSJID did not provide a forecast of Authority net revenue, PA has not analyzed or projected net revenue for this asset.

## 4.2 Impact of PA Power Price Projections on Tri-Dam Project Net Revenue based on May 2010 Report Assumptions

### 4.2.1 PA's determination of annual net revenue for the Tri-Dam Project

As part of its Supplement, SSJID provided a forecast of SSJID's share in Tri-Dam Project net revenue based on PA's power costs. In this regard, SSJID determined that SSJID's share in the Tri-Dam Project could generate an average of approximately \$18 million of net revenue per year, over the time period of 2011 to 2020.<sup>29</sup>

PA reviewed SSJID's net revenue forecast for the Tri-Dam Project and created its own net revenue model utilizing a combination of data provided by SSJID, public data sources, and PA's standard methodologies. PA's net revenue forecast inputs and methodologies differ in some respects to SSJID's, which results in different projections of net revenue for the Tri-Dam Project. The primary differences include:

- **Capacity for Resource Adequacy (RA):** PA based the total capacity from the hydro units as the Net Qualifying Capacity (NQC) reported by the California Energy Commission. To account for the facility upgrades at Donnell's and Tulloch, PA added the additional capacity to the RA NQC for both plants in 2012 and beyond at the same proportion as recognized for the initial capacity by the CAISO in 2011.
- **Ancillary service projections:** PA utilized its own ancillary services' price projections in its analysis and incorporated the capacity uprate at Donnell's.
- **Hourly operations and super-peak hours:** PA developed an estimate, based on historical operations of Donnell's, of the peak hours of operation for the plant. PA then applied a corresponding price premium for this subset of peak hours, to derive peak hour's energy sales revenue.
- **Projection of O&M expenses** PA projected O&M expenses based on information from SSJID, as well as information from the Tri-Dam Project 2009 Annual Report.

PA concludes that SSJID's share in the Tri-Dam Project could generate \$20.1 million of net revenue on average per year, over the time period of 2011 to 2020, as shown in Table 11 below.<sup>30</sup>

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<sup>29</sup> Reflects a simple average of the 2011 to 2020 annual net revenue projection.

<sup>30</sup> PA forecasted net revenue from the Tri-Dam Project on a cash basis; excluding non-cash items such as depreciation and amortization.

**Table 11: PA Projection of Tri-Dam Project Net Revenue (\$MM, unless otherwise specified)**

Year	Generation (GWh)	Energy Sales Revenue	Ancillary Revenue	REC Revenue	RA Revenue	Total Revenue	Expenses (O&M, ISO Charges, & SENA Fees)	Net Revenue
2011	492	\$25.5	\$2.3	\$1.0	\$2.9	\$31.7	\$(14.5)	\$17.2
2012	529	\$27.9	\$2.3	\$1.2	\$4.0	\$35.4	\$(10.5)	\$24.9
2013	529	\$31.2	\$2.6	\$7.7	\$4.3	\$45.7	\$(11.3)	\$34.4
2014	529	\$32.7	\$2.7	\$6.3	\$12.8	\$54.4	\$(12.1)	\$42.3
2015	529	\$34.1	\$2.8	\$6.1	\$13.0	\$56.0	\$(12.4)	\$43.6
2016	529	\$36.1	\$3.0	\$5.7	\$13.3	\$58.0	\$(12.7)	\$45.3
2017	529	\$37.2	\$3.0	\$5.6	\$13.5	\$59.4	\$(13.0)	\$46.4
2018	529	\$39.1	\$3.1	\$5.4	\$13.7	\$61.3	\$(13.3)	\$48.0
2019	529	\$40.5	\$3.2	\$5.0	\$14.0	\$62.8	\$(13.5)	\$49.3
2020	529	\$41.1	\$3.3	\$5.0	\$14.2	\$63.7	\$(13.8)	\$49.9
<b>Ten-Year Average<sup>1</sup></b>								<b>\$40.1</b>
<b>SSJID Share (50%)</b>								<b>\$20.1</b>

<sup>1</sup> Reflects a simple average of the 2011 to 2020 annual net revenue projection.

## 4.3 Impact of PA Power Price Projections on Tri-Dam Project Net Revenue based on Updated Market View Assumptions

### 4.3.1 PA's determination of annual net revenues for the Tri-Dam Project

PA also performed its analysis of SSJID's share in forecasted Tri-Dam Project net revenue utilizing its Updated Market View. PA updated its model as developed for its analysis in Section 4.2 by updating its forecast of power prices, REC prices and ancillary services prices. These pricing updates reflect PA's price projections as of November 30, 2010. PA's analysis indicates that SSJID's share in the Tri-Dam Project could produce \$18.3 million per year of net revenue, over the time period of 2011 to 2020, as shown in Table 12 below.<sup>31</sup>

<sup>31</sup> PA forecasted net revenue from the Tri-Dam Project on a cash basis; excluding non-cash items such as depreciation and amortization.

