Solar PV integration cost variation due to array orientation and geographic location in the Electric Reliability Council of Texas

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Abstract

Adding large solar photovoltaic (PV) resources into an electric grid influences the flexibility characteristics of its net load profile. The dispatch of the existing generation fleet changes as it adjusts to accommodate the new net load. This study categorizes and defines these flexibility characteristics. It utilizes a unit commitment and dispatch (UC&D) model to simulate large solar generation assets with different geographic locations and orientations. The simulations show the sensitivity of the wholesale energy price, reserve market prices, total dispatch cost, fuel mix, emissions, and water use to changes in net load flexibility requirements. The results show that generating 22,500 GWh of solar energy in a 2011 simulation of the Electric Reliability Council of Texas (ERCOT) reduces total dispatch cost by approximately \$900 Million (a 10.3% decrease) while increasing ancillary services costs by approximately \$10 Million (a 3% increase). The results also show that PV reduces water consumption and water withdrawals as well as CO₂, NO_x, and SO_x emissions. It also reduces peak load by 4% but increases net load volatility by 40-79% and ramping by 11-33%. In addition, west-located, west-oriented solar resources reduce total dispatch cost more than the other simulated solar scenarios. The west-located, west-oriented solar simulation required greater system flexibility, but utilized more low-cost generators and

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fewer high-cost generators for energy production than other simulated scenarios. These results suggest that the mix of energy provided by different generation technologies influences the dispatch cost more than the net load flexibility requirements.

Keywords:

Solar PV integration, Electricity dispatch costs, ERCOT, Unit commitment & dispatch modeling, Grid Flexibility

1. Introduction

Solar photovoltaic (PV) electricity assets have historically generated negligible amounts of energy in electric grids around the world, for which hydroelectric and thermal power plants account for the majority of electricity generation [1]. Yet, the small carbon profile and low marginal price of solar electricity are of interest to planners because they can reduce wholesale energy costs while avoiding emissions. As solar installation costs continue to fall, installed utility-scale solar capacity is expected to grow dramatically. As grids incorporate more solar capacity, it is prudent to assess the trade-offs of integrating solar generation into an electric grid. Independent System Operators (ISOs) are concerned with accommodating over-generation and increased ramping requirements as illustrated by the California ISO experience with the so called “duck curve” (where low net loads are followed by steep ramp rates) [2] and Germany’s experience with widespread negative wholesale prices [3]. These experiences illustrate how existing electricity markets might struggle to provide the operational flexibility required for the successful integration of solar generation. Increased generator flexibility requirements have been oft-discussed [4–6] and some strategies for mitigating them have been suggested, such as installing more storage or west-facing solar assets [7], or by increasing the flexibility of the load via dispatchable loads [8] such as district heating systems [9] or electric vehicles [10, 11]. Yet, flexibility requirements represent only a portion of the total integration costs. The uncertainty of solar forecasts and the underutilization of existing thermal generators also contribute to integration costs [12].

Because decisions about long-lived capital assets loom and solar generation is growing, there is a need to quantify the integration costs and market benefits of large-scale solar generation. This publication contributes to the growing area of research on the grid-integration of renewable energy by

providing a holistic study of how generator dispatch, system flexibility requirements, and market dispatch costs are influenced by the orientation and geographic location of solar generation assets. The information in this study can encourage utilities, grid operators, and other entities involved with influencing the development of the electric grid to develop renewable energy portfolios, tax incentives, and investment plans that consider the comprehensive costs of integrating solar into the grid.

2. Background

Existing research about integration costs shows that the value of solar capacity decreases as more of it is installed [13, 14]. Research also shows that larger amounts of renewable energy generation require greater flexibility from dispatchable generation assets [5, 14] while also reducing their utilization and potentially having little impact on the overall peak demand [15]. Other studies use duration curves and merit order analyses to show how renewable energy resources affect the spot price of electricity [16, 17]. Because solar production varies based on astronomical and meteorological conditions, gaining a deeper understanding of the impact of renewable energy sources requires considering the time of day and season during which it is produced [18, 19]. Historical data on renewable energy generation can be compared with historical prices to gain a more temporal understanding of the impact of renewable energy on wholesale prices [20, 21]. However, the impact of large solar resources, or aggregations of many smaller units, can be better understood by simulating their participation in the electricity market.

