NATIONAL ENERGY TECHNOLOGY LABORATORY

AN EVALUATION OF ELECTRICITY NET LOAD PROFILES AND THE BASELOAD GENERATION CONCEPT

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Abstract

Least cost planning and flattening system demand through demand-side management (DSM) was once a driving concept for system planning. This planning approach addressed the idea that flat demand profiles were preferred because they could be served efficiently by baseload generators such as pulverized coal and nuclear plants. New generation construction was driven by peak demand growth, and thus flattening loads delayed new construction and increased baseload capacity factors.

As the focus turned to renewable portfolio standards (RPS) and subsidies for renewable power, the concept of flattening a system demand profile appears to have fallen in priority. This has resulted in concerns such as the infamous "duck curve" which creates a challenge for California utilities as the unequal match between demand and intermittent renewable resources have created net loads for dispatchable resources to serve at higher costs.

This paper provides an analysis of net load profiles (NLP) for several power system regional transmission organizations (RTOs): California (CAISO), Midcontinent Independent System Operator (MISO), PJM Regional Transmission Organization, and the Electric Reliability Council of Texas (ERCOT). The objective of this study is to answer the question: Would targeting a level demand profile and high baseload generation result in more efficient power systems, better balancing the use of renewable energy resources (RERs) and effective baseload capacity (EBC)?

In answering this question, an analysis was done by simulating the RTO power systems in 2030 as they are estimated to operate after RPS goals have been met by the states in each respective RTO. This future scenario is compared to another scenario in which it is assumed that there are no RPS regulations, and thus no RPS resources supplying electricity in 2030.

For the four RTOs, a total of 61 GW of baseload is foregone due to RPS goals. In addition to lost baseload capacity, there is also an estimated net loss of between \$0.8 billion and \$4.6 billion annually per RTO, up to \$10.4 billion annually excluding transmission costs.

Therefore, these results suggest there is a balance that could be achieved in the use of RERs and conventional generation in order to achieve the most efficient power system operations. This study also introduces two new measures for analyzing baseload generation: 1) effective baseload capacity level (EBCL), and 2) a load variability index (LVI). Both of these will be useful in performing future analyses.

Disclaimer

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ACRONYMS AND ABBREVIATIONS

AEO	Annual Energy Outlook
AUSC	Advanced ultra-supercritical
Btu	British thermal unit
CAISO	California Independent System Operator
CRF	Capital Recovery Factor
CCS	Carbon capture and storage
COE	Cost of electricity
CoV	Coefficient of variation
DMR	Demand Management Resources
DOE	Department of Energy
DR	Direct response
DSM	Demand-side management
EBC	Effective baseload capacity
EBCL	Effective baseload capacity level
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas
GE	General Electric
GLP	Gross load profile
GW	Gigawatt
IGCC	Integrated gasification combined cycle
IOU	Investor owned utilities
ISO	Independent system operator
ITC	Investment tax credit
kWh	Kilowatt-hour
LCOE	Levelized cost of electricity
LVI	Load Variability Index
LMP	Locational Marginal Price
$M	Million dollars
MESA	Mission Execution and Strategic Analysis
MHI	Mitsubishi Heavy Industries
MISO	Midcontinent Independent System Operator
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Electric Reliability Corporation
NETL	National Energy Technology Laboratory
n/a	Not available
NGCC	Natural gas combined cycle
NLP	Net load profile
NREL	National Renewable Energy Laboratory
O&M	Operation and maintenance
PC	Pulverized coal
PJM	PJM Interconnection
PTC	Production tax credit
PV	Photovoltaic
RECS	Renewable energy certificates
RER	Renewable Energy Resources
RPS	Renewable portfolio standards
RTO	Regional transmission organization
SC	Supercritical
SLF	System load factor
ST	Steam turbine
U.S.	United States
VRE	Variable renewable energy

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EXECUTIVE SUMMARY

Beginning in the 1980s, demand-side management (DSM) became a driving concept for system planning, with demand leveling playing a significant part to saving on the cost of new generation[1]. This planning approach also addressed the idea that flat demand profiles were preferred because they could be served efficiently by baseload generators, such as pulverized coal power plants and nuclear power plants.

Today, primarily due to renewable portfolio standards (RPS) and subsidies for renewable power, the concept of flattening a system demand profile and least-cost optimization appears to have fallen in priority. This has led to concerns regarding imbalances in electricity supply and demand (graphically represented by the "duck curve"), which is the current challenge of California utilities — trying to solve the economic dispatch issues caused by the unequal match between demand and intermittent renewable resources.

This report provides an analysis of net load profiles (NLPs) for several independent system operators (ISOs)/regional transmission organizations (RTOs): California Independent System Operator (CAISO)[2], Midcontinent Independent System Operator (MISO), PJM Interconnection (PJM), and the Electric Reliability Council of Texas (ERCOT). The objective of this study is to answer the question: "would targeting a level demand profile and high baseload generation result in more efficient power systems?"

The short answer is "Yes". This inital study indicates that costs could be anywhere from $0.8 to $10.4 (see Exhibit ES-1) billion per year after all RPS goals are met for these four RTOs. There are two cases that are compared to arrive at these numbers: the Full RPS case and the No RPS case for each RTO. These cases involve modeling each power system in 2030, with and without renewable energy attributable to RPS goals.

Exhibit ES-1. Energy Costs for 2030 No RPS and Full RPS 2030 Cases

ISO/RTO	No RPS 2030 Total Energy Cost	Full RPS 2030 Total Energy Cost	Total Annual Energy Benefit (Cost) for RPS Efficiency
	$M	$M	$M
CAISO	**$12,658**	**$13,469**	**($811)**
ERCOT	**$11,248**	**$13,201**	**($1,953)**
MISO	**$21,320**	**$24,373**	**($3,053)**
PJM	**$22,092**	**$26,672**	**($4,580)**
Total	**$67,318**	**$77,715**	**($10,397)**

[1] There is no specific date that marks the beginning of demand side management In addition to the author's experience, DSM is cited by Wikipedia as publicly introduced by the Electric Power Research Institute during that time. Also, "Energy Demand Side Management: New Perspectives for a New Era", Sanya Carly, Journal of Policy Analysis and Management, Volume 1. pp 6-32..

[2] All of California is included in this use of CAISO except for the PacifiCorp-West balancing area.

The energy costs shown in Exhibit ES-1 reflect the application of the LCOE to the VRE using IHS Markit estimates of LCOE [1,2] applied to wind and solar resources.

If capital costs of high efficiency natural gas and coal generation are included in these comparisons, lower cost savings occur (Exhibit ES-2). However, the variable renewable energy (VRE) resources are primarily credited for supplying only energy, not recovering revenue for capacity supplied. Assuming that capacity payments would be obtained by most of the dispatchable generators to help make them financially whole, the energy market would be about $10.4 billion more costly on an annual basis for the four regions due to RPS policies and lower effective baseload capacity levels (EBCLs). This excludes needed VRE backup generation and transmission costs. Although, because the ERCOT market is an energy-only pricing market, Exhibit ES-2 would better reflect the ERCOT costs [4].

Exhibit ES-2: All-in Costs for 2030 No RPS and Full RPS 2030 Cases

ISO/RTO	No RPS 2030 Total Annual Cost Capital Included	Full RPS 2030 Total Annual Cost Capital Included	Total 2030 Benefit (Cost) for RPS Efficiency Capital Included
	$M	$M	$M
CAISO	$16,830	$15,436	$944
ERCOT	$15,666	$16,718	($1,053)
MISO	$36,639	$37,925	($1,286)
PJM	$21,154	$25,344	($4,190)
Total	$90,289	$95,423	($5,585)

This study is preliminary because of the costs unaccounted for related to additional cycling costs which have been estimated in several studies [5,6,7], and the additional transmission and distribution costs required for delivering distant wind farm power and integrating solar power when it is located on rooftops. There would also likely be a significant amount of batteries purchased by consumers, residential and commercial, that would provide redundant backup capabilities. All costs associated with the VRE in the Full RPS cases therefore are not included here. Of course, some costs associated with the No RPS case are also not included, such as transmission connection costs. However, given the results of this study, there is a clear indication that not focusing on incentivizing a flat load profile, as with DSM, and installing high levels of renewable energy resources (RERs) to meet the RPS goals will lead to higher consumer electricity costs.

Another aspect of the cost results are the assumptions for capital and fuel costs. One assumption is that about 16 GW of solar generation is added in CAISO assuming continuous declines in costs, making the levelized cost of electricity (LCOE) for solar about $68/MWh. This compares very favorably to new coal and natural gas generation. Natural gas prices are also set at about $6/mmBtu in 2030 depending on the power system (EIA's AEO 2018 Reference Case [3] was used), which assumes a doubling in levels from 2018, or a 6.2% annual rate of increases.

Uncertainty always plays a role in cost estimations, and if natural gas prices were to remain lower than projected, perhaps more NGCCs would be installed and shift the cost advantage further in ERCOT to the No RPS case. Also, since ERCOT is an energy-only wholesale market,

Exhibit ES-2 costs would be more appropriate to compare on a cost recovery basis[3]. There are, of course, many assumptions that could be argued to favor one type of resource or another, and therefore the methods demonstrated in this report may be applied in a more precise measurement of efficiency in an expanded analysis.

Focusing on the costs of an imbalanced power system, results confirm that by including costs that are not visible in the economic dispatch by applying the LCOE to VRE are imposing higher energy costs on customers. More visible costs in the economic dispatch would likely change the way VRE resources are used, or curtailed, due to high prices and being higher on the dispatch supply curve. It would be a matter of accounting to ensure appropriate payments are made if this method were implemented, but the visibility in the dispatch would be the effective outcome. Only the potential benefits of doing this are evaluated here.

In addition to measuring efficiency, this study also addresses how much the change in focus to VREs in electric power supply reduces the EBCL. It was found that about 61 GWs less of effective baseload capacity (EBC) could occur due to RPS policies. By measuring system operations costs excluding RERs, this study presents an alternate view on the cost of cycling imposed by intermittent resources in measuring the cost of a lower EBCL.

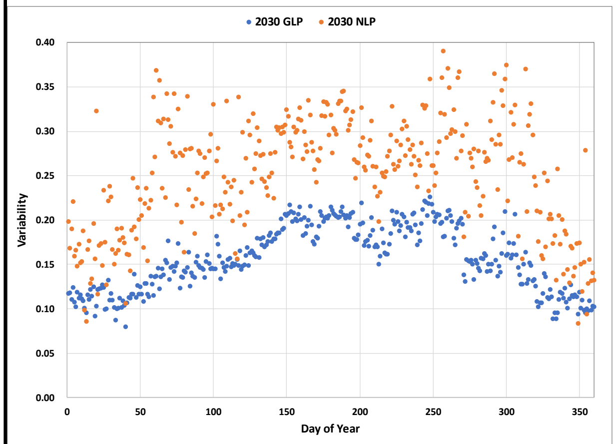
Two statistics were initially analyzed to assess load variability: system load factor (SLF), and kurtosis. A SLF is a measure of the total energy to peak demand and has values between 0.0 and 1.0. Kurtosis is often referred to as a measure of peakedness, or flatness, comparing the tails of a distribution to the mean of the distribution. Upon completing a detailed analysis of how well kurtosis addressed hourly variability, the coefficient of variation (CoV) and SLFs were applied to address variability over 24 hours. Through experimentation, a load variability index (LVI) was developed as a reliable measurement of daily load shape variability. As such, LVI calculations were made for daily load shapes: values close to zero point to flatter load shapes, which are more favorable for baseload generation and a higher EBCL.

Exhibit ES-3 shows the LVI comparisons for each power system in 2030. The No RPS is represented by the gross load profile (GLP), and the Full RPS is represented by the net load profile (NLP). Notice that there are distinguishable differences between the blue and orange dots for the entire year (from left to right, 1-365 days are shown), the higher orange dots indicating more variability for the day they represent. The differences between the 2030 cases with and without VRE are shown in more detail in Section 3, indicating significant variability introduced in the Full RPS cases for each of the RTOs.

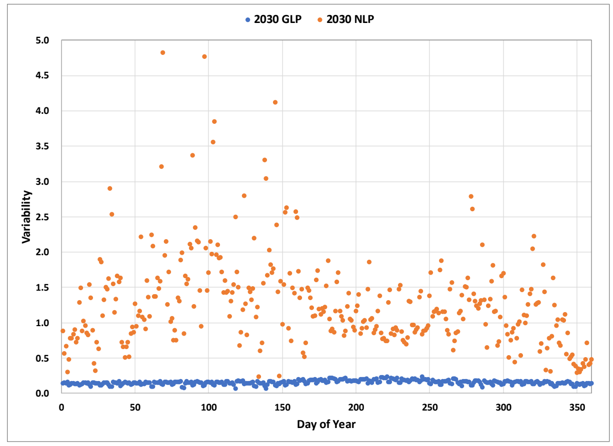
[3] In the ERCOT market, there are no capacity payments made to generators in the power market, so all revenue needed to make a generator financially whole must come through energy revenue.

Exhibit ES-3.Daily Load Variability Indices for 2030, Full RPS and No RPS Cases.