**Table 12: PA Projection of Tri-Dam Project Net Revenue (\$MM, unless otherwise specified)**

Year	Generation (GWh)	Energy Sales Revenue	Ancillary Revenue	REC Revenue	RA Revenue	Total Revenue	Expenses (O&M, ISO Charges, & SENA Fees)	Net Revenue
2011	492	\$18.8	\$1.6	\$2.9	\$2.9	\$26.2	\$(14.2)	\$12.0
2012	529	\$24.3	\$1.9	\$2.5	\$3.9	\$32.6	\$(10.4)	\$22.2
2013	529	\$26.3	\$2.0	\$8.8	\$4.6	\$41.7	\$(11.1)	\$30.7
2014	529	\$28.8	\$2.2	\$8.3	\$4.7	\$44.0	\$(11.4)	\$32.6
2015	529	\$31.5	\$2.4	\$6.8	\$13.2	\$53.9	\$(12.2)	\$41.7
2016	529	\$32.7	\$2.5	\$6.8	\$13.4	\$55.4	\$(12.5)	\$42.9
2017	529	\$34.2	\$2.6	\$6.6	\$13.6	\$57.0	\$(12.8)	\$44.2
2018	529	\$34.9	\$2.6	\$6.7	\$13.9	\$58.2	\$(13.0)	\$45.1
2019	529	\$36.9	\$2.7	\$6.5	\$14.1	\$60.3	\$(13.4)	\$46.9
2020	529	\$38.2	\$2.9	\$6.4	\$14.4	\$61.9	\$(13.7)	\$48.2
<b>Ten-Year Average<sup>1</sup></b>								<b>\$36.6</b>
<b>SSJID Share (50%)</b>								<b>\$18.3</b>

<sup>1</sup> Reflects a simple average of the 2011 to 2020 annual net revenue projection.

# Appendix A: Detailed Assumptions from Updated Market View Business Plan Analysis

**Table 13: Total Rates (\$/kWh) - Inflated at 1.8%**

Year	Industrial	Small Commercial	Large Commercial	Residential	Agriculture	Street Lighting
2013	0.13827	0.18566	0.16319	0.17521	0.18096	0.14858
2014	0.14076	0.18901	0.16613	0.17837	0.18422	0.15126
2015	0.14330	0.19241	0.16912	0.18158	0.18754	0.15398
2016	0.14588	0.19587	0.17216	0.18485	0.19091	0.15675
2017	0.14850	0.19940	0.17526	0.18817	0.19435	0.15957
2018	0.15118	0.20299	0.17841	0.19156	0.19785	0.16244
2019	0.15390	0.20664	0.18163	0.19501	0.20141	0.16537
2020	0.15667	0.21036	0.18489	0.19852	0.20504	0.16834
2021	0.15949	0.21415	0.18822	0.20209	0.20873	0.17137
2022	0.16236	0.21800	0.19161	0.20573	0.21248	0.17446
2023	0.16528	0.22192	0.19506	0.20943	0.21631	0.17760
2024	0.16825	0.22592	0.19857	0.21320	0.22020	0.18080
2025	0.17128	0.22999	0.20214	0.21704	0.22416	0.18405
2026	0.17437	0.23412	0.20578	0.22095	0.22820	0.18736
2027	0.17750	0.23834	0.20949	0.22492	0.23231	0.19074
2028	0.18070	0.24263	0.21326	0.22897	0.23649	0.19417
2029	0.18395	0.24700	0.21710	0.23309	0.24075	0.19766
2030	0.18726	0.25144	0.22100	0.23729	0.24508	0.20122
2031	0.19063	0.25597	0.22498	0.24156	0.24949	0.20484
2032	0.19407	0.26058	0.22903	0.24591	0.25398	0.20853
2033	0.19756	0.26527	0.23316	0.25033	0.25855	0.21229
2034	0.20111	0.27004	0.23735	0.25484	0.26321	0.21611
2035	0.20474	0.27490	0.24162	0.25943	0.26794	0.22000
2036	0.20842	0.27985	0.24597	0.26410	0.27277	0.22396
2037	0.21217	0.28489	0.25040	0.26885	0.27768	0.22799
2038	0.21599	0.29002	0.25491	0.27369	0.28268	0.23209
2039	0.21988	0.29524	0.25950	0.27862	0.28776	0.23627
2040	0.22384	0.30055	0.26417	0.28363	0.29294	0.24052
2041	0.22787	0.30596	0.26892	0.28874	0.29822	0.24485
2042	0.23197	0.31147	0.27376	0.29393	0.30358	0.24926
2043	0.23614	0.31707	0.27869	0.29923	0.30905	0.25375

**Table 14: Total Rates (\$/kWh) - Inflated utilizing increases from Section 3.2<sup>1</sup>**

Year	Industrial	Small Commercial	Large Commercial	Residential	Agriculture	Street Lighting
2013	0.13954	0.18737	0.16468	0.17682	0.18262	0.14994
2014	0.14501	0.19471	0.17114	0.18375	0.18978	0.15582
2015	0.15076	0.20243	0.17793	0.19104	0.19731	0.16200
2016	0.15404	0.20684	0.18180	0.19519	0.20160	0.16552
2017	0.15718	0.21105	0.18550	0.19917	0.20571	0.16890
2018	0.15982	0.21459	0.18862	0.20252	0.20916	0.17173
2019	0.16408	0.22032	0.19365	0.20791	0.21474	0.17631
2020	0.16834	0.22603	0.19867	0.21331	0.22031	0.18088
2021	0.17071	0.22921	0.20147	0.21631	0.22341	0.18343
2022	0.17375	0.23330	0.20505	0.22016	0.22739	0.18670
2023	0.17634	0.23678	0.20812	0.22345	0.23079	0.18949
2024	0.17911	0.24050	0.21139	0.22696	0.23441	0.19246
2025	0.18163	0.24387	0.21435	0.23015	0.23770	0.19517
2026	0.18491	0.24828	0.21823	0.23431	0.24200	0.19870
2027	0.18809	0.25255	0.22198	0.23834	0.24616	0.20211
2028	0.19094	0.25638	0.22534	0.24194	0.24989	0.20517
2029	0.19431	0.26090	0.22932	0.24622	0.25430	0.20879
2030	0.19674	0.26416	0.23218	0.24929	0.25748	0.21140
2031	0.19939	0.26773	0.23532	0.25266	0.26095	0.21425
2032	0.20209	0.27135	0.23850	0.25608	0.26448	0.21715
2033	0.20484	0.27504	0.24174	0.25956	0.26808	0.22011
2034	0.20763	0.27879	0.24504	0.26310	0.27173	0.22311
2035	0.21047	0.28260	0.24839	0.26670	0.27545	0.22616
2036	0.21336	0.28649	0.25181	0.27036	0.27924	0.22927
2037	0.21630	0.29043	0.25528	0.27408	0.28308	0.23243
2038	0.21929	0.29445	0.25880	0.27787	0.28700	0.23564
2039	0.22233	0.29853	0.26239	0.28173	0.29098	0.23891
2040	0.22543	0.30269	0.26605	0.28565	0.29503	0.24223
2041	0.22858	0.30691	0.26976	0.28964	0.29915	0.24561
2042	0.23178	0.31121	0.27354	0.29370	0.30334	0.24906
2043	0.23503	0.31559	0.27738	0.29782	0.30760	0.25255