Electricity market operators decide how to dispatch their generation assets by using unit commitment and dispatch (UC&D) algorithms that optimize the dispatch to produce the lowest total dispatch cost [22]. UC&D models can be used to estimate the value of renewable energy resources in electricity markets [23, 24], observe how renewable generation influences the utilization of power plants [25, 6, 26], test how different market structures can facilitate the integration of renewable energy sources into the electric grid [27], and to assess transmission investments necessary for meeting renewable energy goals [28].

The generation profile of a solar array is largely dependent on its geographic location and azimuth orientation. Studies show that an owner can maximize the value of a small solar array by optimizing its orientation and tilt according to historical prices, peak demand timing, and pricing structures

rather than simply maximizing its annual energy output [19, 29–31]. However, since large installations of solar generation influence wholesale prices, generator dispatch, and net demand timing, these studies provide limited insight regarding the optimal orientation for large penetrations of solar generation in the grid.

Building on the existing literature above, which communicates many individual, generalized aspects about integrating solar generation into the grid, this study undertakes a comprehensive assessment of how large amounts of solar generation might influence the system-wide flexibility requirements, hourly generation fleet dispatch, and resulting dispatch costs and emissions in an actual electricity market. This study aims to extend solar integration cost research by simulating the hourly generator dispatch of the Electric Reliability Council of Texas (ERCOT, the system operator of the electric grid covering about 85% of Texas’ population) under different solar penetration scenarios. The simulation results provide novel information about how solar integration costs change depending on the daily and seasonal timing of the solar generation profile.

These simulation results are calculated by an advanced and calibrated UC&D model of ERCOT as described in the Methods section of this study. ERCOT serves as a useful testbed because it is an isolated grid with a diverse fuel mix, a large capacity of wind generation, strong potential for solar growth, and a competitive wholesale energy market [22]. Its load is driven by summer cooling with approximately half of its peak summer demand coming from residential air conditioning [32]. It is anticipated that quantifying the integration costs and market benefits of solar generation in ERCOT will provide useful information for other electricity markets as well, especially markets with large summer cooling loads, as they develop capacity expansion plans for the future.

3. Methods

This study utilizes a UC&D model of the ERCOT electricity market developed by Garrison, et al. [22]. The model is built in the PLEXOS Integrated Energy Model (PLEXOS) software. The model includes each generator in the ERCOT grid, and assigns them unique variable marginal heat rates, maximum capacities, and performance parameters based on their fuel type and technology. It utilizes hourly load, wind generation, and solar generation profiles, along with other system parameters to calculate the hourly

dispatch of each generator, hourly prices, the total dispatch cost, and other market information. These calculations are performed by a mixed-integer linear program that includes the operating costs of each generator in its objective function. The total dispatch cost includes generator start-up costs and the cost of purchasing reserve capacity from the generators, but its largest portion is calculated by multiplying the hourly energy price (\$/MWh) by the total amount of generation needed in each hour. The energy price is determined by the marginal operating cost of the most expensive dispatched generator. With this calculation in mind, the program chooses the hourly dispatch for each generator that minimizes the total daily dispatch cost of the ERCOT system, provides enough hourly generation and reserves to meet the hourly demand, and respects ramping, capacity, and other generator operational constraints. This optimization is performed for each day of the year producing an hourly dispatch schedule for all 8,760 hours of the year.

The ERCOT UC&D model has been calibrated to historical 2011 data for wholesale prices, ancillary service prices, and fuel use, and can accurately reproduce the historical 2011 ERCOT market [22]. While the model can produce accurate results, its current version has several limitations. It does not include transmission constraints treating ERCOT as a single node, assumes marginal cost bidding behavior by the generators, and uses perfect load and renewable electricity generation forecasts. The primary impact of these limitations is a poor representation of non-marginal bidding behavior by the generators, which leads to an inability to reproduce price spikes under scarcity conditions. Additional details on the development of this ERCOT UC&D model can be found in Garrison’s doctoral dissertation [22].