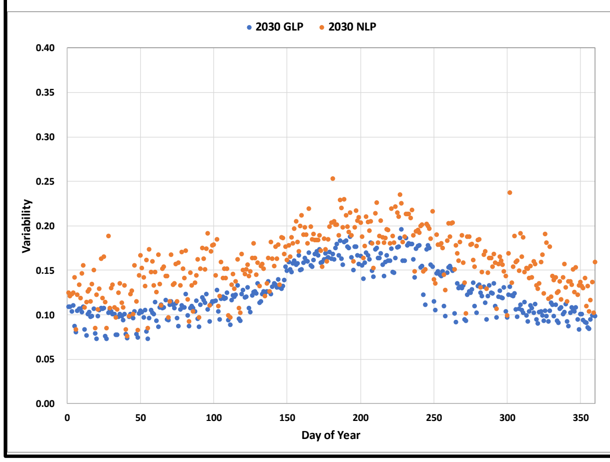
ERCOT 2030 GLP (blue dots) and NLP LVI



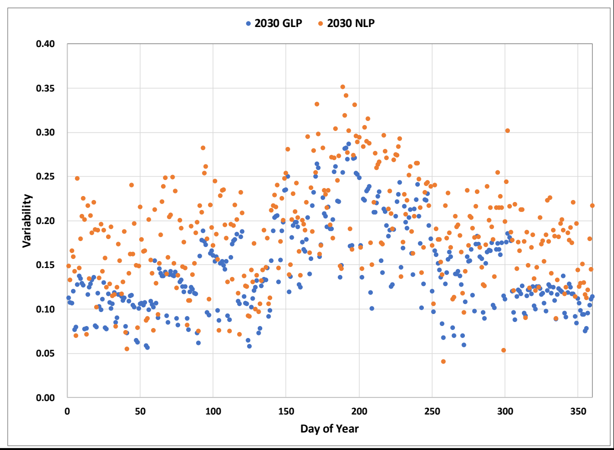
CAISO 2030 GLP (blue dots) and NLP LVI



MISO 2030 GLP (blue dots) and NLP LVI



PJM 2030 Gross (blue dots) and NLP LVI



Another analysis of load shape variability is shown in Exhibit ES-4, which shows the comparisons of annual SLFs for 2016 to the Full RPS and No RPS cases in 2030. The CAISO system was found to have the largest change in SLF, and relative flatness of load due to the implementation of RPS policies. The relatively large amount of wind and solar for the system size likely drives this result, creating more variability in the net load.

Exhibit ES-4. SLFs for 2016 vs 2030 No RPS and Full RPS Net Loads

ISO/RTO	2016 Annual SLF	2030 No RPS Annual SLF	2030 Full RPS NLP Annual SLF
CAISO	57%	58%	37%
ERCOT	56%	59%	50%
MISO	64%	63%	58%
PJM	59%	59%	56%

The EBCL is defined in this study as the minimum average 30-day demand divided by the expected capacity factor of baseload generation.[4] Exhibit ES-5 shows comparisons of the EBCLs for 2016 and the 2030 cases. Note that even though the differences between the Full RPS 2030 and No RPS 2030 EBCLs are close, CAISO and ERCOT would experience the greatest relative loss of baseload capacity because of their smaller system sizes.

Exhibit ES-5. 2016, 2030 No RPS, and RPS 2030, Effective Baseload Capacity Levels

ISO/RTO	2016 EBCL (GW)	RPS 2030 NLP EBCL (GW)	No RPS 2030 EBCL (GW)	2030 Differences due to RPS (GW)
CAISO	28	14	27	**13**
ERCOT	38	30	44	**14**
MISO	79	77	95	**18**
PJM	88	81	97	**16**
Total	233	202	263	**61**

The primary findings are that the VRE in MISO reduces the EBCL the most of the four RTOs, shaving off about 18 GW of effective baseload capacity using 85 percent as the capacity factor in the 2030 Full RPS case. The ERCOT, CAISO, and PJM systems are projected to lose 14 GW, 13 GW, and 16 GW of EBCL, respectively, by 2030. A total of 61 GW of EBCLs would therefore be circumvented as a result of RPS policies.

All of the load shape statistics discussed indicate that having an RPS in place results in, and will continue to result in, a net load that would be served at a lower EBCL in 2030.

As presented, the other RTO cost results point to a clearer benefit to the No RPS case and a higher EBCL; for, the differences are more reliant on the cost of an NGCC and fuel price assumptions rather than more or less USCPC installed. Again, lower natural gas prices would increase the amount that could be saved with less VRE in the power systems.

As mentioned, these costs do not reflect additional transmission costs attributable to delivery of any new generation to load areas. For instance, the ERCOT CREZ transmission projects reportedly cost about $7 billion to build [9]; if amortized over 30 years using an 8 percent weighted average cost of capital, about another $620 million would be added to the annual costs in ERCOT for CREZ, and borne by consumers in their electric bills.

In summary, when comparing only energy-based costs, all systems resulted in higher annual energy costs from $1 to $4 billion in each system for the 2030 Full RPS case; all-in annual costs

[4] For instance, if the minimum average 30-day demand in ERCOT is 40 GW, and baseload generation is expected to operate at 85 percent or higher, 40/0.85 or about 47 GW of capacity would the EBCL. The 85 percent capacity factor includes four weeks of annual maintenance and a 5 percent forced outage rate, both assumed reasonable for baseload generation.

are estimated at $0.5 billion to $4 billion higher for each system for the Full RPS case in 2030. This cost analysis implements the idea of deposing the current concept for dispatching VRE generation, which is to assume VRE energy has a “zero energy cost.” A case can be made that wind and solar are primarily energy resources due to the intermittency characteristic; capital costs are required to capture the energy, and energy revenue is required to repay the capital costs.

Based on these results, the answer to the question, “would targeting a level demand profile and high baseload generation result in more efficient power systems?” is yes. Thus, the concept that a flatter electricity load can be served more efficiently with resources that operate at a near constant level seems intact.

Findings suggest that, for the four RTOs in this analysis, about $10 billion dollars more in annual costs will be incurred in 2030 if all RPS targets are met, along with the other assumptions for the fuel prices in the AEO 2018 Reference Case [3]. Other costs not included in this cost estimate could add significantly to the annual totals.

Including the other power systems in the U.S.[5] not modeled along with other backup and transmission costs could possibly lead to more savings. Seeking a more balanced resource mix from an efficiency and system operations perspective could help to realize these savings.

[5] Additional power systems would be in the SERC, ISO-NE, SPP, and WECC sub-systems.

1 INTRODUCTION

In the 1980s until about 2000, having a flat load shape to serve was considered a goal for investor owned utilities (IOUs). Demand-side management (DSM), or load management, which originated in the early to mid-1980s, involved trying to create a level load to serve with the most efficient generation, supported by the idea that high peak loads were costly. Having a high system load factor (SLF)[6] was considered a measurement of an efficient load level, and a low SLF was a measure of a high system peak relative to other hourly demands, and costlier to serve. Increasing peak demand leads to building more generation. Striving toward a high SLF and focusing on power system optimization seems to have fallen lower in priority to renewable resource development and renewable portfolio standards (RPS).[7]

Demand management is still in place today, but for the narrower purpose of reducing demand whenever capacity is falling short of meeting operating reserve or power. Alternatively, power plant developers and owners are encouraged to make their plants as flexible as possible to serve the varying net loads that remain after renewable power is dispatched ahead of what was formerly referred to as baseload resources.

The paradoxical situation promoting this behavior is that renewable energy typically is sold on an energy basis, rather than to an electric distribution company or local load aggregator with a capacity payment involved in the bilateral contract. Furthermore, RTOs set the amount of solar and wind capacity that could obtain a capacity payment based on historical analyses, which is 50 percent or less of the installed capacity (see Exhibit 2-3). Thus, for the purposes of this study, variable renewable energy resources (VRE) are considered energy resources. Yet, they are represented as free energy[8] in the dispatch queue. With an assumed zero energy price, VRE are dispatched first and in most instances are not curtailed, unlike dispatchable resources. The costs imposed on other power suppliers have been well documented and include cycling related operation and maintenance (O&M), and lost revenue due to the assumed zero energy cost that forces other generation higher in the supply queue.

The current study assesses how power system load shapes, defined by the previously identified RTOs and their boundaries, have evolved over the years and what each might evolve to if they continue the current growth path and RPS goals are met. The efficiency of serving the net load is assessed, which consists of comparing the system load shapes with the RPS goals fully met to the system load shapes without RPS resources. This is done to estimate the trade-off in efficiency and costs due to the VRE being dispatched instead of having the higher baseload energy that would be in place if no VRE had been built.

Thus, there are two primary cases evaluated in this study: 1) the Full RPS case, and 2) the No RPS case. The load shapes for each case are compared to assess variability due to the VRE, and support for the cost differences for the Full RPS and No RPS power cost comparisons.

[6] System load factor is defined as the annual energy divided by the product of peak demand times 8760 hours. It is calculated the same way as capacity factor for a power plant and defined in Section 2.

[7] The use of subsidies for renewable energy sources may enable some to be included in a least-cost resource plan, for without subsidies they would be excluded from the plan.

[8] Even though there are reports of negative energy prices being submitted by wind resources, this does not reflect actual energy costs. It is simply the amount a wind owner is willing to pay for delivery of energy in order to obtain all energy payments it can, which would include contract prices for delivery, production tax credits, and renewable energy certificates (RECs).

Section 2 describes the methods used to compare the flatness of load shapes. Section 3 presents the comparisons and analysis of the load shapes, and implications for baseload generation. It also provides an analysis using ProMod™ to simulate the economic dispatch of power systems with and without RPS to assess the efficiency trade-offs between the Full RPS and No RPS cases.

2 METHODOLOGIES FOR NET LOAD PROFILES AND EFFICIENCY

2.1 NET LOAD PROFILE DEVELOPMENT

A net load profile (NLP) is defined as the consumer demand remaining to be served after the use of VREs, which are the first resources to be applied to consumer demand. The ProMod™ hourly economic dispatch modeling software was used to model all power resources in each ISO/RTO region. The regions modeled include California Independent System Operator (CAISO), PJM Interconnection (PJM), Midcontinent Independent System Operator (MISO), and Electric Reliability Council of Texas (ERCOT). The dispatch model contains all electric power generation, with renewable resources such as wind and solar being represented by supply profiles obtained from the National Renewable Energy Laboratory (NREL) renewable energy databases. In each RTO simulation, the ProMod™ model has the capability to output the 8,760-hour demand load shape as modified by the simulated operation of all renewable resources. and produces a NLP by subtracting the VRE supply profiles from the gross load profile (GLP). Thus, the GLP is the electricity demand prior to the dispatch of the renewable resources (or when there are no VREs) and is the profile type to which the No RPS case refers. Using the ProMod™ model, the year 2030 was chosen to simulate when all RPS goals will have been met, and NLPs can be compared to the GLP to determine the estimated influence of the RPS requirements, or VRE supply, on the GLP. Using economic dispatch, the NLP and GLP in 2030 can be evaluated for each RTO to assess how efficiently each electricity demand profile can be served. The methods used for the evaluation of daily, seasonal, and annual load profiles are described below.

2.2 EVALUATING ANNUAL AND SEASONAL LOAD SHAPES

A statistic known as system load factor (SLF) was used in evaluating the differences in the annual and seasonal NLPs and GLPs. An SLF is similar to a capacity factor for a generation unit, but it is for the load rather than generation. It is defined as follows:

$$SLF_t = [Energy_t / (Peak\ Demand_t \times Hours_t)] \times 100$$

Therefore, the SLF is a percentage that is 100 for a completely flat load shape (i.e. if demand were 100 MW for every hour of the year, the annual SLF would be 100). The SLF can be calculated for any time period from daily to annual. The seasons that were defined for comparing the SLF to the demand load shapes for relative flatness are December-February, March-May, June-August, and September-November. Just as with the daily load shape comparisons, a flatter load shape during the respective time periods is theoretically preferred because of the efficiency with which they can be served by base load generation.

The SLF is scalable to any time period; therefore, it is potentially a useful measure to include in hourly or shorter time periods. This is why it was added to the LVI.

2.3 Evaluating Daily Load Shapes

Daily load shape variability was evaluated by comparing three statistics, kurtosis and the coefficient of variation, and another statistic called the Load Variability Index (LVI). The LVI was developed from analyses of daily load shapes and how well kurtosis and the CoV could indicate the most desirable daily shape when comparing any two daily shapes. It was found from visual analyses and comparison of kurtosis, CoV, and daily SLF values.

The equation used to calculate kurtosis is as follows [9]:

$$\left\{\frac{n(n+1)}{(n-1)(n-2)(n-3)}\sum\left(\frac{x_i-\bar{x}}{s}\right)^4\right\} - \frac{3(n-1)^2}{(n-2)(n-3)}$$

where:

Xi = each hourly demand for a 24-hour day

$\bar{X}$ = average hourly demand for 24-hour day

n = the number of hours in a day

s = the standard deviation

It was found that in trying to use kurtosis, it was not consistent in resulting in a lower value for daily shapes that have "duck curve" characteristics. Namely, as demonstrated by Westfall[10], there can be inconsistent results in kurtosis values if it is relied on to characterize "peakedness", mainly because of the relationship kurtosis measures between the tails in a normal distribution. A low kurtosis value, for example, "indicates that the sample contains many observations that are a moderate distance from the center (in value *sic*) and few outliers that are far from the center" [11]. In other words, some statisticians state that a low kurtosis value indicates a flatter distribution. The point of contention lies in the kurtosis not measuring the flatness of the peak, but the closeness of the tail values to the values in the peak. The tail values are the lowest demand hours during a 24-hour day. As appealing as it was to use kurtosis, kurtosis could not provide the most favored load shapes when steep "duck curve" shapes were compared.