<sup>1</sup> It is important to note that PA's analysis only focuses on selected changes to power supply costs and is not intended to reflect a full study and forecast of PG&E's rates, but rather to serve as a proxy to reflect the impact of PA's projected power price projections on PG&E's rates.

# Appendix B: Fundamental Market Assumptions

This Section describes the fundamental market assumptions used by PA to model the WECC-CA market. PA relied on fundamental energy market projections as of November 30, 2010 for its study period.<sup>32</sup>

PA data and assumptions are input into a production cost model to project fundamental energy prices and input into PA's proprietary capacity compensation model to project fundamental capacity prices. Additional information about PA's modeling approach is included in Appendix C.

## B.1 Supply and Demand

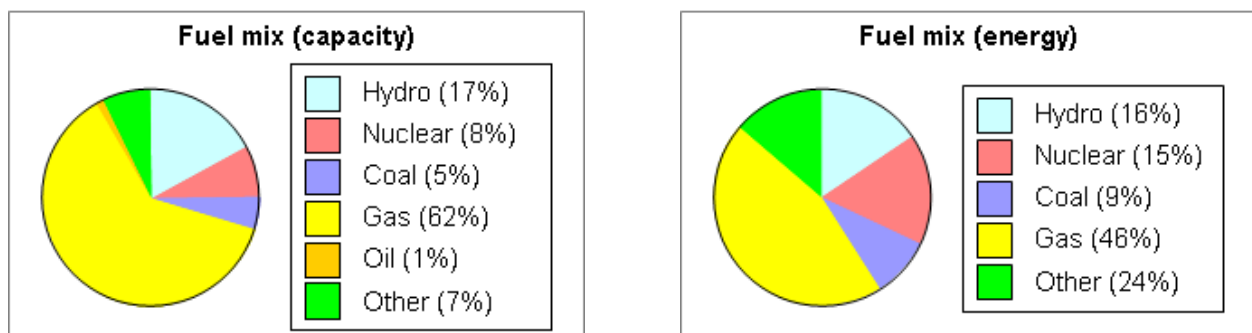
Supply assumptions impact the timing of market equilibrium, and associated returns on investment costs, in the market. The mix of supply within a given market is also an important variable. All else equal, the fewer baseload resources (such as nuclear, hydroelectric, and other renewable capacity) installed within a given market, the higher the capacity factor and gross margin for a natural gas power generating asset.

### B.1.1 WECC-CA supply

The entire WECC-CA region has approximately 73,000 MW of existing supply, and it is projected to have approximately 1,000 MW of pre-equilibrium supply retirements and 4,700 MW of nameplate capacity additions<sup>33</sup> during the 2011 to 2014 time period.

In 2013, approximately 62% of the projected installed capacity is natural gas, which is expected to account for about 46% of the region's energy production at that time. Hydro and nuclear also make significant contributions to California's energy production. WECC-CA's fuel mix is shown in Figure 5 below.

Figure 5: Fuel Mix, Capacity and Energy<sup>1</sup> - WECC-CA - 2013



<sup>1</sup> May not sum to zero due to rounding.

<sup>32</sup> For years 2031 forward, PA assumed market prices increase at an annual inflation rate of 1.8%.

<sup>33</sup> Renewable capacity additions are subject to capacity derates for reliability planning purposes.

## B.1.2 WECC-CA demand

The demand assumptions directly impact the timing of market equilibrium, and associated returns on investment cost, in the region. Peak demand growth represents the increase in required supply to meet demand including reserve margin during the hour of highest demand during the year, while energy growth represents the total energy generation required to meet demand over the course of the year. See Table 15 for a summary of the compound annual average growth rates of peak demand and energy for the WECC-CA market.

**Table 15: Projected Average Annual Growth Rates (2013-2027)**

Market	Demand	Energy
WECC-CA	1.22%	1.12%

Sources: PA Consulting Group analysis, California Energy Demand Report 2010-2020

Table 16 shows the supply-demand projections from 2013 to 2027.

**Table 16: Supply and Demand Projections (GW) - WECC-CA - 2013 through 2027**

GW	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
2012 supply <sup>1</sup>	72.8														
Combined cycle	0.0	0.6	0.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.5	0.0	0.0	0.5
Combustion turbine	0.7	0.0	0.7	1.7	0.7	5.2	0.7	1.0	1.0	0.7	5.9	0.3	1.0	0.7	0.0
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewables <sup>2</sup>	0.1	0.1	0.2	0.1	0.3	0.1	0.3	0.8	0.1	0.1	0.9	0.1	0.2	0.3	0.3
Imports/exports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSRs	0.2	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Retirements	-0.1	0.0	-0.7	-1.5	0.0	-4.5	0.0	-1.1	0.0	0.0	-6.4	0.0	0.0	0.0	0.0
Total Supply	73.7	74.5	74.8	75.7	76.8	77.7	78.8	79.5	80.7	81.6	82.5	83.5	84.8	85.8	86.6
Peak demand <sup>3</sup>	63.5	64.3	65.0	65.8	66.6	67.4	68.2	69.1	69.9	70.8	71.7	72.5	73.4	74.3	75.2
Load growth (%)		1.2	1.2	1.2	1.3	1.2	1.2	1.3	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Reserve margin (%)	16.0	15.9	15.0	15.1	15.3	15.2	15.4	15.1	15.4	15.2	15.1	15.0	15.4	15.4	15.1

<sup>1</sup> Includes over 4 GW of demand side management and energy efficiency.

