Final Report:

Solar Integration Study for Public Service Company of Colorado

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PROJECT TEAM

Xcel Energy ("Company") retained EnerNex Corporation of Knoxville, Tennessee ("EnerNex") for this project to assist the Company in analyzing various aspects of solar integration issues for the Public Service Company of Colorado ("Public Service") system.

EnerNex is an electric power engineering and consulting firm specializing in the development and application of new electric power technologies. EnerNex provides engineering services, consulting, and software development and customization for energy producers, distributors, users, and research organizations. The company has substantial expertise with a broad range of technical issues related to solar and wind generation.

EXECUTIVE SUMMARY

BACKGROUND

In its decision approving, with modifications, Public Service's Colorado Resource Plan ("CRP") (Docket No. 07A-447E), the Colorado Public Utilities Commission ("Commission") directed the Company to investigate the integration costs of intermittent solar generation. This report documents the Company's efforts and results of that investigation. This report addresses integration costs for solar generation levels between 200 and 800 megawatts (MW) of solar nameplate capacity on the Public Service system. The analysis considered various solar generation technologies, natural gas pricing, and geographic location of solar generation facilities.

Methodology

The modeling technique employed in this study is similar to that employed in prior wind integration cost studies provided to the Commission;[1] in those studies, integration costs were assumed to derive from the uncertainties in a real-time operator's day-ahead commit and dispatch decisions. In this study, the modeling technique attempted to quantify the inefficiencies in system dispatch caused by uncertainties in the forecast of solar generated electric energy. The model employed in this study focused on forecasted load and generation on an hourly basis. Several categories of costs can not be captured by this hourly methodology, including: regulation costs, gas supply system costs, increased O&M costs at existing units, and energy trading inefficiencies. In particular, additional system regulation costs incurred by sub-hourly variability in photovoltaic generation were not captured due to a lack of historical sub-hourly solar resource data.

Results

Six scenarios comprising a mix of solar generation technologies, locations, and MW levels were studied in this report; sensitivities to natural gas pricing assumptions were studied for four of the six scenarios. Integration costs for the six base scenarios ranged from $1.25/MWh up to $6.06/MWh. Integration costs for the four gas sensitivity scenarios ranged from -$0.85/MWh up to $9.38/MWh.

Solar integration costs rise with increasing solar penetration at a rate roughly equal to $1.00/MWh for each 100MW (nameplate) of additional solar generation capacity. Integration costs rise with increasing natural gas prices at a rate roughly equal to $1.50/MWh for each $1.00/MMBtu increase in gas cost. As expected, higher levels of geographic diversity tend to reduce integration costs. Given the methodology employed in this analysis, the particular scenarios analyzed, and the lack of sub-hourly solar resource data, no clear trend in solar integration costs were identified between one solar generation technology versus another.

[1] "Final Report: Wind Integration Study for Public Service of Colorado", May 22, 2006. "Final Report: Wind Integration Study for Public Service of Colorado, Addendum, Detailed Analysis of 20% Wind Penetration", October, 2008.

INTRODUCTION

In 2008, Xcel Energy initiated a study of economic impacts of adding significant amounts of solar generation to its Colorado electric supply portfolio. That effort resulted in this report. This report addresses solar generation levels between 200 and 800 megawatts (MW) of solar nameplate capacity on the Public Service system. The analysis considered various solar generation technologies, natural gas pricing, and geographic location of solar generation facilities.

Overview of Project Objectives

The focus of this study was to provide an estimate for the "hidden" costs of integrating solar energy into the Public Service system. These hidden costs are associated with the uncertain and variable nature of solar generation. The integration cost estimates will be used in the resource planning and project selection process to ensure that solar generation is compared on a level playing field with other available resource technologies. The Company does not intend that this study be used as a reliability study. While loss of load risks can be monetized, that is beyond the scope of this study.