The primary analysis in this study involves the comparison of different solar arrays in Texas based on their geographic location and orientation. Rather than compare dozens of scenarios with different locations and orientations around the state of Texas, this study limits its scope to observing the extremes of possible solar output profiles. An east-facing (90 degree) solar array installed in east Texas (Longview, Texas) and a west-facing (270 degree) solar array installed in west Texas (El Paso, Texas) represent the range of solar generation possibilities in ERCOT. Though El Paso is not connected to the ERCOT grid, it is the closest weather data location for approximating far west ERCOT PV output in the PV generation calculator utilized in this study. Figure 1 illustrates the normalized generation profiles for a maximum-output summer day for each scenario showing that their peak production times occur approximately 3 hours apart. The generation

Figure 1: The normalized generation curves for the three different solar scenarios show the typical variation in the timing of their electricity generation during the course of a summer day. The East and West scenarios peak approximately three hours apart from each other and represent the bounds of solar generation timing in ERCOT [33].

profile of any other configuration of solar assets in ERCOT will fall within the timing bounded by these two profiles. A south-facing (180 degree) solar array installed in central Texas (Abilene, Texas) was also added to provide additional insight to the results. All times are reported in Central Standard Time. The three solar scenarios will be referred to as “East”, “South”, and “West” in this report as indicated in the map of ERCOT shown in Figure 2.

The hourly output data for the East, South, and West solar generation curves were created by utilizing the PVWatts Calculator developed by the National Renewable Energy Laboratory (NREL) [33]. This calculator uses solar insolation information from typical meteorological year (TMY) data to estimate the hourly electricity generation of a solar array based on its location, orientation, and other input criteria. Each array is tilted at 20 degrees above horizontal, a common tilt used to favor summer-time electricity generation, and the default value used by the PVWatts Calculator. Default PVWatts data were also used for the array type, system loss, DC to AC size ratio, inverter efficiency, and ground cover ratio values. The criteria chosen for the East, South, and West scenarios are summarized in Table 1.

Rather than assigning the same installed capacity to each of the solar arrays for the different scenarios, each array’s capacity was sized to generate

Figure 2: This figure shows the State of Texas with the ERCOT boundary shaded in blue. The cities associated with the East, South, and West scenarios are indicated.

22,500 GWh of annual energy, about 6.8% of annual generation in 2011. While specifying an identical capacity for each of the arrays would provide a more straightforward comparison of their net load profiles and flexibility

Table 1: Input data used to generate the solar PV hourly generation curves for the different scenarios. All parameters were set to the default values except the weather data set and array azimuth.

Scenario	Weather Data Set	Array Azimuth (deg)	Array Tilt (deg)	Array Type	System Loss	DC to AC Size Ratio	Inverter Efficiency	Ground Cover Ratio
East	TMY3 Longview Gregg County Airport, TX	90	20	fixed	14%	1.1	96%	0.4
South	TMY3 Abilene Regional Airport, TX	180	20	fixed	14%	1.1	96%	0.4
West	TMY3 El Paso International Airport, TX	270	20	fixed	14%	1.1	96%	0.4

Figure 3: The monthly energy output of the different arrays is influenced by seasonal shifts in weather and the sun's path through the sky as well as the installed capacity of the arrays.

requirements (see sections 4.2 and 4.3), the scenarios would produce different amounts of annual solar energy - an aspect that would greatly complicate the comparison of their dispatch costs, generator dispatch, and emissions calculations (see sections 4.1, 4.4, and 4.5). Sizing the arrays to produce the same annual solar energy allows their dispatch and emissions to be easily compared while still allowing a reasonable opportunity to compare their net load profiles and flexibility requirements. Based on trial-and-error model simulations, 22,500 GWh of energy generation was selected because it is large enough to impact the market, but small enough to eliminate solar curtailment and avoid low net loads, which can be difficult for the model to optimize. The East, South, and West arrays were sized at 18.3 GW, 14.2 GW, and 15.0 GW, respectively to match this generation level. The monthly energy production for each solar array is presented in Figure 3. The shapes of these energy generation profiles are influenced by seasonal shifts in weather and the sun's path through the sky as well as the installed capacity of the arrays. The one-year hourly generation data for each of these scenarios was incorporated into the ERCOT UC&D model with historical 2011 hourly load and 2011 hourly wind generation data. All 8,760 hours of the year are simulated for each solar scenario and for a base case that does not include solar.

4. Results and Discussion

Solar arrays with different locations and orientations will require different capacities to generate the same amount of annual energy. While the South and West array capacities are within 5% of each other, the East array has over 20% more capacity than either of the other scenarios due to orientation and different meteorological conditions that yield less overall solar insolation [34]. A system with greater capacity can produce greater instantaneous generation and ramping. This distinction should be kept in mind when analyzing the results. Additionally, while this UC&D model can accurately simulate the ERCOT day-ahead market, it does not completely predict all of the market behavior that affects prices and dispatch in the real-time market, such as extremely high prices caused by competitive bidding during times of high grid stress. The results presented in this study are not meant to make detailed predictions but to illustrate big-picture trends and intuitions. The results show how total dispatch cost, net load reduction, net load flexibility requirements, fuel use, and emissions vary between the different scenarios. Most of the results are summarized in Table 2.