<sup>2</sup> Wind capacity is derated to 10% of nameplate capacity.

<sup>3</sup> Peak demand and load growth numbers through 2020 are from the California Energy Demand 2010-2020 Report. Years 2021-2030 use a five-year average growth rate.

## B.2 Fuel Pricing

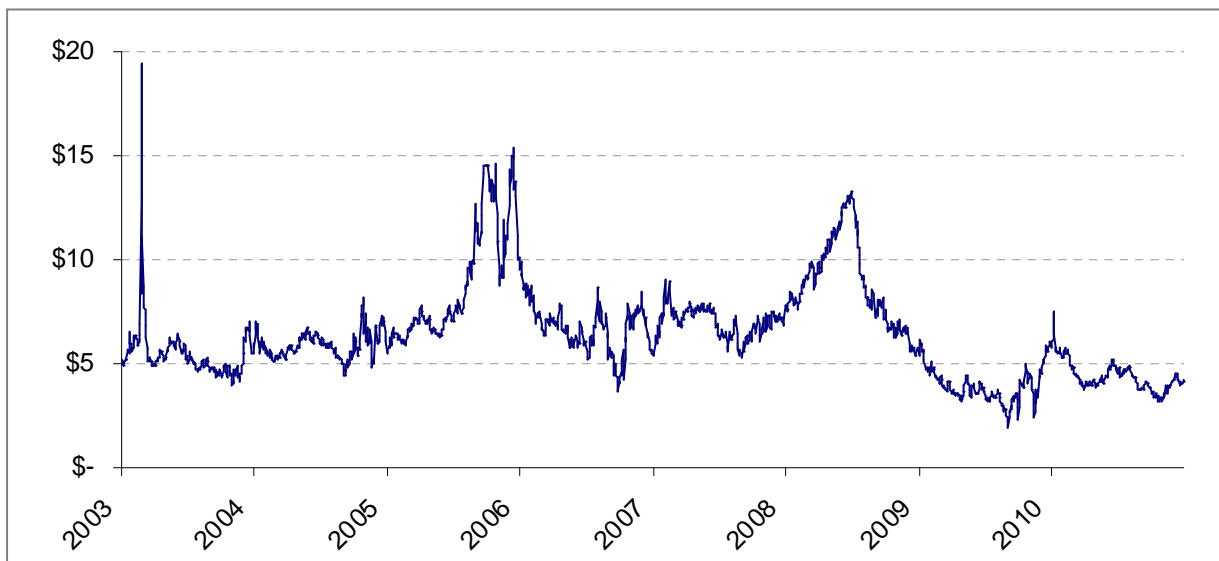
Fuel assumptions impact the variable costs of most power generating assets available for operation within PA’s fundamental model. Fuel costs of primary importance to a region’s power prices include natural gas, fuel oil, and coal. Natural gas power generating assets have historically set the market clearing price for electricity during the majority of hours in the WECC-CA market, as discussed above.

### B.2.1 Natural gas

Fuel assumptions impact the assumed variable costs of each power generating asset available for operation within PA’s fundamental model. Fuel costs of primary importance to a region’s power prices include natural gas, fuel oil, and coal. Natural gas and coal prices are the two primary assumptions covered in this Section, because natural gas and coal-fired assets set the market clearing price for energy during the majority of hours. Fuel oil rarely sets the market clearing price.

The U.S. natural gas market has experienced unprecedented volatility in recent years. Figure 6 shows Henry Hub natural gas prices from 2003 through December 2010.

**Figure 6: Henry Hub Natural Gas Prices: January 2003 through December 2010 (nominal \$/MMBtu)**



Source: Bloomberg.

Delivered natural gas prices are based on PA’s market-by-market view of regional and local transportation, demand seasonality and spot basis differentials to the Henry Hub. The Henry Hub price is an average derived from projections published by the EIA, Global Insight, and SEER

Table 17 shows the delivered natural gas price in WECC-CA NP-15.

**Table 17: Delivered Natural Gas Price - WECC-CA NP-15 (nominal \$/MMBtu)**

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
5.55	6.02	6.52	6.65	6.74	6.88	7.11	7.34	7.54	7.79	8.01	8.15	8.33	8.53	8.77

Delivered natural gas price projections include commodity price, transportation rate, and applicable taxes.

## B.3 Emission Allowance Prices

Emission allowance prices impact the assumed variable costs of coal, natural gas, and fuel oil power generating assets available for operation within PA's fundamental model. As such, allowance prices impact the variable cost differences between assets in the dispatch merit order. Price projections for Federal and WCI CO2 are presented in Table 18 below.

**Table 18: Emission Allowance Prices (nominal \$)**

Year	Federal CO2 (\$/short ton) <sup>1</sup>	WCI CO2 (\$/short ton) <sup>1</sup>
2013		9.88
2014		10.95
2015		12.13
2016		13.42
2017		14.88
2018	15.00	
2019	16.08	
2020	17.23	
2021	18.46	
2022	19.80	
2023	21.21	
2024	22.73	
2025	24.37	
2026	26.12	
2027	27.99	

<sup>1</sup> One short ton = 0.9072 metric tons.