Integration Costs quantified in this study

This study only captures one category of integration costs: the electric production costs of operating Public Service's electric generation system (fuel costs, variable and fixed O&M, etc.) It is important to note that several categories of costs were not quantified in this analysis:

1. Regulation Costs – power generated from photovoltaic technology can change very quickly in a short time frame (minute to minute). Since this evaluation only looked at hourly data, costs associated with regulating the Public Service system are not included.
2. Gas Supply System Costs – the study did not quantify costs associated with operating or expanding Public Service's gas supply system due to solar.
3. Increased O&M costs – existing thermal units may be called upon more often to ramp output over a broader range with shorter notice as a result of the variability in solar power output. This study does not attempt to estimate costs associated with increased operation and maintenance costs for these units.
4. Other costs – this study does not attempt to quantify any integration costs associated with transmission expansion costs or electricity trading inefficiencies introduced by solar uncertainty.

Given the diurnal nature of the solar resource, the variability of solar generation on the Public Service system is absorbed by natural gas-fired generation. Thus, a significant positive correlation between increasing natural gas pricing and intermittent solar generation is expected.

Models and Data

For this study, EnerNex selected an existing commitment and dispatch model representing the Public Service electric generation system in 2007. The 2007 base year was represented with:

- A (modified) projected peak load of 6,922 MW
- Projected energy requirements of 34,224 GWH
- Approximately 15 MW of customer-sited solar electric power

The chronological simulation methodology used in this study requires extended sets of hourly data. The preference is for this data to be based on recent historical information so that the daily load patterns are most representative of the recent behavior of actual system loads. In this vein, it is also important that the chronological solar generation data be drawn from the same historical year so that correlations between intermittent resources and hourly load due to meteorology are properly represented in the input data.

Historical load data from three years—2002, 2003, and 2004—were used to develop the hourly load patterns. The data sets were scaled so that the peak hour matched that projected for the year 2007.

Other data used to define the study year, included:

- Day-ahead forecasts of hourly load, which were used for forward scheduling and power marketing activities in addition to nomination of natural gas for both direct use and gas-fired generation,
- Planned, maintenance, and forced outage history for generating units,
- Meteorological data (i.e., the intensity of the solar resource measured in watts/meter^2), used to construct an hour-by-hour production pattern for the solar electric resources on the Public Service system.

Assumptions

This study used the Global Energy Solutions' Couger model to simulate the economic commitment and dispatch of the Public Service electric supply system. Couger is a unit commitment and dispatch model that has been used by Xcel's Power Operations group for establishing day-ahead dispatch plans for the Company's electric systems. Couger was used to mimic the day-ahead activities that system operators use to develop the best plan for meeting the load requirements of the system for the next day (i.e., the "day-ahead" plan).

The model does not attempt to account for transmission constraints or losses. All of the solar energy from each solar plant was assumed to reach the Public Service system to help serve customer load. The geographic location of solar facilities is only relevant in that it represents a particular solar pattern and hourly electricity production profile.

The solar energy is modeled as a predetermined hourly energy production profile and entered into the Couger model as a "must take" resource. This is the same technique that has been used for modeling wind in all previous integration cost studies performed for the Public Service system.

Other assumptions include:

1) New Thermal Resources Added (as substitute for solar if needed)
    a. Type = Three (3) Generic Combustion Turbines in 2007
    b. Ratings - Summer = 120 MW (each); Winter = 139 MW (each)
    c. Heat Rate = 10,450 MMBTU/MWh
    d. Variable O&M = $4.30/MWh
    e. Fixed O&M = $ 10.74 kW-yr (based on 160 MW design)
    f. Min/Max Loading
        i. 25% = 17, 568 MMBTU/MWH
        ii. 50% = 12,759 MMBTU/MWH
        iii. 75% = 11,204 MMBTU/MWH
        iv. 100% = 10,450 MMBTU/MWH
    g. Min Run Time = 4 hours
    h. Max # of starts/day = 2 times
    i. Start-Up Costs = $6,000

2) Gas Prices
   a. Per Public Service internal forecasts
   b. Sensitivities provided by Public Service.