Another metric that measures variability, similar to SLFs, is the coefficient of variation (CoV), defined as the standard distribution of the sample data, normalized to the mean. It is a simple calculation, dividing the standard deviation by the mean as follows:

$$\text{Coefficient of Variation} = \frac{\sqrt{\dfrac{\sum(x-\bar{x})^2}{n}}}{\dfrac{\Sigma x}{n}}$$

The variables are defined as described for kurtosis above. Similar to kurtosis, it had a correlation to kurtosis of about -0.65 when annual values (365 daily values) were compared to kurtosis values for the same shapes. However, although the CoV was an improvement to using kurtosis, it still did not meet the criteria being set for having a statistic that measured daily variability consistently. For instance, a comparison of the CoVs calculated for two daily load shapes using the SLF as another gauge for comparison revealed that in some comparisons, a low CoV did not occur for the load profile with the highest SLF. Recall that a high SLF suggests a flatter load shape. Yet, using SLF by itself clearly cannot account for daily variability because it does not account for deviations from the mean. Hence, the CoV seems to address that need. Therefore, a variability index, the LVI, was calculated by dividing the CoV by the SLF:

$$\text{Load Variability Index (LVI)} = \text{CoV} / \text{SLF}$$

After many comparisons were made to verify that the LVI was sufficient in capturing daily variability by having CoV in agreement with the SLF in determining close comparisons, the LVI was selected as the best measure for comparing net load profiles to gross load profiles. Lower values of LVI indicate less variability around the average daily demand levels. The appealing aspect of this factor is that, when it is broken down into the variables for a simplified equation, it simplifies to:

$$\text{LVI} = \sigma \text{ x Peak} / \mu^2$$

This is appealing because the daily peak demand and the standard deviation (σ) are compared to the mean (μ). Note that if the peak demand is equivalent to the standard deviation, the equation would be σ^2 / μ^2. Therefore, the flatter the load shape the lower σ is and the higher SLF is, driving the LVI closer to zero.

2.4 MEASURES OF EFFICIENCY

The objective of encouraging users of electricity to use various devices to shift their demand from the peak hours of the day to off-peak and shoulder periods is primarily to increase the efficiency of baseload generation and avoid the need for new resources[9]. The practice of demand management is still being implemented today, with certain devices and operations being paid to not be in use during certain peak hours of the day, or when directed by an ISO/RTO.

With the priority of meeting RPS goals, the "flattening demand" aspect of demand management has apparently taken lower priority, or at least has diminished in visibility. Demand response (DR) might be confused with demand management, and it is a subset of demand management because it is controlled during the economic dispatch when called upon as opposed to efficient lighting or refrigeration, which is a reduced level of demand not controlled during economic dispatch. The use of DR may decline due to stricter participation standards such as those being implemented by PJM [12] The amounts being practiced are about 5 percent of the system demand in PJM, and not likely sufficient to alter load shapes enough to change the type of generation that will be built. For this study, the focus is on changes made by renewable

[9] Demand management includes encouraging electric customers to use the most efficient appliances, motors, and lighting. There are several appliances and motors that run many hours of the day, and demand management would thereby reduce the need for baseload generation in addition to peaking resources. Today, demand response focuses more on reducing peak demand such as cycling off AC, whereas efficiency improvements seem to entail appliances, lighting, and motors that operate during all hours of the day.

resources driven by RPS goals, and the demand management is included in the load shape at a stable level.

Efficiency in an electric power system is typically measured by heat rates for generation. The higher capacity factor at which a generation unit operates, the more efficient the generator. Ultimately, efficiency is measured by operating at the lowest cost possible, which is achieved by having low heat rates. Therefore, in this study, comparisons are made between the annual costs of generation units when serving the demand in the GLP to the demand in the NLP. Furthermore, since the GLP consists of the demand without renewable resources, additional generation was added to the systems to meet system peak reserve margin. New combined cycle (natural gas combined cycle [NGCC]) and coal generation are added appropriately to meet the reserve margins in each RTO.

2.5 Phase 1 Modeling

The ProMod™ modeling for this report falls into two separate phases. Phase 1 involves taking established models of the four ISO/RTOs chosen for the study, and modifying them as follows:

- Base model data was obtained from ABB and PJM.
- Base models were updated to the most recent Energy Information Administration (EIA) Annual Energy Outlook (AEO) [3] natural gas price forecast through the study period of 2030.
- Base models were updated to reflect new certain capacity scheduled to come online, and any certain retirements using Ventyx Velocity Suite™ information.
- If necessary, a base model was updated by adding VRE generation to meet its Full RPS goals by 2030. Either solar or wind generation was chosen based on what was added into the ISO/RTO through 2017.

Therefore, this phase provided the load shapes that were compared on a daily basis using the LVI, and on quarterly and annual bases using SLFs.

2.6 Phase 2 Modeling

The Phase 2 modeling was used to make comparisons of system prices and costs between a Full RPS case and a No RPS case for each RTO in 2030. In all, two types of cases were developed in this phase of modeling: 1) a Full RPS case, and 2) a No RPS case. For the 2030 cases, an attempt was made to develop the No RPS case as close as possible to the generation mix in 2000 when the level of VRE in each system were low, and RPS policies were just beginning. These models were created by taking the Full RPS models from Phase 1 and removing all renewables from the economic dispatch. In this hypothetical future, coal and natural gas generation were added to bring the system up to meet the North American Electric Reliability Corporation (NERC) reference reserve margin for each ISO/RTO. Any new generation added to each case was assumed to be the most efficient generation likely to be built using the latest R&D estimates of efficiency improvements.

For the 2030 No RPS cases, it was assumed that the baseload generators would be upgraded or installed as the “best available” technology based on heat rate. To determine the best technology available, a review of current generator data in ProMod™ was compared to available literature for advanced systems. Exhibit 2-1 provides a summary of this review [13,14,15]. All technologies reviewed are expected to be available by the year 2030, the "Future X" NGCC case and the best advanced ultra-supercritical (AUSC) pulverized coal (PC) case heat rates and costs were used to represent the best available technology in 2030.

Exhibit 2-1. Technology comparison

Technology	η	Heat rate (Btu/kWh)	O&M-fixed ($/MWh)	O&M-Var ($/MWh)	Date Available
NGCC – GE 7F	51.80%	6583	3.36	1.75	2018
NGCC – Siemens H	53.70%	6355	2.98	1.59	2018
NGCC – MHI J Frame	56.50%	6036	2.67	1.42	2018
NGCC – Future X	58.80%	5801	2.73	1.56	2020
NGCC – Nine Mile Point	55.52%	5839	0.97	0.78	Current best
PC – John W Turk	36.15%	8634	4.53	1.59	Current best
PC – SC	40.70%	8379	9.6	9.1	2018
PC – AUSC	43.70%	7814	9.5	8.6	2021
PC – AUSC	43.90%	7769	9.5	8.5	2021
PC – AUSC	44.10%	7732	9.4	8.5	2021

In addition, since the dispatch of coal-fired power plants is heavily dependent on the cost of natural gas, an analysis was done using the best available technology scenarios to compare the cost of electricity (COE) for coal generation to the price of natural gas. The COE for a range of coal prices was also compared to determine the price point where coal-fired generation becomes more economical than gas-fired generation. This price point fell in line with the EIA AEO 2018 Reference Case [3] nominal prices for natural gas and coal, which was used for the 2030 price forecasts.

Exhibit 2-2. COE sensitivity to natural gas price

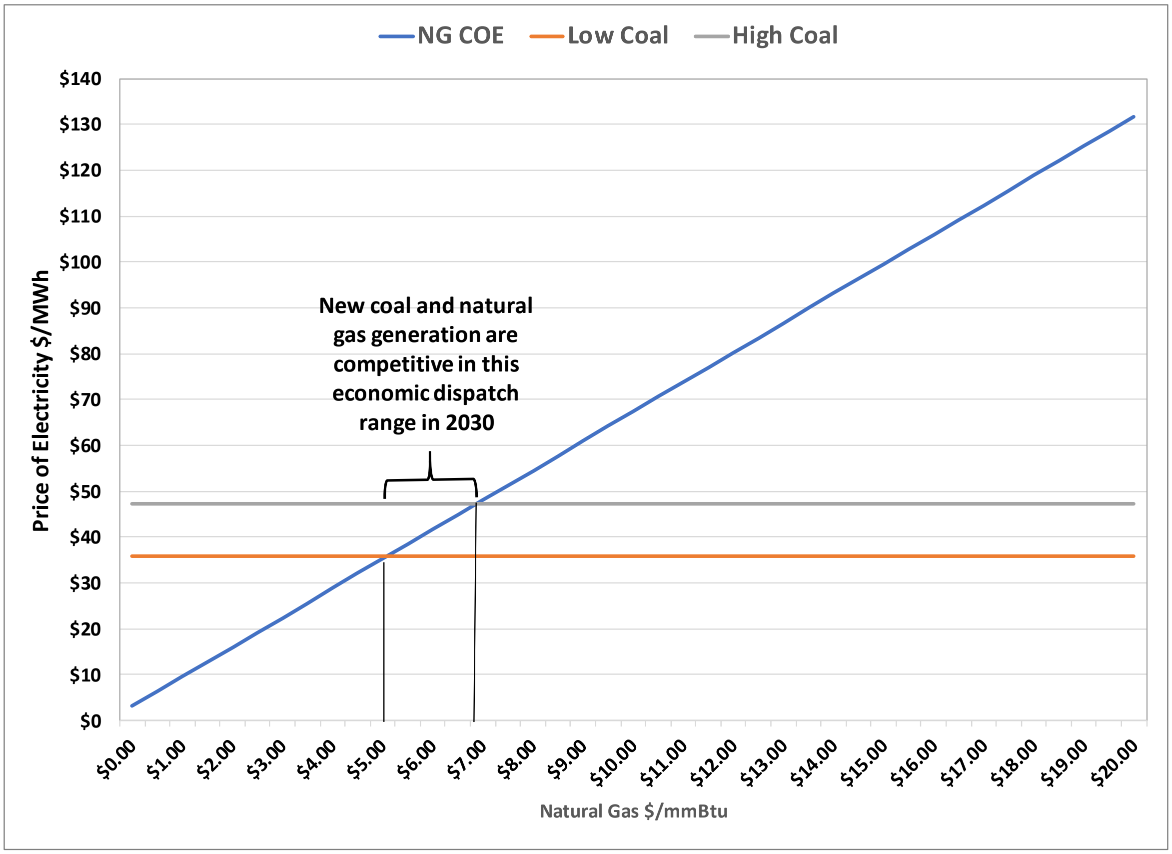


Exhibit 2-3 shows regional planning data used to update the models. NERC planning capacity credits for wind and solar generation, NERC reference margin from the latest Long-Term Reliability Assessment, as well as individual RPS goals for each region. In regions with multiple states, a sales weighted-average was calculated across the region.

Exhibit 2-3. Regional planning data

ISO	Wind Derate	Solar Derate	Reference Margin	RPS Goals
ERCOT	14%	77%	13.78%	10000 MW
CAISO	7.86%	24%	16.14%	50%
MISO	15.60%	50%	15.80%	12-15%[10]
Arkansas				n/a
Illinois				25%
Indiana				10%
Iowa				105 MW
Kentucky				n/a
Louisiana				n/a
Michigan				15%
Minnesota				25%
Mississippi				n/a
Montana				15%
North Dakota				15%
South Dakota				10%
Wisconsin				10%
PJM	13%	38%	16.60%	15-18%
Delaware				25%
Illinois				25%
Indiana				10%
Kentucky				0
Maryland				25%
Michigan				15%
New Jersey				50%
North Carolina				13%
Ohio				13%
Pennsylvania				18%
Tennessee				0
Virginia				15%
West Virginia				0%
DC				50%

[10] Actual percentage is uncertain due to the splitting of some state electricity by MISO and PJM.

Exhibit 2-4 shows model reserve margin calculations for the four regions studied. The models were updated in order to reach regional RPS Goals, or to fit the high tech No RPS scenario requirements for each region.

Exhibit 2-4. Modeling Reserve Margin Results

	ERCOT		CAISO		PJM		MISO	
	Full RPS	No RPS	Full RPS	No RPS	Full RPS	No RPS	Full RPS	No RPS
Reserve Categories	Capacity MW	Capacity MW	Capacity MW	Capacity MW	Capacity MW	Capacity MW	Capacity MW	Capacity MW
System Peak	81,286	81,286	57,955	57,955	163,108	163,108	150,909	150,909
Interuptible	1,917	1,917	2,832	2,832	138	138	5,924	5,930
Unserved Demand	79,369	79,369	55,123	55,123	162,970	162,970	144,985	144,979
Dispatchable Capacity	83,233	88,366	46,484	62,750	184,667	188,517	158,176	167,502
Wind Derated	3,385	-	810	-	3,031	-	7,446	-
Solar Derated	1,763	-	9,092	-	950	-	991	-
Other	318	318	7,712	1,294	1,884	1,884	1,312	1,262
Total Capacity	88,699	88,684	64,098	64,044	190,533	190,539	167,925	168,764
Reserve margin	11.8%	11.7%	16.3%	16.2%	16.9%	16.9%	15.8%	16.4%

Exhibit 2-5 shows the Regional RPS goals met, using results from the model runs. The ERCOT RPS goals were for an installed capacity, not a total energy.