## B.4 Financial Parameters

New plant construction costs (also referred to as capital costs) help define the premium a market places on capacity, particularly at and beyond market equilibrium. New capacity is unlikely to be built in the market unless it will recover its investment costs (including returns). Therefore the market should allow for recovery of investment cost over the long run to assure adequate capacity is installed for reliability purposes. It should be noted that investment opportunities change as market dynamics evolve. The net breakeven cost of building a new combustion turbine facility is considered to set the ceiling on compensation for capacity. Table 19 details PA's capital cost assumptions applied in modeling new power generating assets.

**Table 19: Generic Unit Assumptions**

Assumptions	Combined Cycle (CC)	Combustion Turbine (CT)
Capacity (MW)	520	345
Installed capital cost (2013 \$/kW) <sup>1</sup>	1,260	740
Full load heat rate (Btu/kWh) <sup>2</sup>	6,950	10,712
Fixed O&M (2013 \$/kW)	16.90	8.05
Variable O&M (2013 \$/MWh)	2.80	7.05

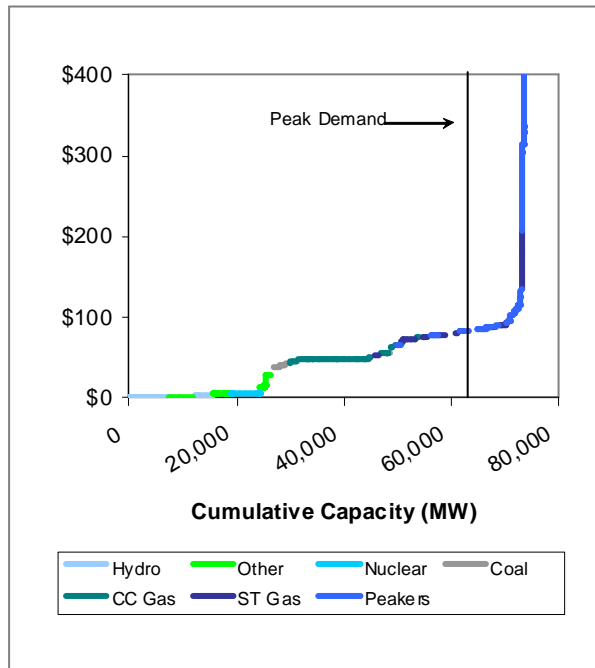
<sup>1</sup> Capital cost to bring a new generation asset online in 2013 (cost is in 2013 \$/kW-year)

<sup>2</sup> Winter heat rates listed. Summer heat rates are 1.5% higher for a CC, and 2.9% higher for a CT.

## B.5 Dispatch Merit Order Curve

A dispatch merit order curve, or dispatch curve, illustrates power generating assets in order of their individual variable cost of operation, or dispatch.<sup>34</sup> The dispatch curve in Figure 7 shows the annual average, short-run marginal dispatch cost of power generating assets located in the WECC-CA market in 2013.

**Figure 7: Dispatch Merit Order Curve - WECC-CA - 2013 (nominal \$/MWh)**



<sup>34</sup> Variable cost of operation, or dispatch, includes fuel, operating and maintenance, and emission allowance costs associated with a given power generating asset's dispatch.

# Appendix C: Modeling Methodology

## C.1 Introduction

PA uses a bottom up approach to forecasting market electricity prices and power generating asset cash flows. This process is formed around a fundamental analysis. As part of the fundamental analysis, PA develops assumptions using an approach that continuously combines research, data and industry knowledge. PA translates the insight gained from published industry data and its proprietary inputs into modeling inputs, thus power generating asset results. PA also analyzes power generating asset results from its fundamental analysis by applying its own proprietary stochastic dispatch optimization model and current configuration of a locational marginal pricing model to assess the impacts of price volatility and transmission constraints, respectively.

## C.2 Core Principles

Two principles are fundamental to PA's approach:

- **Supply and demand equilibrium:** Power markets migrate toward a balance between capacity and load.
- **Compensation for generation:** Generators are compensated for more than the marginal cost of generation.

### C.2.1 Supply and demand equilibrium

A fundamental tenet of PA's approach is that market participants continuously adjust toward economic equilibrium conditions by making decisions to add or retire generating capacity. Participants respond to the opportunity to capture excess margins through entry and the inverse opportunity to exit when expected returns do not justify ongoing costs. As a consequence, neither excessively high nor excessively low returns should persist over the long-term, because participants will change the level of supply until a balance with demand is reached. While PA believes that markets gravitate toward equilibrium conditions, participants often react to both below- and above-market returns causing pendulum-like price variations over time.<sup>35</sup>

### C.2.2 Compensation for generation

PA's analysis utilizes a market model based on the premise that generators are compensated for more than the marginal cost of energy. PA's approach forecasts additional compensation (above marginal cost) for the going-forward costs of generation (i.e. costs of generation that are not sunk) to maintain system reliability. In a deficit or equilibrium market, this compensation would include the cost of debt and equity

