2021 Wind and Solar Integration Cost Study on the Public Service of Colorado System

Prepared by:
Xcel Energy Services, Inc
1800 Larimer St.
Denver CO 80202

March 31, 2021

Executive Summary

Wind and solar integration costs on the Public Service of Colorado (PSCo) system grow with increased penetration of renewable generation. The integration costs for solar energy grow at a rate of $0.72/MWh while wind energy increases at a rate of $2.84/MWh. Further, these costs change with natural gas price at a rate of $0.30/MWh and $0.50/MWh for every $1/MMBtu change in natural gas price. These costs reflect the growing forecast uncertainty in wind and solar generation enacted on a 2030 representation of the PSCo system. Combined, the integration costs can be escalated to reflect the natural gas price in any year of study.

Table 1 – Integration Costs and Rate of Change of Integration Costs

	Integration Cost ($/MWh)	Rate of Change ($/MWh per $/MMBtu)
Wind Generation	$2.84	$0.50
Solar Generation	$0.72	$0.30

This report details the above findings for 4 GW to 8 GW of total wind capacity and 2 GW to 5 GW of total solar capacity. The study methodology is the same as adopted for the 2016 solar integration cost study,[1] which in turn, is like methodologies adopted in integration cost studies prior. For example, the same method for deriving the solar and load forecast/actual pair data was utilized. Additionally, the non-wind and solar portfolio was based on a future (i.e., 2030) system rather than the present resource mix. Though, there are notable deviations from prior studies. The wind forecast/actual pair data was derived from operational data from a recent test year, rather than derived from NREL's Western Wind Resources Dataset. The solar integration costs were calculated with 5 GW of total wind capacity on the system and the wind integration costs were calculated with 3 GW of total solar capacity. The cases are shown in Table 2 below.

Three natural gas sensitivities were studied. The low, base, and high cases (Table 2) reflect the three natural gas forecasts adopted in the 2021 Energy Resource Plan in year 2030. The results from the base case provides the final integration costs as reported in Table 1, with the low, base, and high cases used to derive the rate of change of the integration costs.

The wind and solar integration costs are consistent with integration costs calculated in past studies. A constant rate was adopted across both the wind and solar penetration levels because it was both appropriate and simple.

[1] Xcel Energy Service Inc. "An Integrated Cost Study for Solar Generation Resources on the Public Service Company of Colorado System,", May 27, 2016.

Table 2 – Wind and Solar Integration Cost Run Matrix

Wind Integration Study *natural gas sensitivities $/MMBtu*

Case	Wind	Solar	Low	Base	High
1	4GW	3GW	$ 2.89	$ 3.46	$ 4.12
2	5GW				
3	6GW				
4	7GW				
5	8GW				

Solar Integration Study *natural gas sensitivities $/MMBtu*

Case	Wind	Solar	Low	Base	High
1	5GW	2GW	$ 2.89	$ 3.46	$ 4.12
2		3GW			
3		4GW			
4		5GW			

Introduction

Prior renewable integration cost studies have evaluated three components of integration costs: 1) impacts on electric system regulation, 2) impacts on electric system operation given uncertainty in wind and solar forecast generation versus actual generation, and 3) impacts on the Company's gas supply/storage system. Integration costs are narrowly defined herein as those costs derived from the inherent uncertainty of the wind and solar resources – previously called the System Operations Component of integration costs. Though, other integration costs relating to reserve requirements, gas system flexibility and supply, and firm capacity requirements are holistically being included in the Energy Resource Plan (ERP) modeling framework. As the ERP process has matured to endogenously consider numerous implications of a high renewable energy future such as increasing regulation reserves and firm fuel needs, costs due to uncertainty remain outside the modeling framework and are the primary focus of this study. As such, integration cost and uncertainty cost are used interchangeably.

Uncertainty costs derive from irreversible decisions due to imperfect information. In the power system, commitments are made in advance of real-time so as to ensure both reliable capacity and least-cost energy. These decisions require foresight. When information changes about the future, such as demand and renewable energy forecasts or unit availability, decisions to commit units may be irreversible, or the decision to forego commitment of less expensive facilities are now replaced with fewer, more expensive options. Often, even in the face of new information, the decisions made in the past are maintained, because the updated information is also uncertain (though a little less so) – and attempt to reverse a decision already made may leave one in an even greater bind in the future. Only at real-time are the costs of uncertainty realized; a culmination of prior decisions and indecisions, made in earnest, now are determined to be suboptimal relative to a modeled, perfect foresight, result. Uncertainty costs are added to resources that cause uncertainty. This appropriately costs this real-world burden that is otherwise ignored in the modeling framework.