Description of modeling technique

The modeling technique applied in this study attempts to mimic the activities of generation schedulers and real time system operators. With variable generation (solar, wind, etc.) on the system, operators use a forecast of net load (load minus generation from renewable resources) to construct a plan for meeting customer demand for electric power. Fuel for gas-fired generating units is also purchased or "nominated" based on this plan. When the day arrives, both the load and net load will likely depart from the forecasts used to develop the unit commit plan. The consequence is that actual operations over the day will likely be suboptimal (i.e. not the lowest cost way to meet demand).

In reality, the forecasts (for both load and net load) are updated regularly throughout a day as is the unit commit plan. In the modeling for this study, however, the unit commit plan is constructed day-ahead and only once for each day. The actual net load for the day is than met using this commit plan that was developed the previous day. Inefficiencies arise because the actual net load differs from the day-ahead forecasted net load, forcing Couger to meet the actual net load with too many or too few units committed. If there are too few units, the automated "Unserved Energy" dispatch algorithm (described below) fills in the need. Larger differences between the forecasted and actual net load create bigger inefficiencies. These inefficiencies lead to excess system production costs which are the "integration costs" quantified in this study.

This modeling technique captures two sources of cost due to uncertainty: cost from uncertainty in the load forecast and cost from uncertainty in the solar generation forecast. Since the goal of this study is to determine solar integration costs, the costs due to uncertainty in the solar generation forecast must be separated from costs due to uncertainty in the load forecast.

The method to accomplish this separation compares the costs from two different Couger runs. First, Couger is run using the method detailed above, where both load and net load will differ from their forecasts (i.e., actual load and solar generation are different than the day-ahead forecasts). The costs of running the system for each day are totaled for the year. Next, Couger is run with only the load being uncertain – actual solar generation is modeled to match the day-ahead forecast of solar generation. Again, the costs for each day are totaled for the year. Subtracting the cost of the first run (with solar being uncertain) from the second leads to the total cost estimate of integrating solar on the Public Service system. Dividing this by the MWhs produced by the solar generation provides the cost per MWh. Also note that using this method removes the actual cost of the solar power from the calculations. The integration cost is strictly a measure of the inefficiencies in system operation introduced by the uncertainty added by solar generation.

It is important to note that the modeling technique applied in this study assumes that load and the available solar resource are uncorrelated and that the uncertainty in each of the two variables can be separated. However, to the extent that temperature drives load and the available solar resource drives temperature, this assumption is not strictly correct.

Description of automated "unserved energy" dispatch algorithm

In previous renewable integration studies, the Couger modeling of the Public Service system showed periods when generation was insufficient to serve customer loads (a.k.a., unserved energy). In order to eliminate these periods of unserved energy it was necessary to post-process each computer model run and manually add the costs associated with starting quickstart gas turbines. This was a very time consuming process, and more importantly, a human was performing the manual dispatch making more prone to error and inconsistency.

This study used an automated process to address unserved energy to reduce human error in the calculations. This process automatically runs 52 weekly Couger simulation cases with a post processing function to resolve any unserved energy and add those costs into the previously calculated production costs, gas consumption and unit hourly loading for gas units.

The parameters for calculating the added costs to eliminate unserved energy are as follows:

- Number of gas unit starts
- Hours of operation
- MWh generated

Other parameters used in these calculations are shown in Table 1 below.