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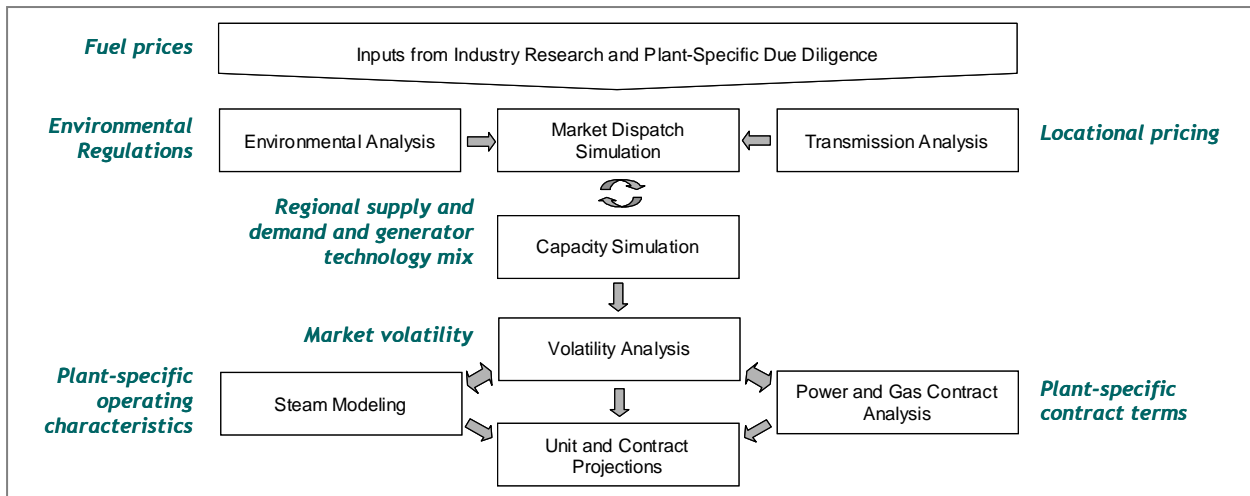
<sup>35</sup> Actual markets rarely achieve precise equilibrium. Many industries have shown a pendulum of cycling returns, where above-market returns are followed by excess entry resulting in lower returns, followed by under-investment, which in time yields higher returns. While such cycles are often characteristic of commodity markets, the market generally seeks economic equilibrium.

required to build the necessary units for system reliability requirements. This compensation could come in the form of energy payments (in spot, forward, and bilateral markets), capacity payments (installed capacity or ICAP, unforced capacity or UCAP, RA, and bilateral payments), and ancillary service payments.

### C.3 Key Components of the Analysis

PA employs a variety of models to forecast market prices in regional markets and project the performance of power generating assets. The approach and the types of models used are widely accepted and commonly relied upon in the energy industry to forecast asset cash flows. The key components of the analysis are illustrated in Figure 8.

**Figure 8: Key Components of the Modeling Process**



The central components of PA’s analysis are the simulation of plant dispatch operations (“Market Dispatch Simulation” on the diagram) and capacity additions and retirements (“Capacity Simulation” on the diagram). Multiple inputs drawn from industry research also shape the analysis.

#### C.3.1 Environmental analysis (emissions)

Environmental regulations force generators to incur costs to comply with limits on emissions of certain pollutants, generally reducing cash flows. PA uses its proprietary Multi-Pollutant Optimization Model (MPOM) to project the costs of these regulations.

PA’s forecast reflects the costs and constraints of a multi-pollutant regulatory scenario, which includes restrictions on sulfur dioxide (SO<sub>2</sub>), nitrogen oxides (NO<sub>x</sub>), mercury (Hg) and CO<sub>2</sub> emissions. In this context, PA projects:

- the optimal timing and type of environmental capital expenditures (given the trade-off between expensive environmentally efficient equipment and higher emissions costs).
- the optimal fuel type for each plant (given the trade-off between cleaner fuel and higher emissions costs).

- emission cost rates for the pollutants (given volumetric caps imposed by regulation).

MPOM is a model that solves for the optimal market-driven decisions to comply with emissions constraints and maximize cash flows over the long term.

Beyond the near term (when forward prices are used), the prices for NO<sub>x</sub> and SO<sub>2</sub> emissions allowances are outputs of this model based on the current regulations in place. CO<sub>2</sub> pricing is derived based on an analysis of proposed legislation. The prices and decisions associated with all environmental programs are used as an environmental cost in the dispatch of generating units.

### **C.3.2 Environmental analysis (renewable energy)**

The REC market has emerged as a way for renewable generators to capture additional payments for the green attributes of their energy production. In general, a REC is defined as one megawatt-hour of renewable energy generation delivered to the electric power system. RECs are purchased by load-serving entities, often to satisfy RPS.

PA projects REC prices based on the additional revenue needed (above and beyond revenues earned from the energy market) for the lowest cost renewable resource needed to meet RPS requirements. Main drivers to the REC price forecast include:

- market energy prices
- transmission constraints
- the type and amount of renewable resources that can be built in a region
- renewable tax incentives
- technology development costs.

PA's REC price modeling approach involves projecting demand for renewable energy based on the projected electricity sales for the load serving entities and the RPS annual goals. For each year of the forecast, a cash flow is developed for renewable resources to determine project revenues and to calculate the REC price sufficient for a renewable project to break even. In early years, transmission limitations restrict the amount of renewable resources that can be added in addition to the amount of planning and construction time required for resources to be brought into service.

The REC forecast is determined by identifying the required REC payment for the marginal technology needed to meet the RPS goal. The identification is accomplished by comparing the renewable supply stack, sorted from low to high cost technologies, to the RPS demand in each year. For most years, wind generation is expected to be the marginal resource and thus set the REC price. In the early years, the REC price reflects current market prices.

### **C.3.3 Transmission analysis**

Transmission limitations introduce power price disparities within a region, and these price disparities affect cash flows. For favorably located units (for instance, within an area of high demand but limited access to supply due to transmission constraints, such as Southwest Connecticut), these disparities increase gross margins. For unfavorably located plants (for instance, within an area of low demand and minimal transmission access to areas of high demand), these price disparities reduce gross margins.