Exhibit 2-5. Regional RPS Goals Met

	Total Energy (GWh)	RPS Goal (%)	VRE generation (GWh)	Percentage (%)
ERCOT		10,000 MW*	Wind 24,178 MW and Solar 2,290 MW	242%
CAISO	280,527	50%	128,958	46%
MISO	837,327	15%	120,517	14.7%
PJM	843,429	20%	145,771	17.3%

Exhibit 2-6 through Exhibit 2-9 show the installed capacity for the models as well as the resource mix of each RTO system in 2000. Due to the models being updated by adding new generation, and not retiring functional existing generation, in some cases it was not possible to exactly match the system resource mix in 2000 for the cases where advanced technologies are assumed.

Note that the type of technologies added change in the No RPS scenarios; this is because of the choices made for the high technologies.

Exhibit 2-6. ERCOT installed capacity

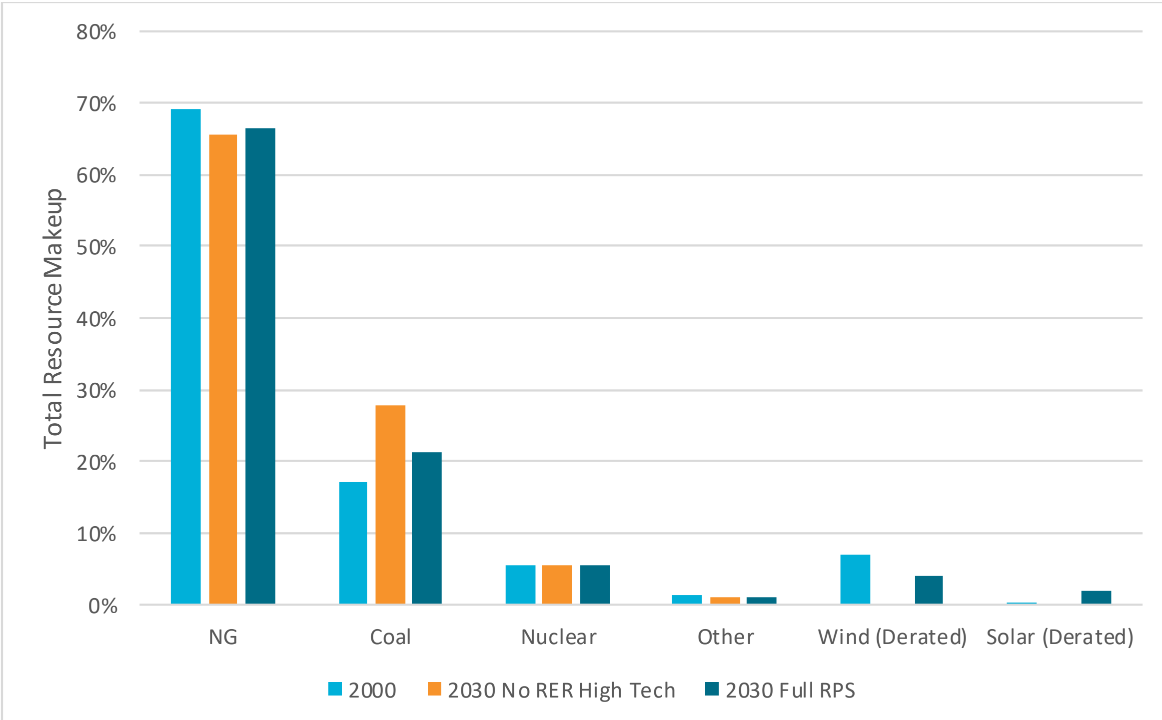


Exhibit 2-7. CAISO installed capacity

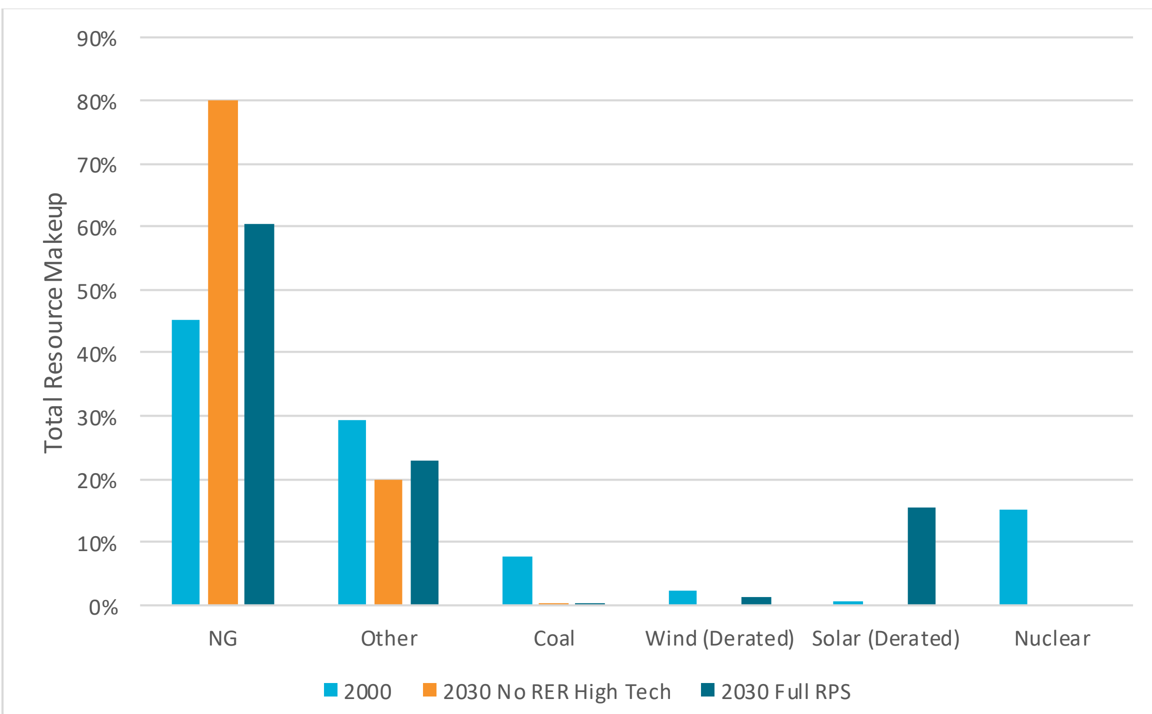


Exhibit 2-8. MISO installed capacity

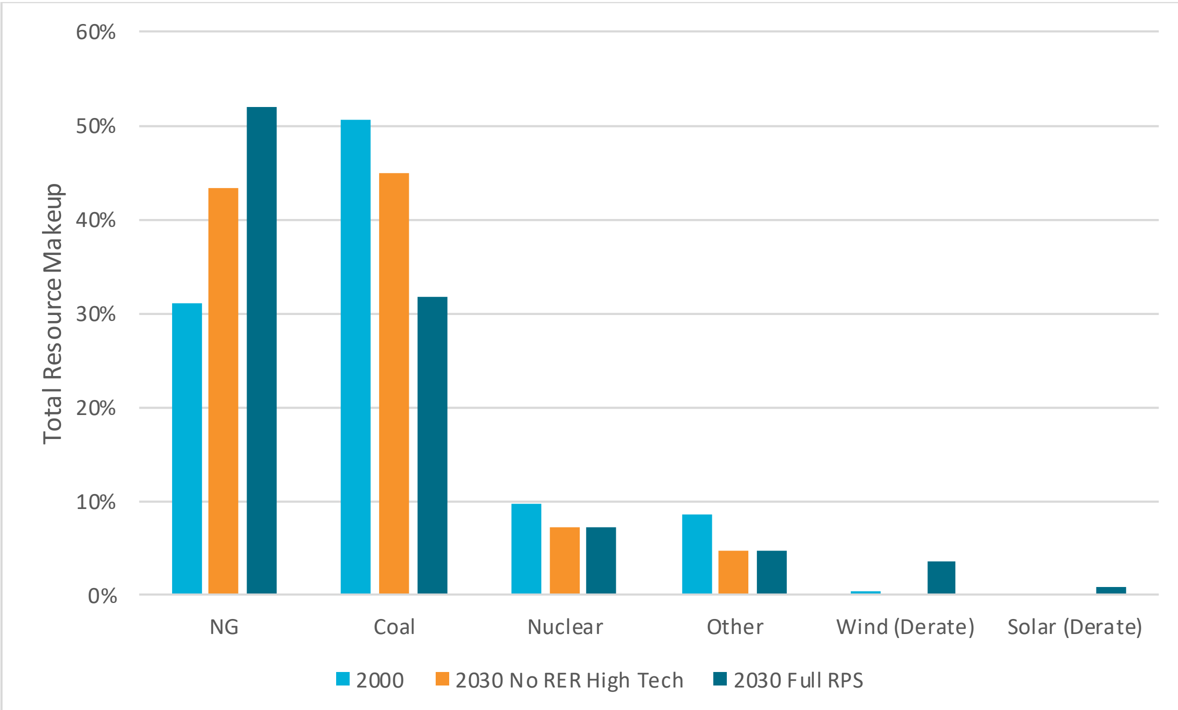
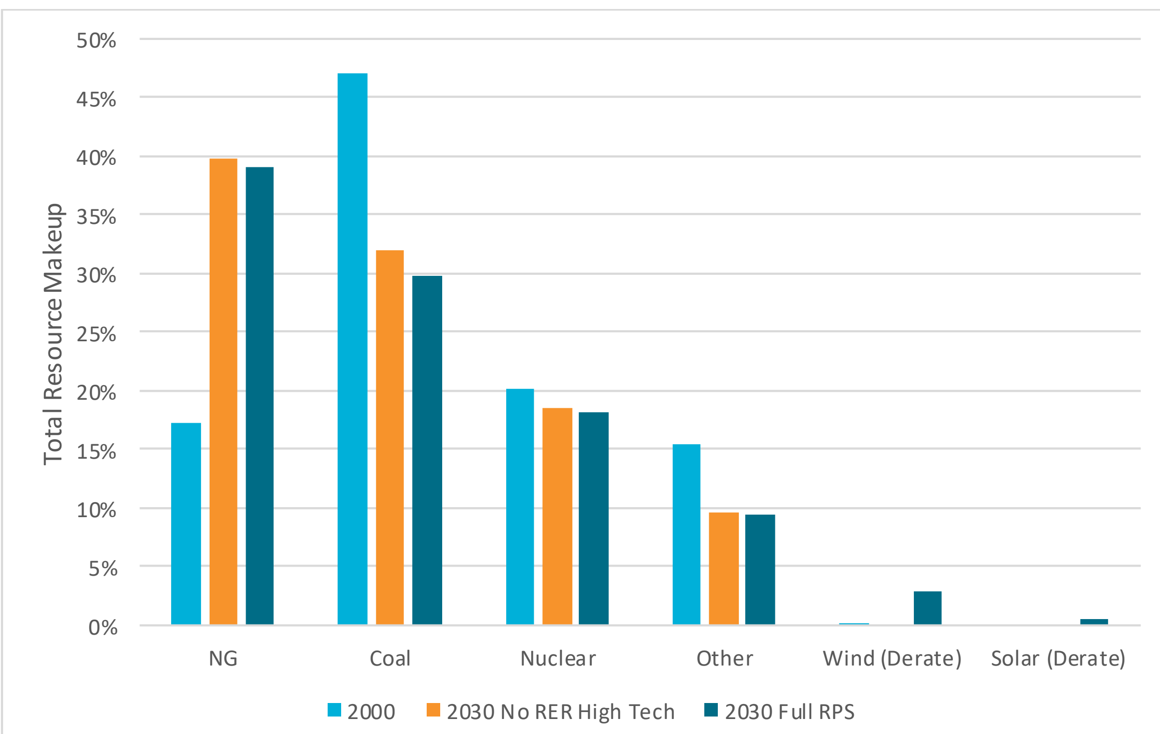


Exhibit 2-9. PJM installed capacity



3 RESULTS

3.1 LOAD SHAPE ANALYSIS

Phase 1 modeling revolves around analysis of load shapes and generation. The hourly load calculated by the program was analyzed for each ISO/RTO. Yearly and quarterly system load factors were calculated. Detailed quarterly results are shown in the Appendix: Additional Analyses.

The following exhibits show results for a Full RPS case, as well as a No RPS case; the respective load data are referred to as net load profiles and gross load profiles. The Full RPS case has the renewable generation subtracted from the full load, with SLFs calculated from that resultant net load. This provides a comparison between the full SLF, and the SLF seen by the rest of the generation once the renewables have dispatched. The yearly SLFs were combined with the generation calculated by two model runs, a Full RPS case, and a No RPS case to generate a picture of how each generation type contributed to the SLF. This provides a comparison point between installed capacity in a region, and the contribution of that capacity towards the system loads.