Table 1: Parameters for costing unserved energy

Parameter	Value
Average Heat Rate	10.45 MMBtu/MWh
Cost of startup	$6,000
O&M for hours of operation	$126/hr
O&M for MWH of generation	$4.30/MWh
Gas cost	As specified in the inputs

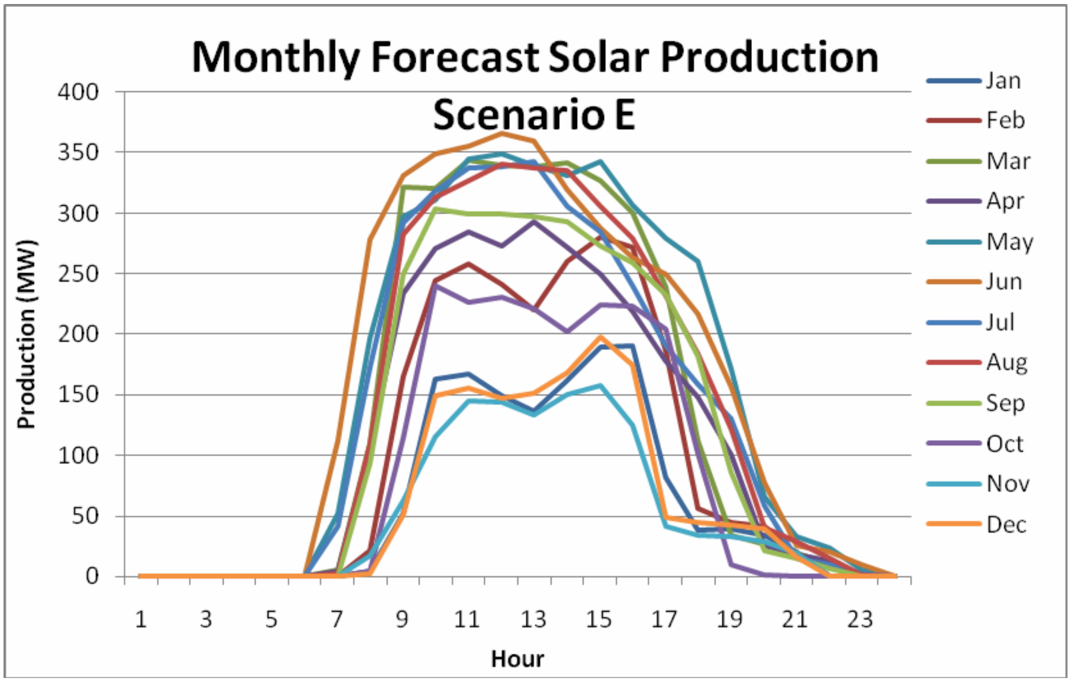
Unit starts were determined by analyzing the number of 130MW combustion turbines required to meet or eliminate the unserved energy. The algorithm requires that units be left on for at least 2 hours but does not incorporate minimum down times.

Day-Ahead Solar Forecasts

The modeling technique used for this study requires a day-ahead forecast of the solar insolation. However, neither EnerNex nor the Company could find any source for historical solar insolation forecasts so, for this study, solar forecast data was created from actual insolation data. For each hour the forecast is created by averaging the insolation for that hour for the entire month. For example, the solar forecast for any March day at 4pm is equal to the average insolation for 4pm every day in March. Figure 1 below shows an example of the forecast series developed for one of the scenarios.

As described later in the "Description of Scenarios" section of this report, each scenario included 200 MW of solar thermal generation with four hours of thermal storage. As can be seen in Figure 1, one effect of including this 200 MW facility in the production model is the generation of solar electricity after sunset in both summer and winter periods.

Figure 1: Graph of solar forecasts for Scenario E



Solar plant output from insolation data

Estimates of hourly solar generation patterns (a.k.a., energy production profiles) for various solar technologies were developed using the National Renewable Energy Laboratory's Solar Advisor Model ("SAM")[2] employing historical, hourly meteorological data (e.g., solar irradiance and air temperature) for the five examined locations from the Perez satellite data set.[3] In order to reduce the total number of cases examined but still capture the effects of the various photovoltaic (PV) cell technologies mounted in various orientations, the hourly energy production profiles employed in the study were generated from multiple SAM model runs and then averaged. Energy production profiles for the fixed PV cases were an average of profiles generated by the SAM model from polycrystalline silicon and thin-film CdTe modules with orientations facing due south and 20 degrees west of south; single-axis tracking PV cases were an average of profiles generated by the SAM model for polycrystalline silicon modules mounted in tracking systems in both horizontal and latitude-tilt configurations.