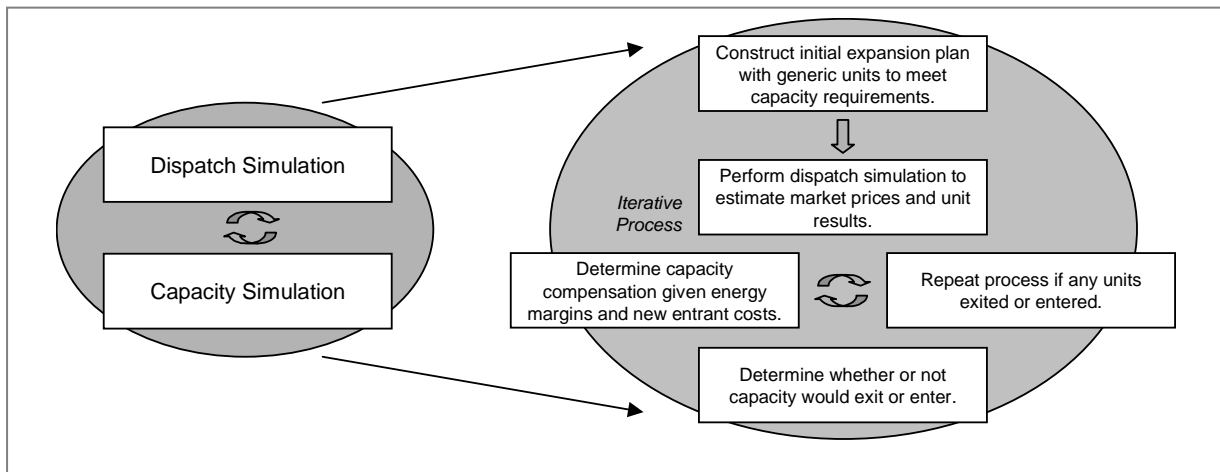
PA employs its transmission expertise and conducts power flow modeling analysis to assess the intrazonal transmission congestion and constraints that a given power generating asset is projected to encounter.

### C.3.4 Dispatch simulation

Power plants are dispatched to generate and sell power when demand justifies the operating costs. Units with low operating costs relative to other facilities are dispatched often; units with high costs are dispatched less frequently. The hour-by-hour interaction of supply and demand determines how frequently and how profitably plants dispatch within a market, and simulating this interaction is a modeling approach that is commonly relied upon in the industry to forecast cash flows.

An iterative process of dispatch and capacity simulation is at the core of PA’s methodology. After PA specifies an initial capacity plan to satisfy the load projections, PA’s model simulates the behavior of the regional power markets and the corresponding dispatch decisions of the power generating asset. PA’s model then simulates the decisions market participants would make to add or retire capacity given the performance of the plants. Figure 9 illustrates the iterative process.

**Figure 9: Iterative Dispatch and Capacity Simulation**



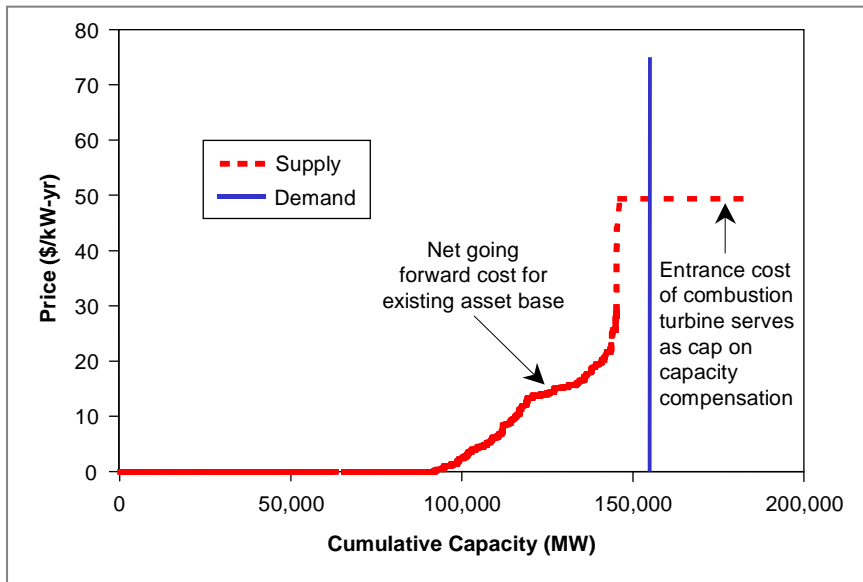
The dispatch of the regional markets is simulated using MULTISYMTM, an hour-by-hour chronological production cost-based dispatch model. Within MULTISYMTM, generating units in each pertinent transmission area are modeled individually, taking into account the unit-specific cost and operating characteristics. Units are dispatched in the simulation in the order of economic merit (according to dispatch cost) until adequate generation is brought online. The cost of the last unit dispatched to meet load requirements sets the power price for that hour.

The products of the dispatch simulation are energy price forecasts for the regional power markets and performance statistics for each of the generating units (such as capacity factors and gross margin).

### C.3.5 Capacity simulation

The remaining steps of the dispatch and capacity simulation (see Figure 10 below) relate to the decisions market participants make regarding capacity entry and exit.

**Figure 10: Example Supply and Demand Curve**



Plants that continue to lose money will eventually be retired. Conversely, market participants who perceive the opportunity for an attractive investment return will undertake to construct new plants. Both of these dynamics will change the power markets over time and affect the earnings prospects for a given power generating asset.

### **Capacity Compensation simulation**

The difference between the energy margins produced by the dispatch analysis and the going-forward costs drives the amount of additional compensation necessary to motivate generators to provide capacity (PA defines this as capacity compensation).<sup>36</sup>

PA's capacity compensation model assumes that each regional market will retain a sufficient amount of capacity to meet reliability requirements. The intersection between capacity supply and demand determines the rate for capacity compensation.