First, however, an historic view was developed using PJM as an example. Exhibit 3-1 shows the SLFs for the PJM system from 1993 to 2016 compared to the annual peak hour. The graph shows a near quadrupling of the annual peak hour, which is due to the enlargement of the PJM system across the eastern United States from population growth in addition to new utility members of the RTO. However, the SLF has stayed within a 12 percent range with no adjustments for weather, which could drive a lower SLF (high peak demand), or a higher SLF (moderate weather). This chart is intended to demonstrate the nature of the demand load profile without the influence of a significant amount of VRE. Over the 24-year period, the PJM load profile SLF remained about the same, but data shows a slight uptrend if a straight line is fit to it.

Exhibit 3-1. PJM Annual Peak and SLFs, 1993-2016

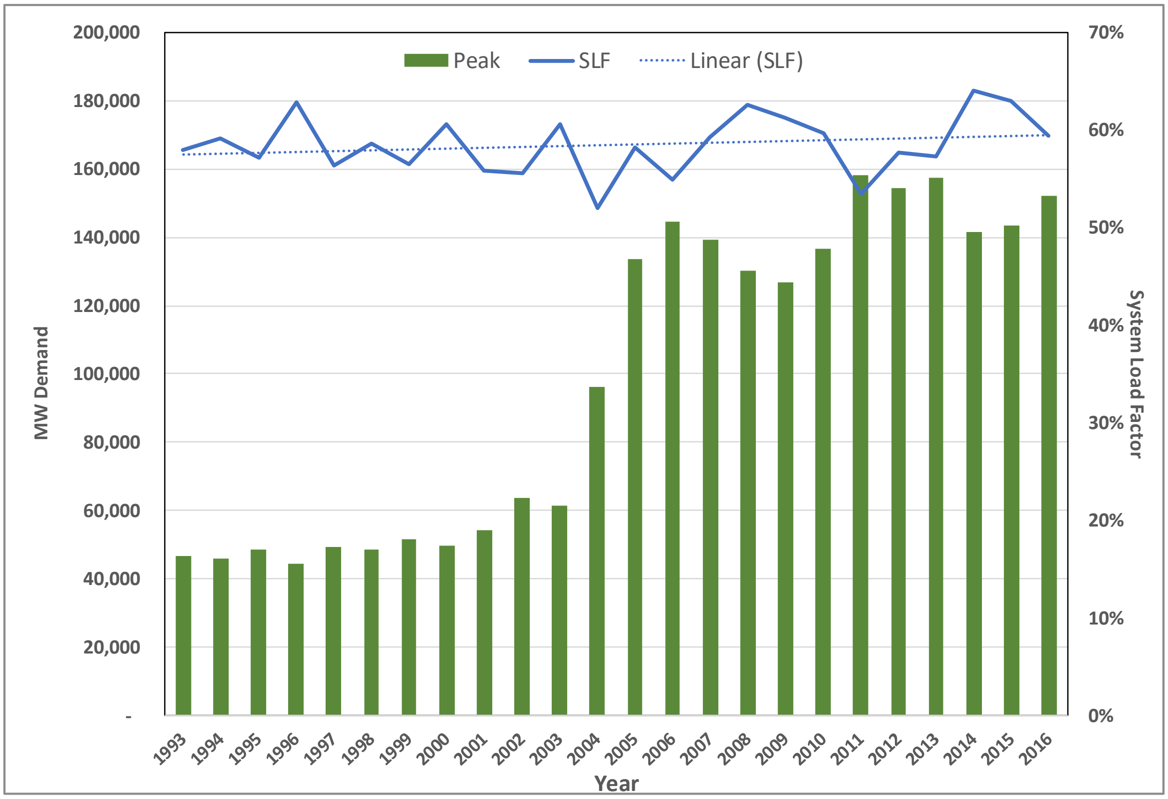
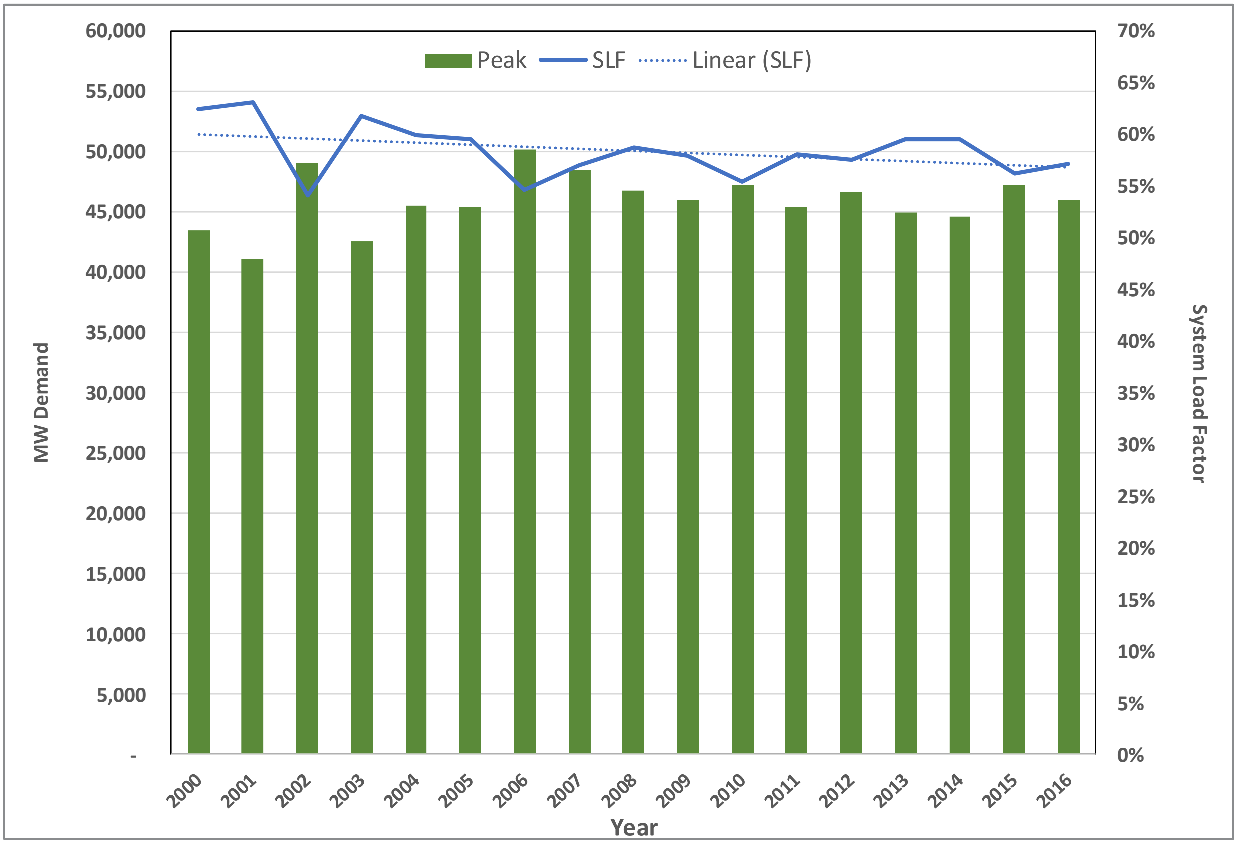


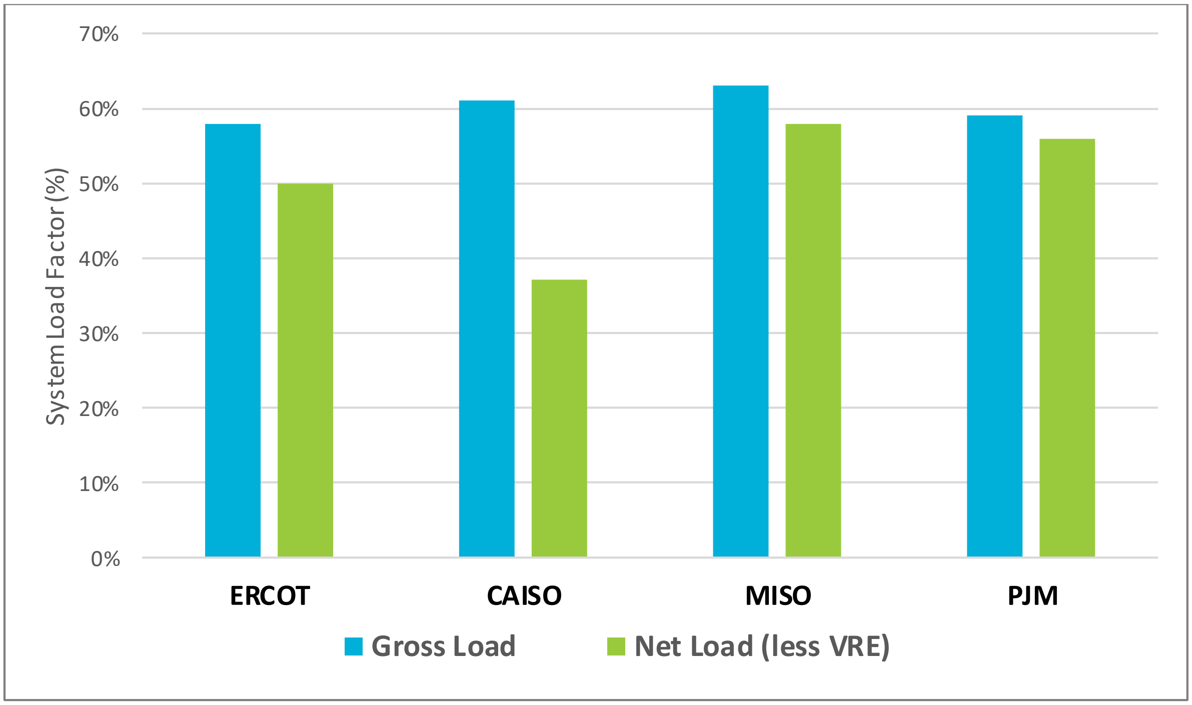
Exhibit 3-2 shows the annual peak demand for CAISO (bars) compared to the SLF from 2000 to 2016. Notice that the SLF also is within a 12 percent band over the sixteen years; however, the trend in SLF is downward. This contrasts with the up-trend seen in the PJM SLF, which supports the idea that more VRE leads to a less flat load shape, and therefore lower baseload generation. However, without weather normalization, there is no basis to claim there is a significant difference in early-year and later-year SLFs. One might conclude that permanent DSM technologies helped to maintain the SLFs so peak demand did not become excessive relative to the energy demand.

Exhibit 3-2. CAISO Annual Peak and SLFs, 2000-2016



The yearly SLF shown in Exhibit 3-3 shows that the MISO and PJM SLFs show a similar change between the gross and net loads, having about a 3-5 percent change from gross to net. The CAISO region shows the largest change, dropping over 20 percent, with PJM showing the smallest change in SLF.

Exhibit 3-3. Yearly ISO System Load Factors



In each region studied, the SLF was lower in the Full RPS case for the NLP. This effect varied based on renewable penetration in each region, with a lower SLF in the RPS case with higher renewable penetration. This indicates that a less flat load shape is available to be served by baseload generation, and thus a more inefficient system to serve. In order to assess how the baseload level might change from season to season, the quarterly SLFs were compared.

3.2 Daily Variability Analysis

As explained in Section 2, a load variability index (LVI) was used to compare the daily loads for each of the four RTOs. The purpose of evaluating daily load shapes is to assess whether adding VRE to power systems at the levels prescribed by RPS leads to more peaks and valleys in power systems, and thus a demand load that cannot be served as efficiently by baseload generation as would a flatter load profile. For example, Exhibit 3-4 depicts an example of a randomly chosen day of hourly demand differences from hour to hour in 2030 for the No RPS (GLP) case and the Full RPS (NLP) case (in the PJM system). Notice how the blue line (the No RPS case, is smoother and tends to have less extreme increases and decreases than the red line, which represents hourly changes in demand for the Full RPS case.