The report details study methodology next, followed by results and conclusions.

Study Methodology

The study adopts the same methodology as the 2016 Solar Integration Cost study with some notable exceptions. The Company employed PLEXOS®, a production cost model licensed from Energy Exemplar, with a 2030 representation of the PSCo system. A day-ahead commitment of resources and power purchases and sales are made based on demand and renewable energy forecasts. These commitments are carried forward to real-time where actual demand and renewable energy production are balanced with a redispatch of on-line resources and purchase of real-time power. Additional units may be brought on-line to cover shortages, though possibly at great expense.

Case Development: Isolating Wind and Solar Integration Costs

Cases were developed with and without uncertainty for one resource type (wind or solar) layered on top of a base level of load and wind or solar uncertainty. For example, the wind integration study considered incremental uncertainty layered on top of load uncertainty and 3 GW of solar uncertainty, while the solar integration study considered incremental uncertain layered on top of load uncertainty and 5 GW of wind uncertainty (Table 3). This method was developed to isolate the impact of wind and solar over a reasonable base of uncertainty coming from other resources or loads.

Table 3 – Wind and Solar Integration Cost Run Matrix

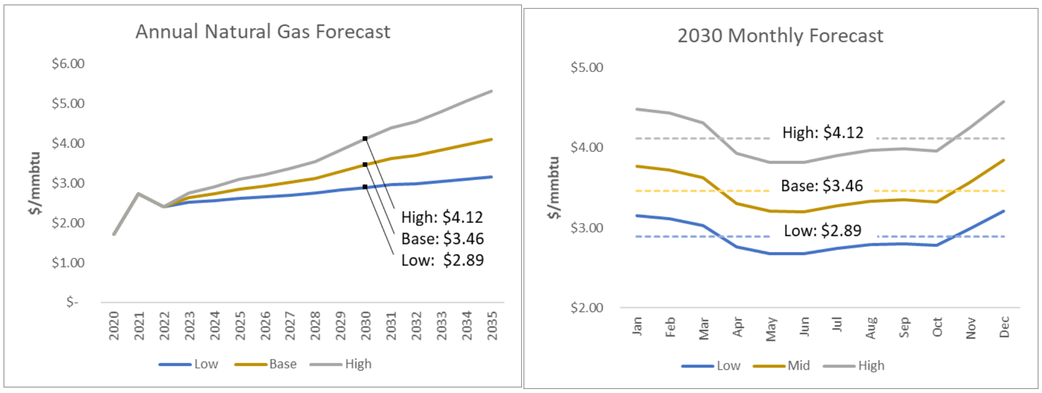
Wind Integration Study			*natural gas sensitivities $/MMBtu*		
Case	**Wind**	**Solar**	**Low**	**Base**	**High**
1	4GW	3GW	$ 2.89	$ 3.46	$ 4.12
2	5GW				
3	6GW				
4	7GW				
5	8GW				

Solar Integration Study			*natural gas sensitivities $/MMBtu*		
Case	**Wind**	**Solar**	**Low**	**Base**	**High**
1	5GW	2GW	$ 2.89	$ 3.46	$ 4.12
2		3GW			
3		4GW			
4		5GW			

Natural Gas Sensitivities

Three natural gas sensitivities were studied. The low, base, and high sensitivities (Table 3) reflect the three natural gas forecasts adopted in the 2021 Energy Resource Plan in year 2030. Figure 1 shows the ERP natural gas forecast with the 2030 low ($2.89/MMBtu), base ($3.46/MMBtu), and high ($4.12/MMBtu) values highlighted. In the second chart, the 2030 monthly values are shown; the simple average equaling the annual forecast. These forecast values were adopted for this study. The base case sensitivity provided the final integration cost value while the low, base, and high sensitivities were used to derive the rate of change of integration cost relative to natural gas prices.

Figure 1 – ERP Natural Gas Forecast and the 2030 Monthly Forecast



Forecast/Actual Pair Development

Modeling uncertainty requires the development of forecast data paired with realized, or actual, data. These datasets are referred as forecast/actual pair data. Forecast/actual pair data were developed for load, wind energy, and solar energy.