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[2] https://www.nrel.gov/analysis/sam/

[3] https://rpm.nrel.gov/

The five locations for which historical meteorological data were obtained were:

- Near Alamosa in the San Luis Valley,
- Public Service's Mosca substation in the San Luis Valley (25 km north of Alamosa),
- Public Service's San Luis Valley substation ("SLV") in the San Luis Valley (10 km west of Mosca),
- Near Pueblo,
- Near Denver.

Multiple locations in the San Luis Valley were selected in order to investigate the potential impacts of predicted hourly solar generation from facilities that would be expected to be highly, but not perfectly, correlated.[4]

[4] Perez data is reported to have a 10 km resolution. "Solar Resource Assessment"; Renne, George, Wilcox, Stoffel, Myers, and Heimiller. NREL/TP-581-42301, February 2008. http://www1.eere.energy.gov/solar/solar_america/pdfs/42301.pdf

DESCRIPTION OF SCENARIOS

The Company developed six scenarios to evaluate integration costs for solar generation on the Public Service system. The scenarios represent what the Company feels are credible future installations of solar generation on its electric generation system and still result in a manageable number of scenarios. Each scenario contains differing amounts of solar generation capacity in different locations within Colorado; each scenario, however, contained a minimum of 200 MW of solar generation from a solar thermal trough plant with four hours of thermal energy storage ("TES").[5] The Company made this assumption based on the Commission's decision in Docket No. 07A-447E that each portfolio presented to the Commission in Phase II of the Company's CRP should contain a minimum of 200 MW of solar thermal with thermal storage to the extent valid proposals are received (see Decision No. C08-0929). As stated above, the location of solar generation within each scenario is only relevant in that each location has a different level and pattern of solar insolation; transmission constraints or losses from the locations are not considered in the model. The six scenarios are detailed in Table 2 below.

For each scenario, a single 8,760 hourly solar generation profile was created by combining the output from each of the solar generation facilities in the scenario for each hour. Once the hourly generation profile is created, a monthly hourly solar forecast was created using the method described above.

Solar integration costs were estimated at three natural gas price levels. In the base gas case, a gas price forecast with an annual average of $9.83/MMBtu was assumed. In the sensitivity cases, low and high gas price forecasts with annual averages of $7.83/MMBtu and $11.83/MMBtu respectively were assumed.

[5] Public Service assumed four hours of thermal energy storage based on prior SAM model runs and a comparison with the Company's peak load hours.

Table 2: Table detailing the six scenarios (values in MW AC capacity)

Scenario A	Technology	Alamosa	SLV	Mosca	Pueblo	Denver
Total Scenario MW	trough 4TES *	200				
200	trough 0TES **					
	PV-Fixed					
	PV-1-axis					

Scenario B	Technology	Alamosa	SLV	Mosca	Pueblo	Denver
Total Scenario MW	trough 4TES	200				
400	trough 0TES		200			
	PV-Fixed					
	PV-1-axis					

Scenario C	Technology	Alamosa	SLV	Mosca	Pueblo	Denver
Total Scenario MW	trough 4TES	200				
600	trough 0TES		200	200		
	PV-Fixed					
	PV-1-axis					

Scenario D	Technology	Alamosa	SLV	Mosca	Pueblo	Denver
Total Scenario MW	trough 4TES	200				
800	trough 0TES		200	200		
	PV-Fixed				50	50
	PV-1-axis				50	50

Scenario E	Technology	Alamosa	SLV	Mosca	Pueblo	Denver
Total Scenario MW	trough 4TES	200				
400	trough 0TES					
	PV-Fixed	50			50	
	PV-1-axis	50			50	

Scenario F	Technology	Alamosa	SLV	Mosca	Pueblo	Denver
Total Scenario MW	trough 4TES	200				
600	trough 0TES				200	
	PV-Fixed	50				50
	PV-1-axis	50				50

* 4TES indicates a solar thermal trough facility with four hours (800 MWh) of thermal energy storage.