Exhibit 3-4. PJM Hourly Variability, 2030 Single Day Results

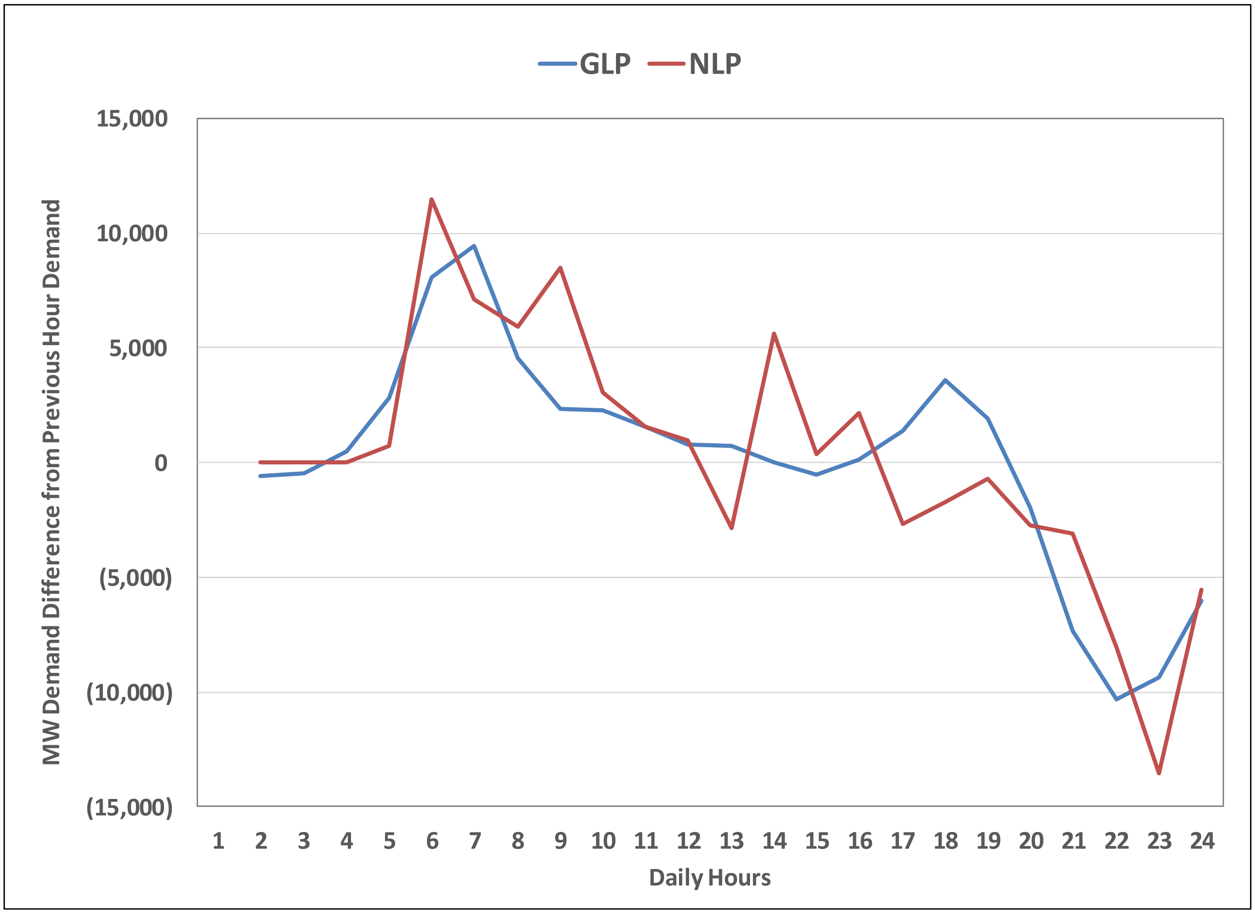
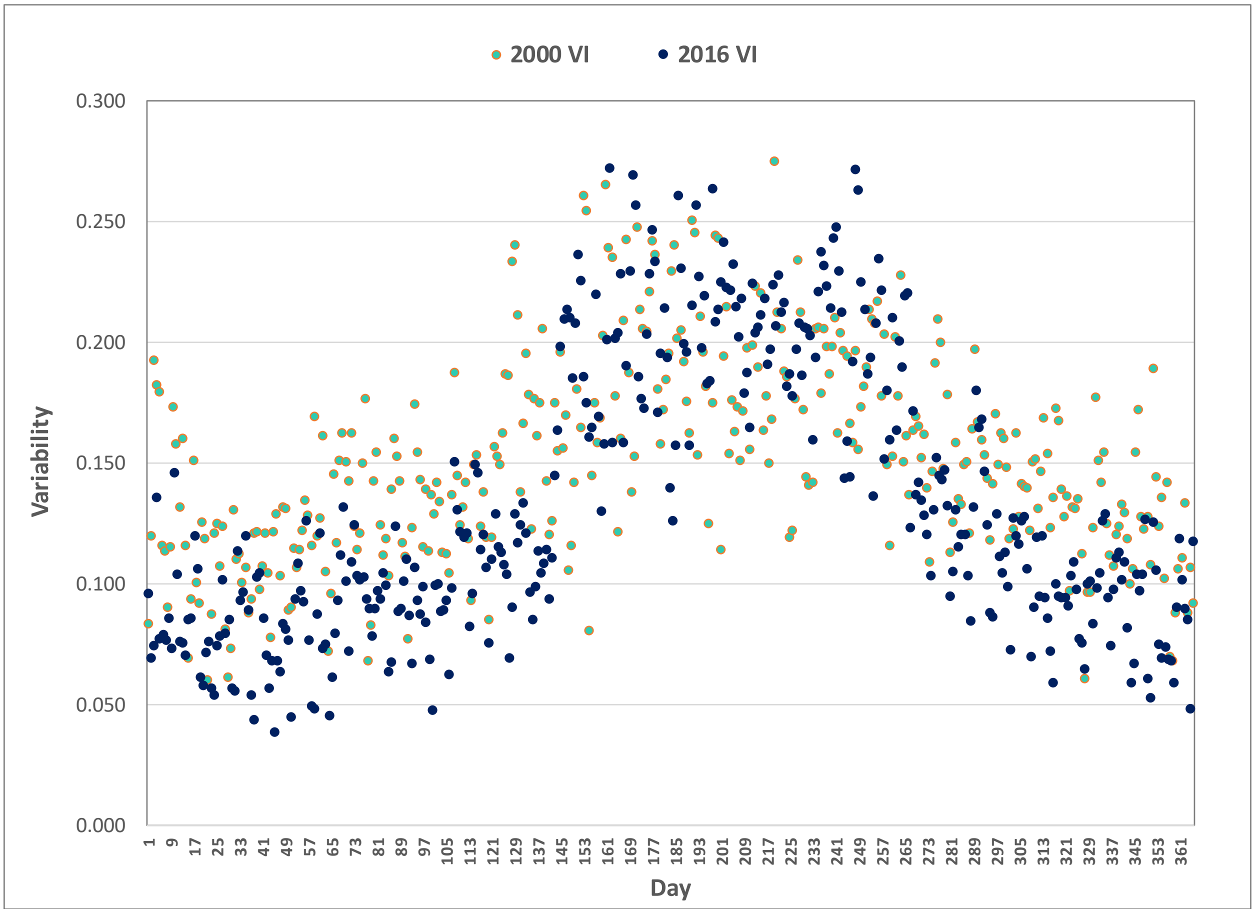


Exhibit 3-5 shows a comparison of the PJM 2000 daily LVI levels to the 2016 levels. There are several green data points (2016 demand) at higher levels in the beginning and end days of the year, which suggests that the winter days have more peaked daily demands in 2016 than 2000. The lower value 2016 LVI results compared with the 2000 LVI results in the summer months suggests that the daily demand profiles in the summer of 2016 were slightly flatter than the summer of 2000, which might be expected with a larger more diverse geographic area. Because of the physical changes in the PJM system from 2000 to 2016, the comparison is more on a concept basis than an "apples to apples" comparison.

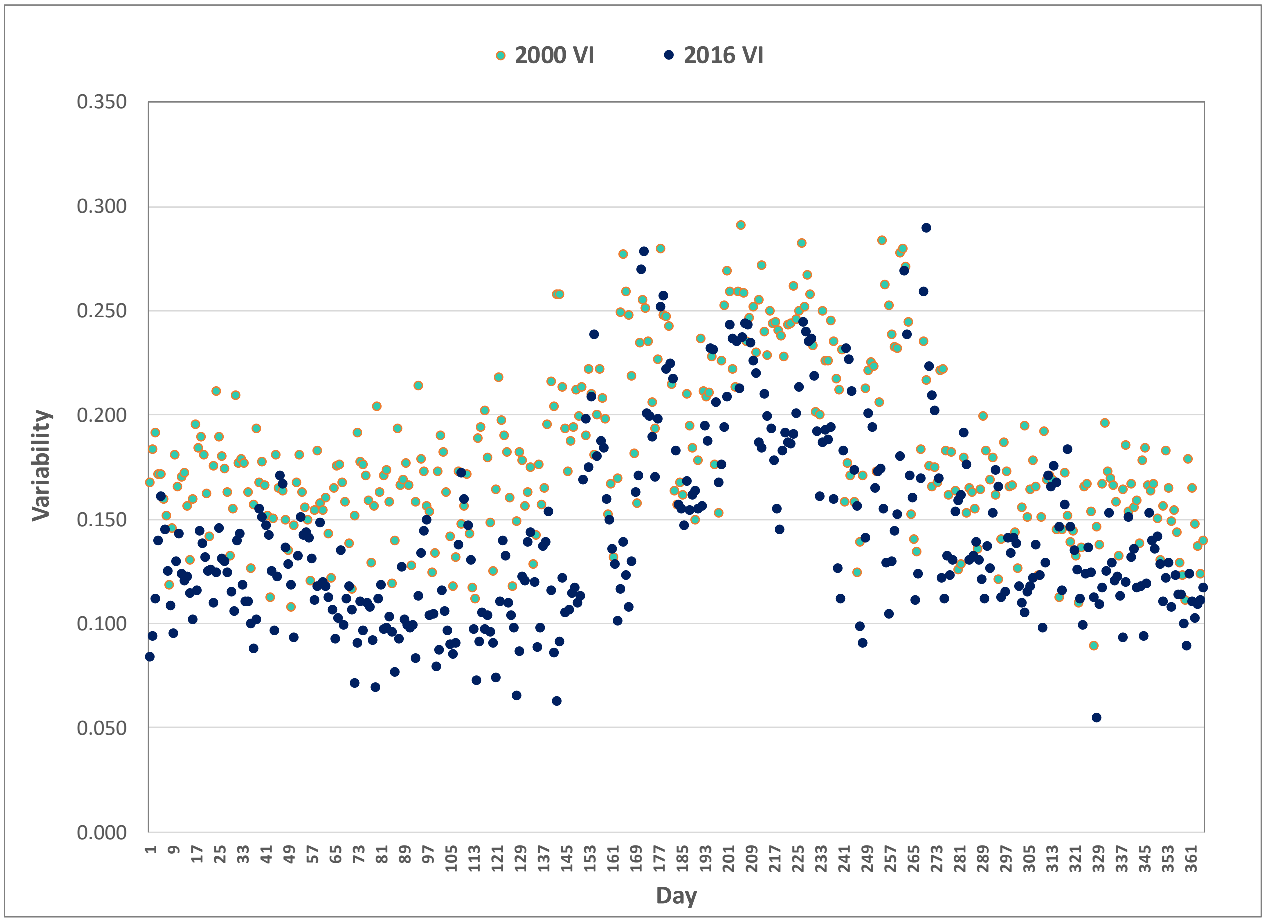
Exhibit 3-5. PJM Daily Variability, 2000 versus 2016



For comparison, the CAISO system was evaluated using LVI from 2000 to 2016; the comparison is shown in Exhibit 3-6. Note that the year 2016 LVI values (see dark blue dots) are lower than the year 2000 indicating slightly more peakedness in 2000. On a daily basis, this suggests less fluctuation in loads from day to day in 2016, possibly due to increased diversity.

The CAISO and the PJM systems are shown here since they represent the highest and lowest changes, respectively, that occurred out of all four systems when comparing RPS results in 2030. These results indicate the differences in load profiles have likely resulted from introducing few VRE (PJM) or significant amounts of VRE (CAISO). The LVIs for each system in 2016 and 2030 with and without RPS are discussed below.

Exhibit 3-6. CAISO Daily Load Variable Indices, 2000 versus 2016



LVI values based on daily net load are presented in Exhibit 3-7 and 3-8 for ERCOT, for 2016 historical data, and across scenarios (No RPS GLP, Full RPS NLP) for 2030. Similar results for CAISO are presented in Exhibits 3-9 and 3-10, MISO in Exhibits 3-11 and 3-12, and for PJM in Exhibits 3-13 and 3-14. Note that the future scenarios either include Full RPS goals met, or No RPS.