4.1. Prices and Total Dispatch Cost

The wholesale energy price is the compensation (\$/MWh) paid to all generators for the amount of energy they produced for the wholesale electricity market during a given time frame. Table 2 shows that solar generation reduces the average energy price over the entire year. When comparing the solar scenarios, the East scenario has the lowest average annual energy price and the South scenario has the highest. The simulation results also show that, when compared with the No Solar scenario, solar generation reduces energy prices more in the summer than in the winter. It also increases price volatility in the winter and reduces price volatility in summer as shown in Figure 4.

In addition to purchasing energy generation, electricity markets also purchase ancillary services that provide reserve generation capacity and grid stability features. The 2011 ERCOT model developed for this work uses four types of ancillary services. “Regulation Up” and “Regulation Down” services require on-line generators to raise or lower their generation within five minutes. “Responsive” services require on-line generators to raise their generation within ten minutes. “Non-Spinning” services require off-line generators to come online and provide generation within thirty minutes. New

Table 2: The results for each of the four 8,760-hour UC&D simulations of the ERCOT electricity market are shown below. The information is categorized into smaller tables corresponding to each of the “Results & Discussion” sub-sections in this report.

Solar Data	Array Size	(GW Capacity)	East	South	West	No Solar
	Annual Total Solar Generation	(GWh)	22,500	22,500	22,500	-
		(% of Annual Energy Demand)	6.8%	6.8%	6.8%	-
4.1 Prices & Total Dispatch Cost	Annual Total Dispatch Cost	(\$ Billion)	7.98	7.94	7.90	8.81
		(% reduction vs. No Solar)	9.4%	9.9%	10.3%	-
		Ancillary Services Cost (\$ Billion)	0.308	0.306	0.306	0.297
	Average Yearly Prices	Energy (\$/MWh)	33.73	33.92	33.80	35.53
		Regulation Up (\$/MWh)	10.55	10.51	10.59	10.23
		Regulation Down (\$/MWh)	6.85	6.66	6.28	5.09
		Responsive (\$/MWh)	12.94	12.96	13.03	12.88
4.2 Net Load Red.	Maximum Net Load	(GW)	62.9	62.6	63.2	65.8
		(Hours)	50	28	12	204
	Minimum Net Load	(GW)	9.1	11.4	12.3	15.4
		(Hours)	61	36	13	0
4.3 Net Load Flexibility Req.	Ramp Down Requirement	Average(GW/hr)	4.4	3.9	3.9	3.5
		Std. Dev. (GW/hr)	1.3	1.1	1.0	1.1
	Ramp Up Requirement	Average(GW/hr)	4.5	4.1	4.6	3.6
		Std. Dev. (GW/hr)	1.5	1.5	1.5	1.3
	Ramp Up Factor Requirement	Average(GW/hr per GW)	0.16	0.14	0.16	0.12
		Std. Dev. (GW/hr per GW)	0.06	0.05	0.07	0.03
		Year Max. (GW/hr per GW)	0.51	0.42	0.47	0.22
		Year # Hrs Ramp Fact.> 0.35	5	2	5	0
	Volatility Requirement	Average(GW/(hr*day))	36.1	28.3	32.6	20.2
		Std. Dev. (GW/(hr*day))	10.5	8.7	9.4	4.0
4.4 Generation by Generator Type	Coal	(GWh)	123,800	123,500	124,100	128,700
		(% Reduction vs. No Solar)	3.8%	4.0%	3.6%	-
	Hydroelectricity	(GWh)	815	815	815	820
		(% Reduction vs. No Solar)	0.6%	0.6%	0.6%	-
	Nat. Gas Boiler	(GWh)	3,580	3,050	2,350	5,310
		(% Reduction vs. No Solar)	32.6%	42.6%	55.7%	-
	Nat. Gas Combined Cycle	(GWh)	106,300	106,800	107,300	121,700
		(% Reduction vs. No Solar)	12.7%	12.2%	11.8%	-
	Nat. Gas Internal Combustion	(GWh)	700	700	680	740
		(% Reduction vs. No Solar)	5%	5%	8%	-
	Nuclear	(GWh)	40,000	40,000	40,000	40,000
		(% Reduction vs. No Solar)	0%	0%	0%	-
4.5 Emissions & Water Use	Open Cycle Gas Turbine	(GWh)	3,630	3,700	3,440	3,920
		(% Reduction vs. No Solar)	7.4%	5.6%	12.2%	-
	Wind	(GWh)	31,000	31,000	31,000	31,000
		(% Reduction vs. No Solar)	0%	0%	0%	-
	CO ₂	(million tons)	193	192	192	207
		(% Reduction vs. No Solar)	6.8%	7.2%	7.2%	-
	NO _x	(thousand tons)	99.6	99.1	98.9	105.5
		(% Reduction vs. No Solar)	5.6%	6.1%	6.3%	-
	SO _x	(thousand tons)	321	319	321	336
		(% Reduction vs. No Solar)	4.5%	5.1%	4.5%	-
	Water Consumption	(billion gallons)	106	106	106	112
		(% Reduction vs. No Solar)	5.4%	5.4%	5.4%	-
	Water Withdrawals	(billion gallons)	8,440	8,420	8,410	8,720
		(% Reduction vs. No Solar)	3.2%	3.4%	3.6%	-