Load Data

Realized 2030 hourly load data was developed using the PLEXOS® model based on 2030 peak and energy forecasts and historic load shapes. Hourly forecast load errors for 2030 were assumed to be identical to actual hourly forecast load errors from 2011. That is, the required 2030 day-ahead hourly load value were calculated by combining the 2030 hourly load data and the 2011 actual hourly forecast load errors. 2011 data were used as they have low levels of net-metered solar generation embedded in the hourly load values than data from later years.

Wind Data

Forecast/actual pair data for wind energy are based on actual PSCo operations. The forecast/actual pair data are based on a historic test year from August 2019 to July 2020. The level of wind was constant over this period at 3125 MW of installed capacity. These forecast/actual pair data are scaled linearly to derive ever higher level of wind generation. There is an inherent trade-off in accepting and scaling known, real data in lieu of speculating on the future state and location of wind turbines. On one hand, actual data is superior to any synthesized data. On the other, limiting oneself to existing data eliminates consideration of future locations and turbine types. This study firmly sides with known, real data as a better basis for future uncertainty than to speculate on the turbine type, geographic extent, and weather at a new, undeveloped location that assume synthesized forecast/actual pair data in the process.

Solar Data

Conversely, there is not enough data to do the same for solar energy. Solar energy forecast/actual pairs are derived using NREL's Solar Power Data for Integration Studies[2] data; the same source as used in the

[2] Solar Power Data for Integration Studies - https://www.nrel.gov/grid/solar-power data.html

2016 solar integration study. Like in 2016, an exhaustive reconciliation of existing and future locations of solar was undertaken. The Solar Power Data includes geographic-specific forecast/actual data pairs for distributed (DPV) and utility-scale (UPV) solar generation in Colorado.

Distributed Solar Generation

Each of the ~60,000 existing distributed generators totaling 604 MW of installed capacity was mapped to the nearest distributed solar generation profile resulting in 30 DPV generation profiles. Distributed generation was assumed to grow proportionally according to the 2020 geographic share. Distributed generation is capped at 1500MW in the high penetration cases assuming growth in distributed generation can be accelerated to some extent but cannot grow at the accelerated pace needed to meet the higher penetrations studied. Table 4 shows the share of distributed solar generation by region in each of the future cases.

Table 4 – Distributed Solar Generation Share of Future Cases

	2020	Future Cases (based 2030)			
Case	n/a	2GW	3GW	4GW	5GW
DPV Share	*604*	*1000*	*1200*	*1500*	*1500*
NFR	547	905	1086	1357	1357
SFR	18	29	35	44	44
SE	0	0	0	0	0
SLV	0	0	0	0	0
WS	40	66	79	99	99
Other	0	0	0	0	0

*NFR – Northern Front Range, SFR – Southern Front Range, SE – Southeast, SLV – San Luis Valley, WS – Western Slope

Utility-Scale Solar Generation

Existing and planned utility-scale solar generators totaling 1124 MW were mapped to the nearest utility-scale solar generation profile resulting in 8 UPV generation profiles. The first tranche of utility-scale solar was assumed to be proportional to the existing and planned utility-scale solar generation installations. Thereafter, growth was assumed to be equal across five regions of Colorado. Table 5 shows the share of utility-scale solar generation in each of the future cases.

Table 5 – Utility-Scale Solar Generation Share of Future Cases

	2020	Future Cases (based 2030)			
Case	n/a	2GW	3GW	4GW	5GW
UPV Share	*1124*	*1000*	*1800*	*2500*	*3500*
NFR	122	109	257	397	597
SFR	670	596	805	945	1145
SE	200	178	335	475	675
SLV	132	117	267	407	607
WS	0	0	135	275	475
Other	0	0	0	0	0

*NFR – Northern Front Range, SFR – Southern Front Range, SE – Southeast, SLV – San Luis Valley, WS – Western Slope

Non-Wind and Solar Generation Portfolio

The non-wind and solar generation portfolio is assumed to be largely gas-fired generation with some battery and pumped hydro storage. Coal-fired plants are either retired (Hayden, Craig, Comanche 1, Comanche 2) or converted to natural gas (Pawnee, Comanche 3)[3]. The 2030 portfolio includes solar plus storage facilities, refurbishment of Cabin Creek, continued access to bilateral markets, and enough natural gas-fired combustion turbine capacity to replace expiring contracted or owned facilities.