Exhibit 3-7. ERCOT Gross Daily Load Variable Indices, 2016 and 2030

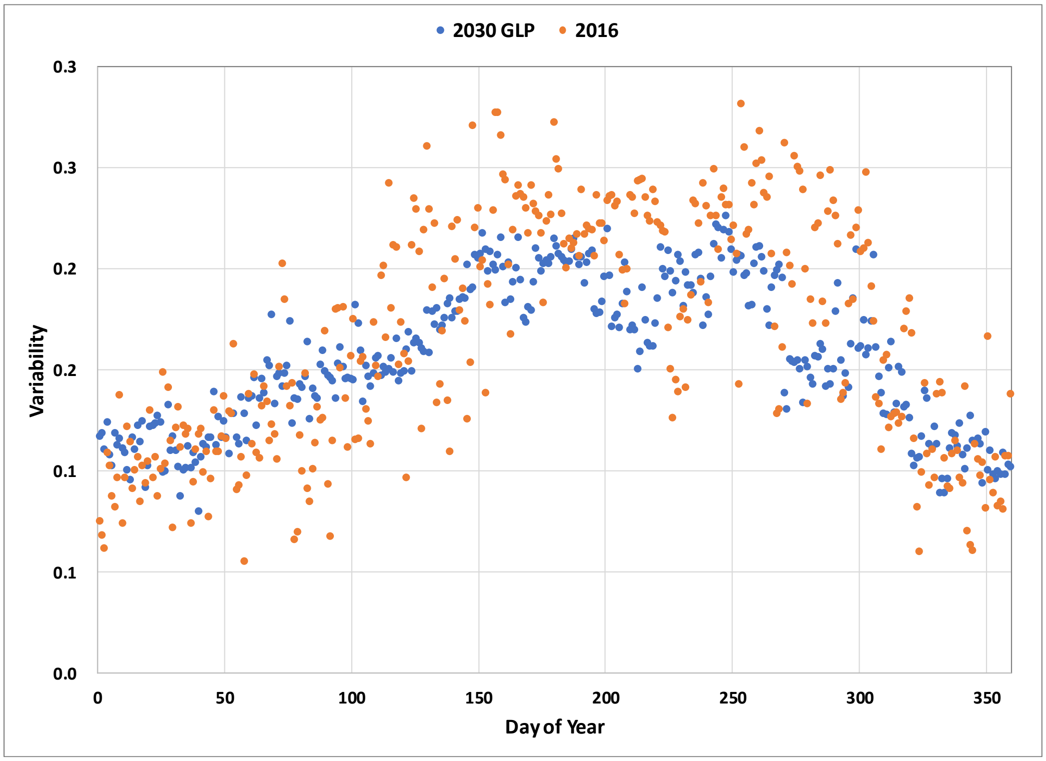


Exhibit 3-8. ERCOT Daily Load Variable Indices, 2030 GLP and 2030 NLP

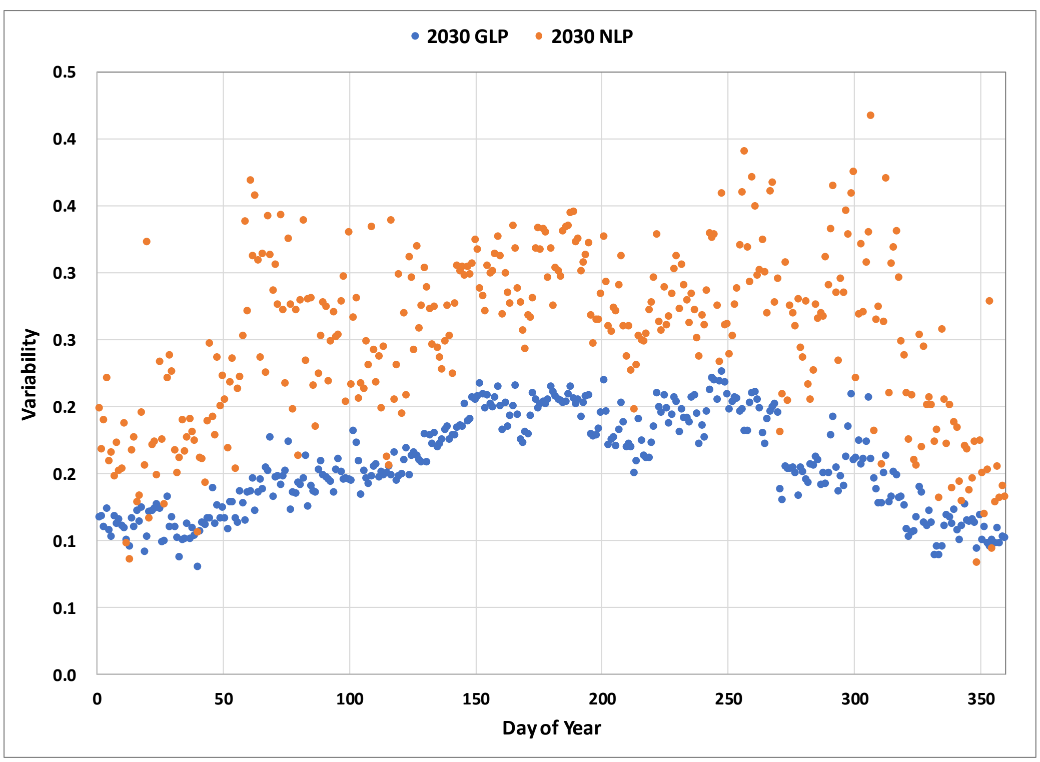


Exhibit 3-9. CAISO Gross Daily Load Variable Indices, 2016 and 2030

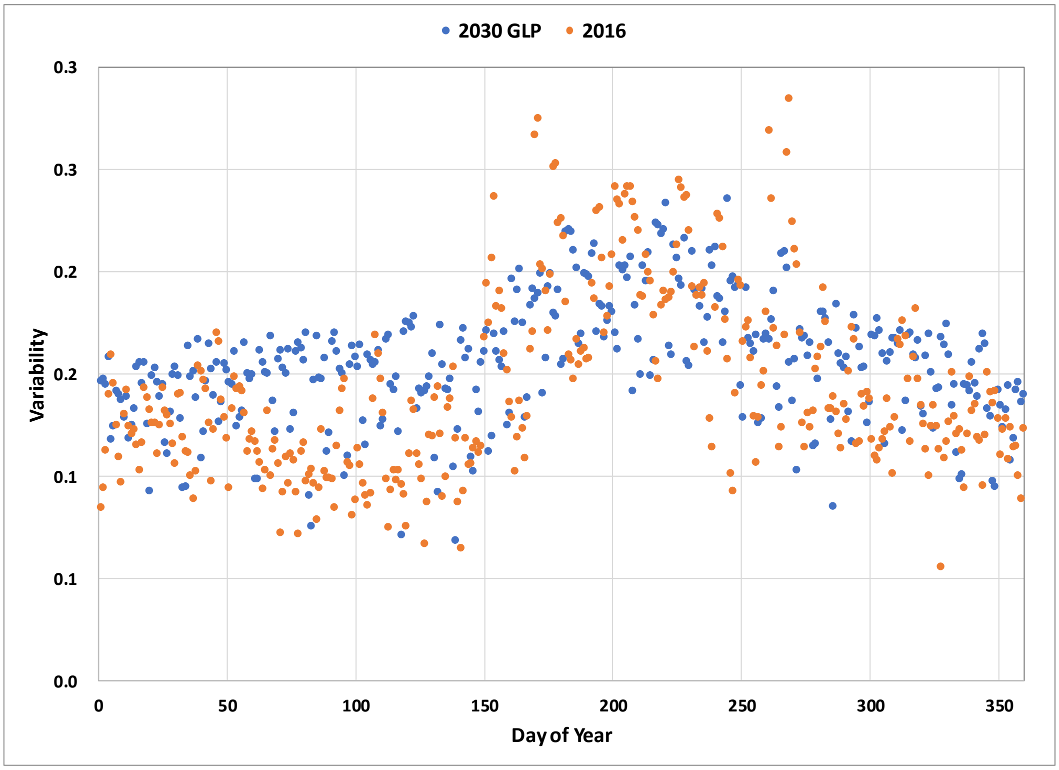


Exhibit 3-10. CAISO Daily Load Variability Indices, 2030 GLP and NLP

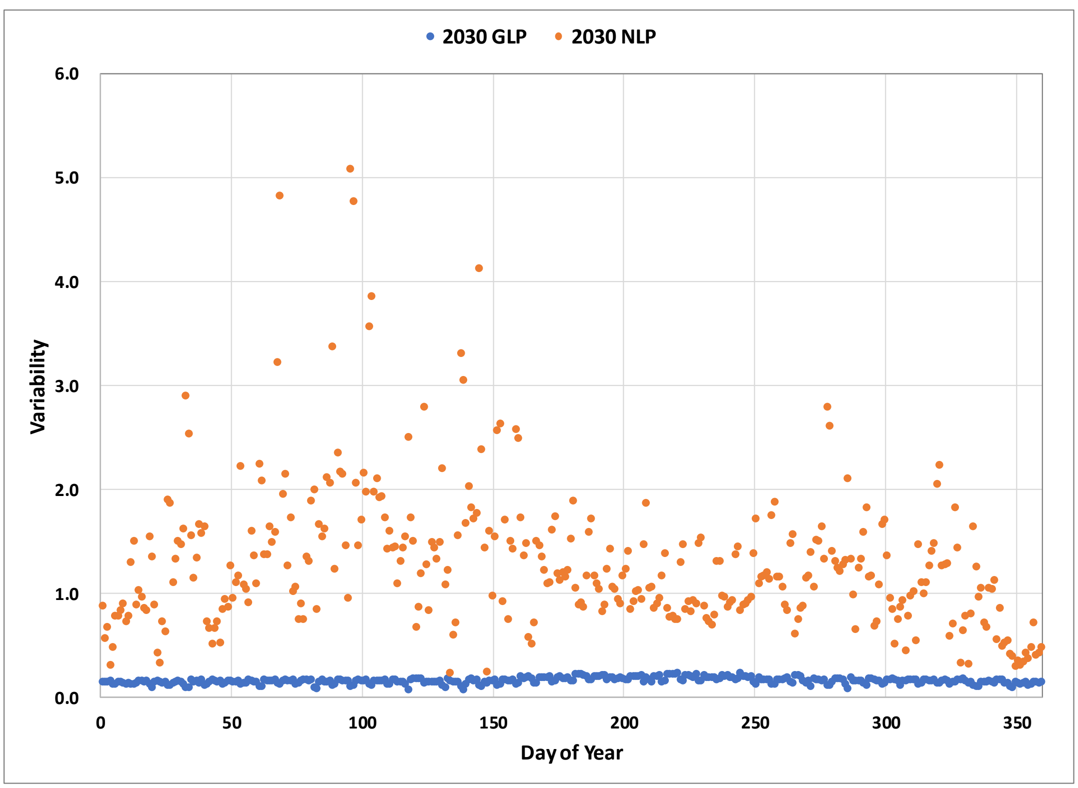


Exhibit 3-11. MISO Gross Daily Load Variable Indices, 2016 and 2030

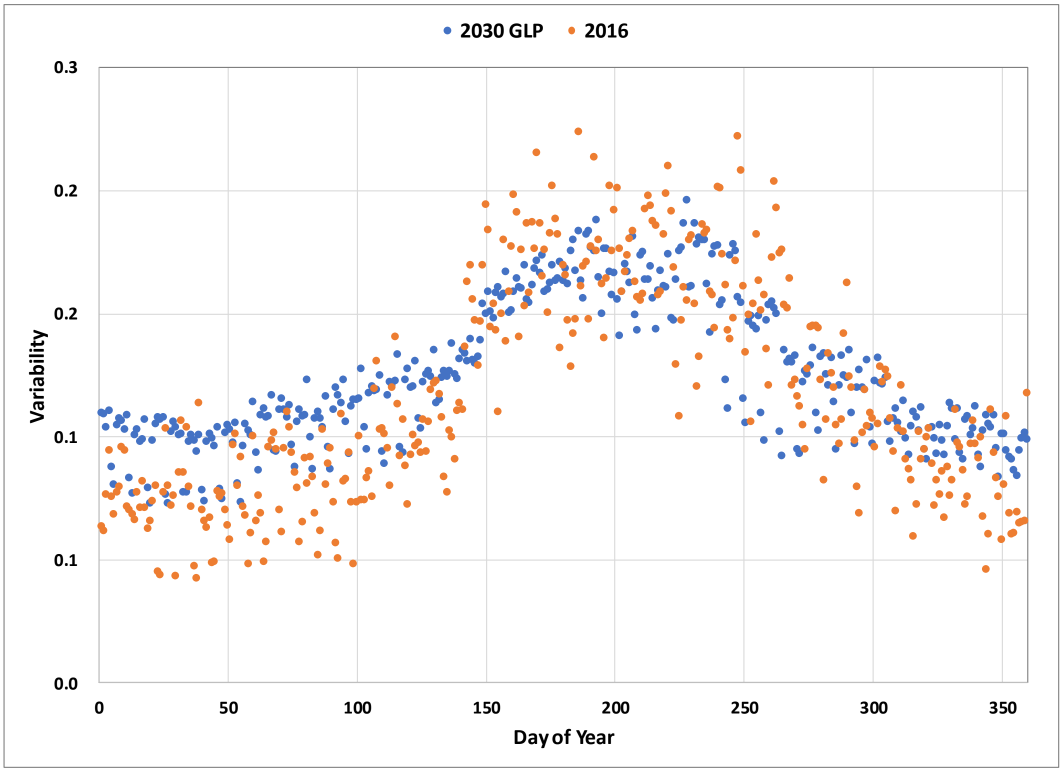


Exhibit 3-12. MISO Daily Load Variable Indices, 2030 GLP and NLP

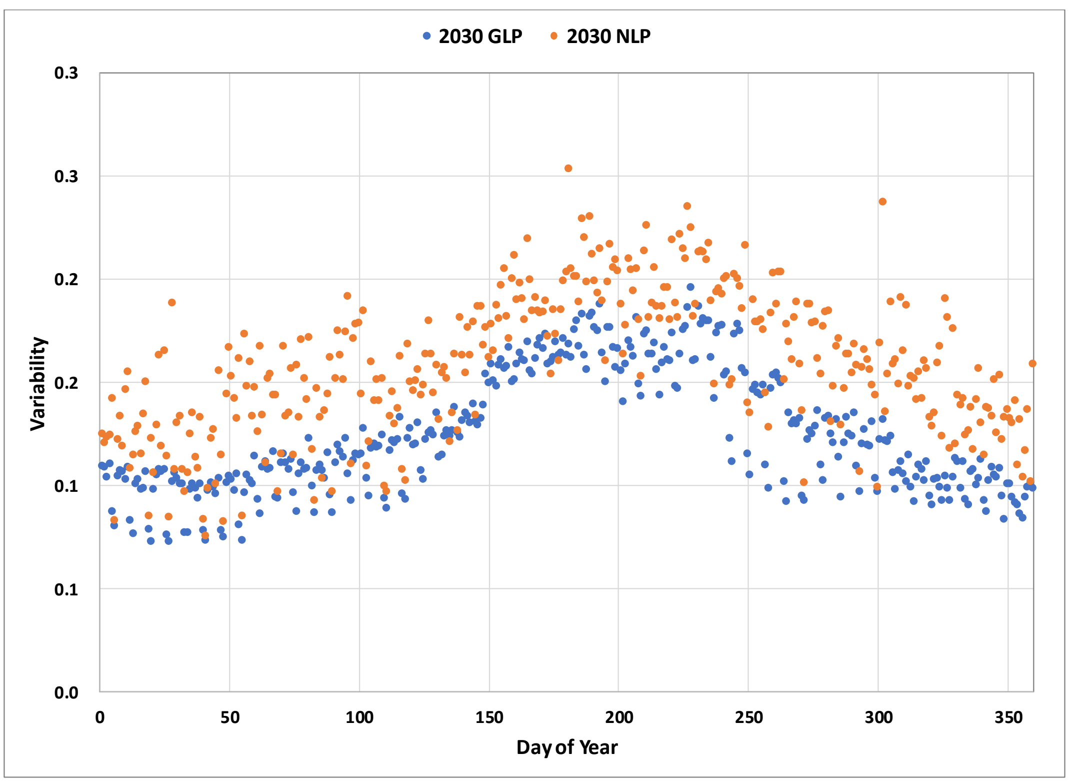


Exhibit 3-13. PJM Gross Daily Load Variable Indices, 2016 and 2030

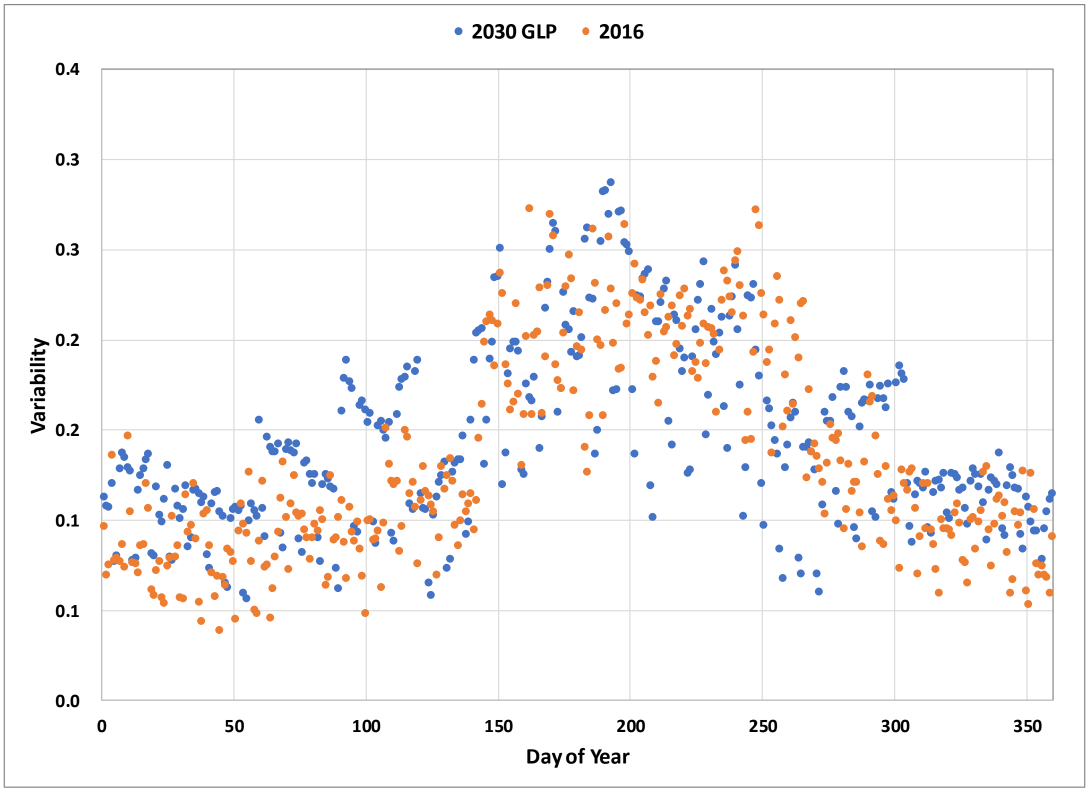
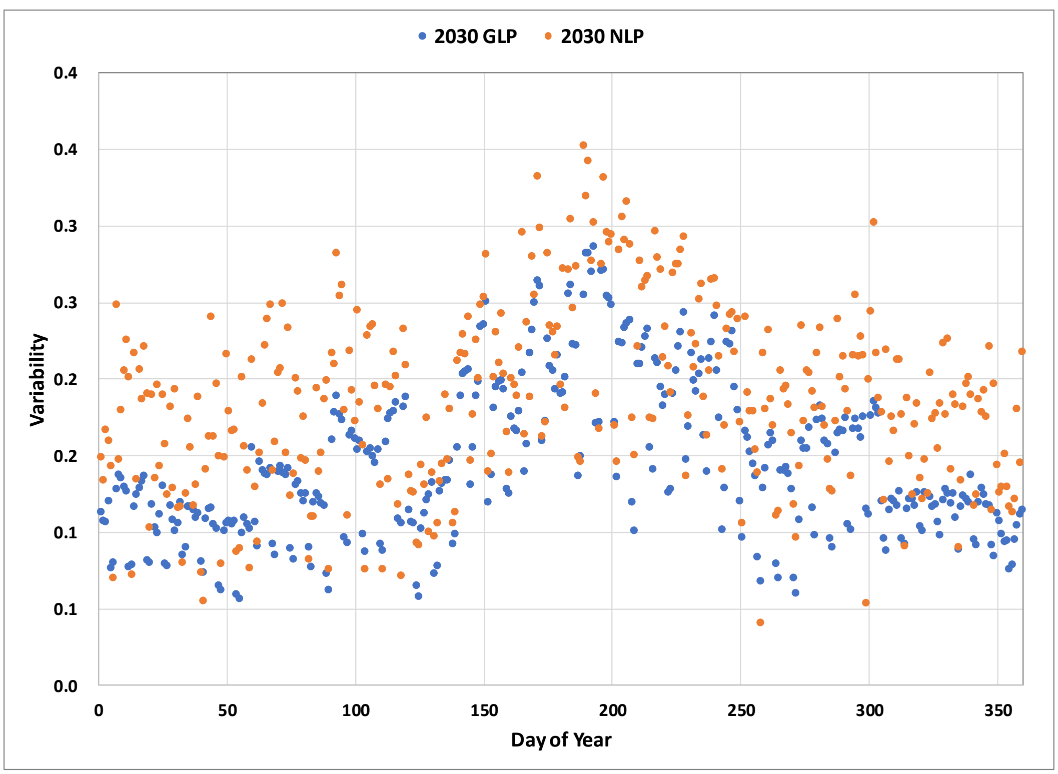


Exhibit 3-14. PJM Daily Load Variable Indices, 2030 GLP and NLP



In general, the daily LVI values for scenarios with No RPS are lower than the Full RPS scenarios. Assuming that the LVI developed here is a sound measure of the variability in net load, this implies that the net loads are typically less variable in scenarios with lower renewables penetration.

The largest difference between the Full RPS and No RPS scenarios' LVI values is seen in CAISO; this difference is especially emphasized in the summer months. This is likely due to the fact that there is a large difference in VRE penetration between the two scenarios, compared to the other ISOs (i.e., CAISO adds more renewables in the RPS scenarios, compared to the other ISOs), which exacerbates the difference in the LVI values of the net load.

In some ISOs (for example MISO), the mean daily LVI increases over the years. This is likely driven by the increasing renewables. In the scenarios with no future renewables additions, the daily LVI values are typically lower in the summer compared to the winter, indicating that the variability in net load is typically lower during this time. This may also be correlated with longer more persistent demand during this time.

3.3 Total System Cost Comparisons

The current convention for dispatching VRE generation is to assume it has a "zero energy cost." However, a case can be made that wind and solar are primarily energy resources due to the intermittency characteristic. Because it is assumed that most VRE are procured as energy only resources and therefore do not receive capacity payments, the cost comparison cases involved applying the levelized cost of electricity (LCOE) as a variable cost in ProMod™ to determine the annual system costs assuming VRE only recover energy revenue. This deposes the concept that because wind and sunshine are free, the energy they produce is also free, when it requires capital costs to capture the energy. Whereas, conventional resources are dispatched based on the cost of providing energy, which involves a cost of fuel, analogously, the cost of fuel for wind energy is the cost of erecting the wind turbine (plus delivering it to load), because there are typically very small or no capacity payments to recover those costs.

Admittedly, this approach to dispatching VRE would be a significant change in power system economic dispatch. However, it merely points to the need for resources to be dispatched according to the cost basis on which the energy is delivered. This approach therefore implies a pseudo-energy cost economic dispatch.

Several sources exist for the calculation of LCOE for VRE based on generator vintage. Two predominant sources are the IHS Rivalry model and the Lazard LCOE model [1,2,16]. These sources were compared to determine the best representative cost for renewables. Lazard provides a range of values for a given technology class but does not have technology specific information. Rivalry drills down to type of solar panel, for example, and provides cost projections by first year of operation and by region of the U.S. The Rivalry numbers fall within the ranges provided by Lazard. Due to the increased granularity of the Rivalry data, it was chosen to be the representative cost for renewables. Rivalry provides a single data table for wind generators, and several for solar photovoltaics (PV), including commercial, utility, and residential scale costs.