### **Capacity additions and retirements**

Over the projection period, each regional supply mix changes due to capacity additions and retirements.

- For the near-term, capacity changes are based on PA's assessment of public information regarding retirements and additions. PA excludes construction projects that have been announced but not yet financed, permitted, or started.
- For the long-term, capacity changes are a function of projected returns. Units that expect to lose money for five consecutive years are retired at the end of the third losing year. New units are added if the projected energy and capacity margins provide an adequate investment return.

<sup>36</sup> Going-forward costs are the fixed costs that could be avoided with unit shutdown, i.e. the costs exclusive of sunk capital or financing costs.

The resulting supply mix then becomes the basis for another dispatch model run. This process is repeated until retirements and additions converge, marking the end of the dispatch and capacity simulation process.

### **C.3.6 Volatility analysis**

Electricity prices are highly unpredictable due to physical characteristics (non-storability) and network dynamics (unpredictable load, generation and transmission outages, etc.). Price volatility may impact energy margins, particularly for some types of units.

PA assesses the impact of volatility on specific power generating assets by using its proprietary stochastic dispatch model. This model is designed to simulate market price volatility and plant operating decisions made in the context of uncertainty. The results of the stochastic dispatch include plant operations and gross margin projections.

## **C.4 Conclusions**

PA has extensive experience projecting the operations and gross margin of physical power generating assets and marking related financial assets to market for the purposes of debt financing, acquisition support, business planning, litigation support, portfolio optimization, restructuring and sales. PA has analyzed physical and financial assets in nearly every North American power market.

PA employs an industry leading modeling approach that leverages the knowledge of its subject matter experts and utilizes a unique mix of integrated modeling capabilities. Specifically:

- PA has experts in power market economics, operations and modeling, emissions regulation and modeling, transmission analysis, oil and natural gas markets, and renewable markets, among others. PA leverages this expertise to offer an integrated view of the energy markets and to support its proprietary modeling suite.
- PA has a robust, well-developed, and industry-tested fundamental modeling process, including its proprietary stochastic dispatch optimization, capacity compensation, environmental, renewable, and valuation models along with the use of production cost, transmission, and natural gas models that are operated by PA experts and populated with PA data.

# Appendix D: Sources of Information

PA's opinions set forth herein are based on information provided by PG&E, SSJID, other information generally available to PA, and studies and analyses undertaken by PA, all of which are basic to and in support of our opinions. The documents relied upon include:

## **PG&E Sources:**

- PG&E FERC Form 1, 2009
- Microsoft Excel SSJID Hourly Load Profile, 2-10-2011
- Microsoft Excel SSJID Historical 2008 and 2010 Sales Data
- PG&E Transferred Municipal Departing Load Electric Rate Schedule E-TMDL, and related PG&E website information
- PG&E 2011 General Rate Case Joint Comparison Exhibit
- PG&E 2011 Energy Resource Recovery Account Forecast Ongoing Competition Transition Charge Forecast Revenue Requirement and Associated Rates, November 5, 2010
- Advice Letter 3603-E-A, February 25, 2010
- Advice Letter 3727-E-A, December 30, 2010
- PG&E's August 2010 RPS Compliance Report
- PG&E's 2009 Electricity Resource Planning Form S-1 and S-2
- PG&E's March 2010 RPS Compliance Report, March 1, 2010
- PG&E's August 2010 RPS Compliance Report, August 2, 2010

## **SSJID Sources:**

- SSJID Supplement to the Application to San Joaquin LAFCo, September, 2010
- SSJID Microsoft Excel Business Plan Model
- SSJID Microsoft Excel PG&E Rate Increase Model
- SSJID Microsoft Excel Tri-Dam Project Revenue Model
- Multiple Microsoft Excel documents pertaining to Tri-Dam historical operations and financial results

## **PA Sources:**

- PA's market price forecast models

## **Other Sources:**

- California Energy Commission California Energy Demand 2010-2020 Adopted Forecast Commission Report and Adopted Demand Forecast Forms, December 2009
- California ISO GMC Rates for 2004-2011, Effective 1/1/2011
- California ISO NQC Local Area Data for Compliance Year 2011 - Final 07-Dec-2010
- Blue Chip Economic Indicators

- Global Insight 30-year U.S. and Regional Economic Projections
- Fitch Ratings U.S. Public Power Peer Study, June 16, 2010
- California Public Utility Commission Decision 06-07-030, Opinion Regarding Direct Access and Departing Load Cost Responsibility Surcharge Obligations, July 20, 2006
- California Public Utility Commission Decision 08-09-012, Decision on Non-Bypassable Charges for New World Generation and Related Issues, September 4, 2008
- California Public Utility Commission Decision 10-12-006, Decision Allocating the Revised 2011 Revenue Requirement Determination of the California Department of Water Resources, December 2, 2010
- Department of Water Resources Revision to the Determination of Revenue Requirement for the Period January 1, 2011 through December 31, 2011, October 26, 2010
- Department of Water Resources Presentation, Overview of DWR Power Contracts: Background and Review of Portfolio Novation and Assignment to the California Investor-Owned Utilities, June 2, 2008
- Department of Water Resources Energy Contract Website (<http://www.cers.water.ca.gov/>)
- MWH Phase 1: Preliminary Design Report for Tulloch 3rd Unit Generation Addition, September 11, 2006
- Tri-Dam Project Annual Financial Report, 12-31-2009
- Tri-Dam Power Authority Annual Financial Report, 12-31-2009
- Energy Velocity
- DSIRE USA
- SNL

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