** 0TES indicates a solar thermal trough facility with no thermal energy storage

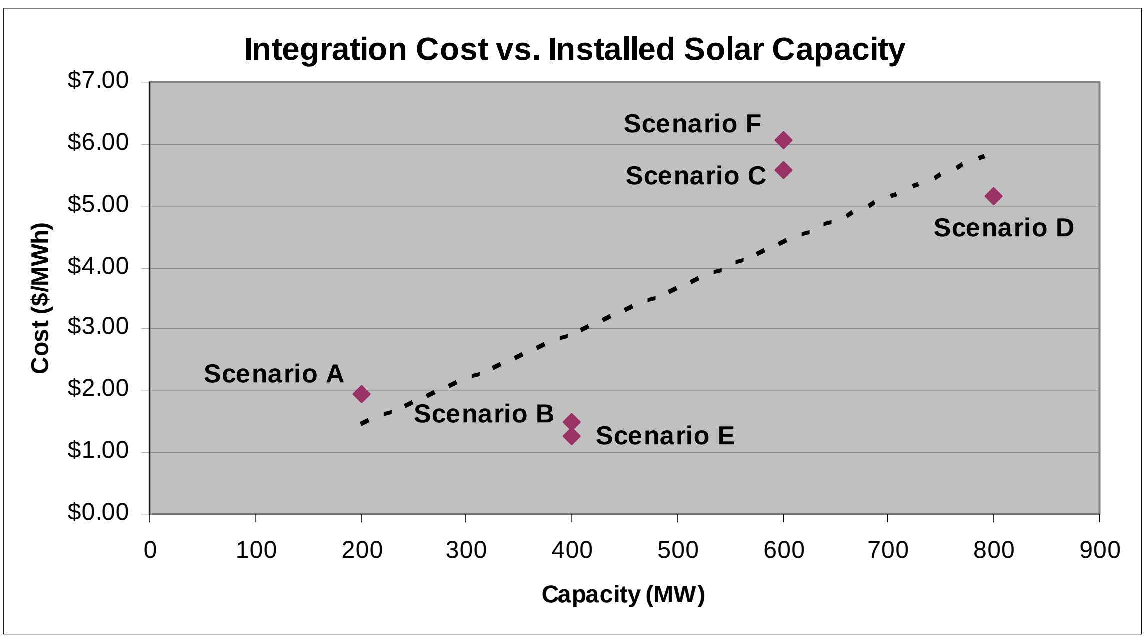
RESULTS

Table 3 shows the resulting integration cost estimates for all six of the scenarios studied. Figure 2 is a graph of these results. As previously noted, this study only quantifies the integration costs due to the production inefficiencies introduced by the uncertainty of solar generation. Additional costs resulting from regulation, gas supply, and increased O&M on Public Service's existing generating facilities was not quantified.

Table 3: Summary of Solar Integration Costs in $/MWh for Base Case Gas Assumption

Scenario	Solar Nameplate Capacity (MW)	Solar Energy (GWh)	Integration Cost ($/MWh of Solar Energy)
A	200	626	1.96
B	400	1044	1.49
E	400	948	1.25
C	600	1484	5.58
F	600	1531	6.06
D	800	1944	5.15