ancillary service markets being designed by ERCOT [35] will affect future iterations of the model used for this study, but the model does not currently account for these pending market updates.

While prices communicate some information about how solar generation affects the electricity market, total dispatch cost (the cost of providing energy and ancillary services for the electric grid) is a more useful metric for judging the overall impact of solar generation. Total dispatch cost amounted to \$8.81 Billion for the No Solar scenario. This amount was reduced in the East, South, and West scenarios by 9.4%, 9.9%, and 10.3%, respectively - a reduction of approximately \$900 Million. A 10% reduction in total dispatch cost resulting from solar energy producing only 6.8% of total energy demand indicates a high value for the electricity generated by solar. Figure 5 shows how each solar scenario reduces the monthly total dispatch cost throughout the year. When comparing the solar scenarios with each other, the East scenario reduces total dispatch costs most in July and August, the South scenario most from October through February, and the West scenario most for March through June and for September. Many factors influence the difference in total dispatch costs between the solar scenarios, but there is a strong correlation between the dispatch costs and the seasonal solar output of the arrays shown in Figure 3. Noticeably, the East array only reduces the July and August dispatch costs slightly compared to the other scenarios, though it produces significantly more energy during those months. This result speaks to the lower quality of the East array's production as its peak power output occurs a few hours before peak demand and it introduces higher flexibility requirements as discussed in Section 4.3.

While solar generation reduces total dispatch cost, it increases the cost of procuring ancillary services. As seen in Table 2, solar generation causes the average yearly ancillary services prices to increase by 2.7-3.5% for Regulation Up, 23-35% for Regulation Down, and 1% or less for the other ancillary services. The West array increases Regulation Up prices and the East array increases Regulation Down prices more than the other scenario, a result that correlates with the Ramp Up and Ramp Down Requirements discussed in Section 4.3, where a system with greater Ramp Down Requirements might be expected to pay more for Regulation Down services. Ancillary services cost, the annual amount paid to generators for procuring ancillary services, amounted to \$297 Million for the No Solar scenario. This amount increased by approximately 3.1%, or \$10 Million, for the solar scenarios. Since this cost accounts for only 3.4-3.9% of the total dispatch cost, a 3.1% increase in

Figure 4: The monthly price averages and standard deviations change depending on the solar scenario. Solar tends to increase monthly price standard deviation in the winter and decrease it in the summer. It also decreases energy prices more in the summer than in the winter.

ancillary services cost has a small effect on the market as a whole. The \$900 Million reduction in total dispatch cost created by solar generation is much more substantial than the \$10 Million increase in ancillary services cost.

4.2. Net Load Reduction

Since wind and solar electricity resources have zero marginal costs, they are usually dispatched first (unless there is curtailment because of transmission congestion or oversupply), and dispatchable generation resources meet the remaining demand. This tendency is captured in the net load, where net load is equal to the total load minus the electricity generated by solar and wind resources. The peak-period and off-peak net loads encountered during the UC&D simulation are useful tools for comparing the different solar scenarios. Smaller peak-period net loads indicate that fewer dispatchable resources are needed to meet demand and suggest that peak-load generation assets might be dispatched less often. Smaller off-peak net loads indicate that more dispatchable resources must be turned off or operate at their minimum capacities. This situation can increase dispatch costs by incurring more generator start-up costs and causing generators to operate at less-efficient capacities. Wind and solar resources can also be curtailed to balance low net loads, though this study uses a no-curtailment constraint.