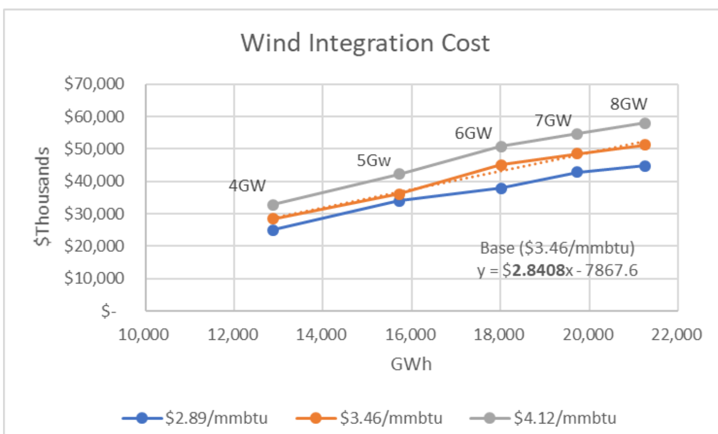
Study Results and Conclusions

Wind and solar integration costs are presented with the change in integration costs as a function of natural gas price.

Wind Integration Cost

Total wind integration costs for cases 4 GW to 8 GW, and three natural gas sensitivities, are shown in Figure 2. The existing wind integration cost is the rate at the 4 GW level (base case), or $2.21/MWh.[4] The incremental costs from 4 GW to 8 GW are consistently linearly with generation. The regression of the base case is shown with an incremental cost of $2.84/MWh. The difference between the high and low sensitivities relative to the base sensitivity results in an average cost differential of $0.49/MWh (high) and $0.51/MWh (low) for every $1/MMBtu difference in natural gas price. The average of these two differentials as taken as the final result of $0.50/MWh change in integration cost for every $1/MMBtu change in natural gas price.

Figure 2 – Wind Integration Costs



Solar Integration Cost Results

Total solar integration costs for cases 2 GW to 5 GW, and three natural gas sensitivities, are shown in Figure 3. The base and low sensitivity costs are consistently linearly with generation. The high sensitivity does not show a consistent nor intuitive result. The author suspects inconsistencies in the PLEXOS® model

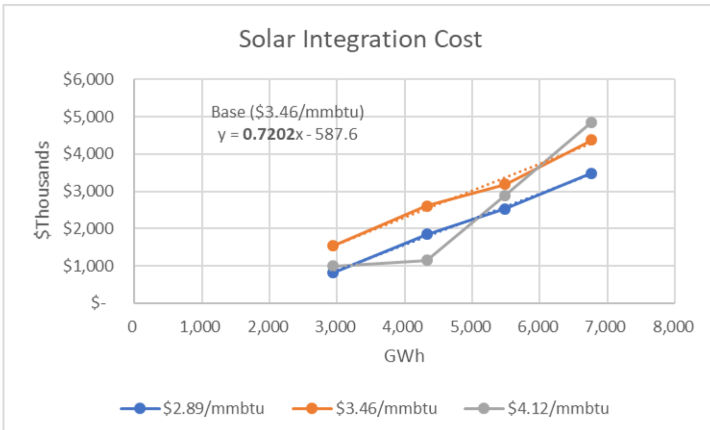
---

[3] Whether an existing coal-fired unit is modeled as a gas-fired unit or remains a coal-fired unit is not expected to affect the magnitude of the resulting integration costs as a single unit represents a small portion of the overall generation portfolio.

[4] This is the slope of the line between 0 GW and 4 GW wind with a gas cost of $3.46/MMBtu.

results for the high sensitivity studies. As such, the high sensitivity case is thrown out – as there is enough data between the low and base simulations to derive a consistent result. The existing solar integration cost is the rate at the 2 GW level (base case), or $0.52/MWh.[5] The regression of the base case is shown with an incremental cost of $0.72/MWh. The difference between the low sensitivity relative to the base sensitivity results in an average cost differential of $0.30/MWh for every $1/MMBtu difference in natural gas price.

Figure 3 – Solar Integration Costs



The result of the wind and solar integration cost study are shown in Table 6. Wind and solar energy have different integration costs. Wind energy has higher uncertainty costs and are more influenced by natural gas prices. Solar energy has much lower uncertainty costs – which is consistent with prior results.

Table 6 – Integration Costs and Rate of Change of Integration Costs ($2030)

	Integration Cost ($/MWh)	Rate of Change ($/MWh per $/MMBtu)
Wind Generation	$2.84	$0.50
Solar Generation	$0.72	$0.30

[5] This is the slope of the line between 0 GW and 2 GW solar with a gas cost of $3.46/MMBtu.