Figure 2: Graph of Solar Integration Costs with trend line



The most obvious trend of the Figure 2 data is increasing integration costs with increasing levels of solar generation. The trend line on the graph increases about $0.75 for each 100MW of additional solar capacity. Outside of the upward sloping trend, it is also noted that incremental additions over the base 200 MW case and above the 600 MW cases result in slight decreases in integration costs. Alternatively, the graph indicates that additions of solar up to roughly 400 MW come at cost of roughly $1.00 to $2.00/MWh whereas additions of solar from 400 to 800 MW come at a cost of roughly $5.00 to $6.00/MWh. The most likely explanation for the result may be that geographical diversity resulting from additional solar facilities may, up to a point, decrease the integration cost by reducing the overall variability of the aggregate solar generation output relative to the average generation values calculated to represent the day-ahead solar forecast. Based on the results of this study, it would be premature to conclude that geographic diversity has a particular $/MWh impact on integration costs without many more data points to support such a claim.

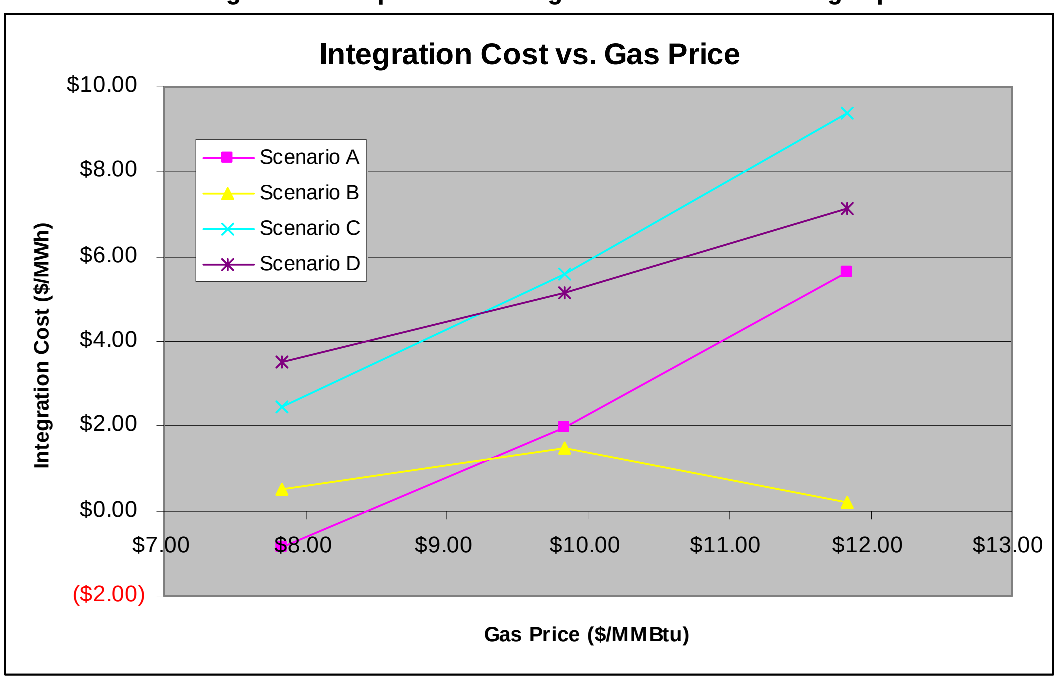
Effect of natural gas price on integration costs

Solar integration costs for four of the six scenarios were estimated at three different annual average natural gas prices: $7.83 (Low), $9.83 (Base), and $11.83/MMBtu (High). In three of the four scenarios, the analysis showed a clear correlation between gas price and solar integration cost as shown in Table 4 and Figure 3 below. For scenarios A, C, and D, the expected integration cost change by about $1.40/MWh for each $1.00/MMBtu change in average annual natural gas prices. The authors have no rationale explanation for the Scenario B high gas case at this time.