Figure 5: Each solar scenario reduces the monthly total dispatch cost when compared to the No Solar scenario. Summer months see more savings due to greater solar output and the alignment of solar generation with peak demand.

The net loads for each scenario are illustrated in the Figure 6 duration curve. This figure indicates that the West array will generally reduce the highest net load values more than the South or East arrays. These results suggest that electricity generation from the West array is more aligned with peak summer demand than the other scenarios and will require less energy generation from peak-load generators. However, all three scenarios have similar maximum net loads for the year requiring similar dispatchable generation capacity to meet maximum net demand. The figure also indicates that the East array will create the lowest net loads of the three arrays. These results suggest that electricity generation from the East array is more aligned with minimum shoulder-season demand than the other scenarios and will force base-load generators to shut-down or operate at minimum capacity more often.

4.3. Net Load Flexibility Requirements

The hourly profile of the net load indicates the load and ramp rates that must be met by dispatchable resources to accommodate the full solar and wind capacity. Increased volatility and ramping in the net load curve imply the need for more flexible generation resources or renewable energy curtailment. The flexibility requirements of the different scenarios can be compared by calculating a number of net load ramping characteristics.

Figure 6: The net load duration curve with insets magnifying the highest and lowest net load values shows the number of hours per year experienced at different net loads by each scenario. During the highest net load hours of the year, the West net load is generally smaller than the South net load which is smaller than the East net load. However, all three solar scenarios have similar maximum net loads for the year. During the lowest net load hours of the year, the West net load is larger than the South net load which is larger than the East net load.

Ramp rates are calculated by subtracting the previous hour's net load from the current hour's net load as shown in equation 1, where t is time in hours. "Average Ramp Down Requirements" are calculated by taking the steepest negative ramp rate during each day of the year and averaging these 365 ramp rates together. Similarly, "Average Ramp Up Requirements" are derived by averaging the largest positive ramp rates for each day of the year.

$$RampRate(t) = NetLoad(t) - NetLoad(t - 1) \quad (1)$$

"Ramp Factors" are calculated by dividing the 1-hour net load ramp rate by the previous hour's net load as shown in equation 2. A ramp factor of 0.50 means that the generation fleet must increase its generation output by 50% over the next hour. "Average Ramp Up Factor Requirements" are calculated by taking the maximum ramp factor during each day of the year and averaging these 365 ramp factors together. While ramp requirements communicate the megawatt-per-hour changes needed from the generation fleet, ramp up factor requirements anticipate the difficulties of quickly ramping up a generator fleet with limited on-line capacity.

$$RampFactor(t) = \frac{RampRate(t)}{NetLoad(t - 1)} \quad (2)$$

Finally, "Volatility" is used to observe the effects of intermittent solar output on the net load. First, "Ramp Acceleration" is calculated by subtracting the previous hour's ramp rate from the current hour's ramp rate and taking the absolute value of the result as shown in equation 3. Then, the "Daily Volatility" is calculated by summing the 24 ramp acceleration values for each hour in a day. "Average Volatility Requirements" are calculated by taking the volatility for each day of the year and averaging these 365 volatilities together.

$$RampAcceleration(t) = abs(RampRate(t) - RampRate(t - 1)) \quad (3)$$

Average ramp down and ramp up requirements are 11-28% greater, average ramp up factor requirements are 17-33% greater, and average volatility requirements are 40-79% greater for the solar scenarios than for the No Solar base case. The maximum annual ramp up factors are 91-132% greater for the solar scenarios than for the No Solar base case. Though these maximum values indicate extreme ramping situations that might occur only once per

year, the generation fleet must be capable of providing that flexibility to meet reliability expectations.

The results in Table 2 show that the East scenario has the greatest average ramp down and volatility requirements, the South scenario has the lowest requirements in all of the categories, and the West scenario has the greatest average maximum ramp up requirements. The scenarios can be listed in order of greatest flexibility requirements as East > West > South.

4.4. Generation by Generator Type

The ERCOT UC&D model utilized in this study tracks the hourly energy production of each generator in the fleet. Categorizing these generators based on their fuel type and technology reveals which types of generators will be dispatched more or less often with greater solar penetration. Table 2 shows the total energy (GWh) produced by each generator type for each of the four scenarios. Among the solar scenarios, energy generation from natural gas boilers was greatly reduced, and energy generation from natural gas combined cycle (NGCC) resources was reduced by a greater percentage than for open cycle gas turbines (OCGT) even though OCGT resources are more expensive to operate. Figure 7 shows the 24-hour generator mix for July 25th. It illustrates how the net load and generation fuel mix changes for each scenario during a day of maximum solar output in the summer and shows how solar can reduce maximum net load in the summer displacing the most expensive generators in the bid stack.