Table 4: Table of integration cost vs. gas price scenario

Generation Scenario	Solar Integration Cost ($/MWh)		
	Low Case	Base Case	High Case
A	($0.85)	$1.96	$5.62
B	$0.50	$1.49	$0.22
C	$2.47	$5.58	$9.38
D	$3.51	$5.15	$7.14

Figure 3: Graph of solar integration costs vs. natural gas prices



Although the slope of the curve for Scenario A is similar to that for Scenario C and D, the negative integration costs for Scenario A in the low gas price scenario ($7.83/MMBtu) is unexpected. Scenario A contains a single solar thermal plant with thermal energy storage whose hourly generation profile was generated by the dispatch logic contained within the SAM model. That is, the generation profile was set up to deliver energy during the highest value periods of the day based on system peak loads. Part of the results at the low gas price scenario for a thermal storage solar plant might thus be explained. However, more analysis would be necessary to determine the true reason for this result and to confirm if it is correct or just an artifact of the modeling methodology for low levels of solar generation.

The data in Figure 3 indicate that the effect of gas pricing on solar integration costs are, in general, linear; however, the authors would caution that these results not be extrapolated to other gas cost regimes. There are non-gas cost affects of solar integration (e.g., fixed start charges for combustion turbines as discussed above) that will be expected to have a significantly larger effect on the overall integration cost as gas costs decrease.

APPLICATION OF THE RESULTS

The $1.25 to $6.00/MWh integration cost estimated in this study for the base gas price scenario represents the integration cost of adding 200 to 800MW of solar generation on Public Service's system. For example, in the case of the first 200MW of solar on the system, the total integration cost estimate is ~$1.2M (= 626,000 MWh X $1.96/MWh). This integration cost represents the Company's best estimate of the "hidden" costs associated with the uncertain and hourly-variable nature of solar generation at this level of penetration. As such, this integration cost will be added to the explicit costs (capital + O&M, or contract price for PPAs) of solar facilities in the resource planning and selection process for portfolios containing 200 MW of solar capacity. Adding integration costs to solar generation in the planning process ensures that solar generation is compared on a level playing field with the other resource technologies and that all, currently quantifiable costs associated with solar generation are accounted for in the analysis.

In general, the levelized costs of large-scale solar energy (after accounting for federal tax subsidies) are currently on the order of $150 to $180/MWh. At the moderate penetration levels of large-scale solar facilities studied (10% penetration or lower), it is not expected that the relatively low levels of integration costs calculated here will have a significant impact on the selection of solar resources versus other generation resources available to the Company as part of its 2009 All-Source solicitation.

Summary and Discussion

Geographic Diversity and Integration Costs

Geographic diversity of solar plants appears to reduce the cost of integrating solar generation on the Public Service system. This conclusion should be viewed as preliminary since this study examined only a limited set of scenarios. However, this finding is consistent with results from prior wind integration studies: greater spatial diversity of generation leads to reduced variability in total production, which reduces integration costs.

Accurately quantifying the effect of geographic diversity on solar integration costs will be difficult and was not a major area of focus in this study. The Company does believe however that the reduction in integration cost with increased diversity makes intuitive sense and thus the general findings of this study in this regard are valid.

Effect of Gas Cost on Solar Integration Cost

The cost of natural gas had a direct impact on integration cost since flexible gas generation units are often used to maneuver and react to variations in output from the solar plants. Analysis of three different gas prices on three different solar integration scenarios indicate that the integration costs generally change about $1.40/MWh for each $1.00/MMBtu change in natural gas price.

Effect of Sub-Hourly Resource Variability on Solar Integration Cost

This study did not attempt to estimate the effect of sub-hourly generation variability of photovoltaic generation on solar integration costs. As previously stated, solar integration cost effects from sub-hourly, resource variability are likely to be driven by regulation time scale effects and not scheduling time scale affects as has been studied here. It is generally assumed that geographic diversity will be the primary solution to handling system operation issues from the extreme sub-hourly variability evident with photovoltaic generation. Currently, a lack of historical, sub-hourly solar resource data is hampering studies evaluating these issues.[4]