In addition to reducing the maximum net load, solar generation also changes the way generators are dispatched by utilizing them to handle the increased net load ramp rates and volatility. Figure 8 shows the 24-hour generator mix for March 5th. It illustrates how the net load and generation fuel mix changes for each scenario during a day of maximum solar output in the spring and shows how solar can create low net loads followed by steep ramp rates requiring dispatchable generation to operate more flexibly. Figure 9 charts the average hourly dispatch for NGCC (slow-ramping, mid-load) and OCGT (fast-ramping, peak-load) generators during the year. While fast-ramping generators (e.g. OCGT) help compensate for PV generation by ramping up in the evening, slow-ramping, mid-load generators (e.g. NGCC) play an important role by absorbing much of the mid-day solar generation as well as providing ramping support. In most markets, where mid-load capacity greatly exceeds fast-ramping capacity, the mid-load generation will

Figure 7: These charts show each scenario's hourly fuel mix during a typical summer day. The net load is represented by the bottom of the wind generation area. The "duck curve" is not as apparent during the summer season when solar generation is aligned with peak demand.

compensate for large, bulk changes to the net load, while fast-ramping generation will act to increase short-term ramping capabilities.

While utilization of the least expensive generation resources (hydroelectricity, nuclear, wind) is almost unchanged, the dispatch of slow-ramping generators is reduced by percentages roughly corresponding to their marginal cost (i.e. natural gas boilers, having greater marginal costs than coal, are dispatched less than coal overall). Alternatively, fast ramping, expensive, peak-load generators such as open cycle gas turbines are also displaced during peak solar generation hours but recover some of their utilization by providing ramping support in the evening.

4.5. Emissions & Water Use

Since solar generation displaces existing thermal generation resources without producing emissions or using cooling water, it has a significant impact on the amount of emissions produced and water utilized in the electricity market. The production of CO₂, NO_x, and SO_x emissions as well as the withdrawal and consumption of water are calculated in the model. Water withdrawals denote the total amount of water entering the cooling system of a power plant (much of which is returned to a water body) and water consumption denotes the amount of water lost to evaporation during the cooling process.

The results in Table 2 show that increased solar generation leads to reductions in emissions and water. The West scenario reduces NO_x emissions and water withdrawals more than the other scenarios while the South Scenario reduces SO_x emissions more. The East scenario has a lower impact on CO₂ emissions, NO_x emissions, and water withdrawals than the other scenarios.

5. Conclusions

While the four scenarios produce different results, they all support some generalizations about solar penetration in ERCOT. First, 22,500 GWh of solar generation reduces the total dispatch cost in the ERCOT market by approximately \$900 Million per year. The cost reduction percentages in all three scenarios (9.4-10.3%) exceed the percentage of total energy provided by the arrays (6.8%), which is a non-obvious result. This result occurs partly because the energy that is being displaced by low-cost solar tends to come from higher-than-average cost generators rather than from lower-than-average cost generators. The solar arrays in this study also increased ancillary services

Figure 8: These charts show each scenario's hourly fuel mix during a typical spring day. The net load is represented by the bottom of the wind generation area. The "duck curve" manifests itself in ERCOT during the shoulder seasons when there is abundant spare capacity. ISOs have expressed concern about accommodating the steep evening ramp rates shown here.

Figure 9: The top two charts show the hourly output of natural gas combined cycle (NGCC) and open cycle gas turbine (OCGT) generators averaged over the year for each scenario. The bottom two charts show the annual average hourly dispatch of a solar scenario minus the annual average hourly dispatch of the No Solar scenario where negative values indicate hours of the day when the generator category is being dispatched less than in the No Solar scenario.

costs by approximately \$10 Million per year. This 3% increase is small when compared to the overall reduction in total dispatch cost.

Second, 22,500 GWh of solar generation reduces peak demand by 2.6-3.2 GW and increases net load flexibility requirements. Solar generation is not always closely aligned with load, but it is aligned enough to reduce the amount of thermal generation capacity needed by the electricity system during peak demand. However, the solar PV arrays only reduce annual peak demand by 15-23% of their installed capacity. Solar will eliminate the need for some existing dispatchable capacity, however most of the generators in the generator fleet will still be needed to meet peak summer demand, though they will be utilized for fewer hours during the year. Solar will also intensify ramping and volatility, particularly during shoulder seasons, requiring spare capacity to be available to provide increased system flexibility.

Third, solar affects how dispatchable generation is utilized in ERCOT. There appear to be two effects that influence this utilization. One, solar tends to reduce day-time net load which displaces higher-cost generators and reduces total dispatch cost. Slow-ramping, mid-load generation provides much of the flexibility needed to accommodate this net load reduction. Two, solar requires greater system flexibility, and, without broader system changes, needs dispatchable generators to support its large-scale integration, some of which are expensive faster-ramping generators that increase total dispatch cost. This dichotomy along with relatively small reductions to the annual maximum net load are notable characteristics of an electric grid with large solar penetration. This situation presents opportunities for demand response, electricity storage, and other supporting technologies to gain additional value by reducing solar integration costs.

Fourth, solar generation reduces emissions and water consumption. If carbon dioxide emission reductions, water conservation, and other environmental considerations continue to gain support, solar technology could be an important contributor for realizing those goals. For instance, if CO₂ were priced at \$10/ton and SO_x and NO_x at \$10k/ton, the emissions reductions from these solar scenarios would contribute an additional \$350 million in value.

The differences in the value of solar generation based on location and orientation can be explained by comparing the integration costs of the different solar scenarios. The integration costs from the UC&D simulations can be categorized as flexibility costs and thermal utilization costs. Transmission constraints, which can also contribute to integration costs, are ignored in this

model. When compared to the other scenarios, the East scenario did not excel in efficient power plant utilization or reduced flexibility requirements and was the worst scenario at minimizing total dispatch cost. Even though the East array is better aligned with the seasonal load of the ERCOT market, its daily summer generation peaks a few hours before the peak demand. This incongruence should be examined in future studies to see if solar arrays with both seasonal and daily correlations with peak demand can be employed. When comparing the South and West scenarios, the South array produces a net load profile with lower ramp rates and less volatility, which translates to lower flexibility requirements and lower costs. However, the West array utilizes the existing thermal resources more effectively by dispatching more of the efficient coal and natural gas combined cycle resources and less of the inefficient natural gas boiler and open cycle gas turbine resources as shown in Table 2. This efficient use of the thermal generation fleet also translates to lower costs. The West scenario reduces dispatch costs more than the South scenario by a non-trivial amount. This comparison strongly suggests that the total dispatch cost is influenced more by the efficient use of thermal generation assets than by flexibility requirements.

A number of these conclusions should be insightful as electric grids plan for future capacity expansion. Encouraging the growth of solar energy generation can be a good step towards achieving sustainability goals, but it must be done with care. The orientation and geographic location of solar panels within an electric grid not only affects emissions, but influences the generator dispatch, total dispatch cost, system flexibility requirements, and other parameters that grid developers might not have considered. This study aims to contribute new knowledge about the holistic affects of integrating solar generation into the grid that will help inform these grid development decisions.

6. Future Work

This study is meant to be an initial quantification of the impacts of solar generation in a wholesale electricity marketplace as demonstrated in ERCOT. While the results provide some outcomes about the benefits and disadvantages of solar generation with different time profiles, this study provides insufficient direction for choosing an optimal solar layout. Future work will attempt to develop additional solar scenarios with varying geography, orientation, tilt, and tracking capabilities that efficiently use dispatchable gener-

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ation, more effectively reduce maximum annual net load, and have limited impacts on flexibility requirements. The success of these different solar scenarios in reducing total dispatch costs can be discerned via ERCOT UC&D simulations.

Eventually we would like to include capital costs, transmission integration costs, and prices on environmental externalities to provide economic comparisons between different scenarios with new capacity. In this analysis, for example, it would be interesting to compare the total installation cost of the South and West arrays to determine the time frame over which the increased capacity and transmission costs of the West array would be recovered by the reduction in total dispatch cost.

Finally, we plan to implement some improvements to the ERCOT UC&D model used for this analysis. By updating the model to represent the 2014 ERCOT market, adding transmission constraints, and improving its ability to reproduce pricing spikes and non-marginal cost generator bidding behavior, we hope to increase its accuracy and usefulness. We hope these improved UC&D design methodologies will benefit other electric grids with large amounts of renewable generation assets.

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