A cursory search of VRE in ProMod™ revealed the majority of the dispatchable solar to be utility-scale, ground mounted solar arrays. The two data tables from the Rivalry case were used to determine LCOE for each generator in the RTOs for this study. It was assumed that renewable generators, whether wind or solar, would have a 20-year life span and be replaced with the new year vintage. For example, a solar PV installation from 1998 would be retired in 2018 and replaced with the 2018 vintage solar PV. In the case of CAISO, several installations are 40+ years old. For these cases, a second life span was added if necessary. Production tax credits (PTCs) and investment tax credits (ITCs) were not included in the LCOE calculation. However, since the nature of the RPS related VRE is that they have often been installed to take advantage of tax subsidies and the improved efficiency, they are assumed to be replaced every 20 years to take advantage of the ITC and the greater efficiency. Applying the LCOE excluding the ITC and PTC was the chosen method of reflecting the full energy cost of VRE resulting from setting RPS goals.

Therefore, the LCOE for each VRE was used in the 2030 scenario as a variable O&M cost, which includes capital costs. This is consistent with the above logic of dispatching energy sources based on actual energy cost recovery needs. The new conventional generation was modeled with only fixed and variable costs included in the system energy costs.

For comparison of all-in costs, capital costs for all dispatchable generation less than 20 years old were calculated using capital recovery factors (CRFs), and added to the total energy cost for each scenario, the results of these calculations are shown in the following exhibits

- ERCOT total system cost (Exhibit 3-15)
- CAISO total system cost (Exhibit 3-16)
- MISO total system cost (Exhibit 3-17)
- PJM total system cost (Exhibit 3-18)

The only categories shown are those in which the costs changed. The Steam Energy Cost category includes the existing and new NGCCs and coal generation. Actual generation modeled is shown in the appendix resource schedules.

Exhibit 3-15. ERCOT Total System Annual Cost Comparisons

Cost Type	Full RPS Energy Only ($M)	No RPS Energy Only ($M)	Full RPS w/Capital Cost ($M)	No RPS w/Capital Cost ($M)
Purchase/Renewable Energy Cost*	$4,314	$6	$4,314	$6
Steam Energy Cost	$8,667	$11,002	$8,667	$11,002
Turbine Energy Cost	$220	$240	$220	$240
Added Capital Cost	-	-	$3,517	$4,418
Total	$13,201	$11,248	$16,718	$15,666

In Exhibit 3-15, high efficiency natural gas combined cycles (NGCC) and ultra-supercritical pulverized coal (USCPC) were added at the capital cost amounts shown in the appendix, escalated to the year of installation. Approximately 6.3 GW of USCPCs and 2.8 GW of NGCCs were added from 2021 to 2030 to meet the required reserve margins (see Section 2.5 and appendix). Combined with the fuel price assumptions in the AEO 2018 Reference Case [3], adding capital costs to the picture results in an approximate $1 billion less in costs for the No RPS case than having the Full RPS met in 2030.

Exhibit 3-16. CAISO Total System Cost Comparison

Cost Type	Full RPS Energy Only ($M)	No RPS Energy Only ($M)	Full RPS w/Capital Cost ($M)	No RPS w/Capital Cost ($M)
Emergency Energy Cost	$22	$1,594	$22	$1,594
Purchase/Renewable Energy Cost	$8,269	$18	$8,269	$18
Steam Energy Cost	$4,602	$8,960	$4,602	$8,960
Turbine Energy Cost	$576	$2,086	$576	$2,086
Added Capital Cost	-	-	$1,967	$3,722
Total	$13,469	$12,658	$15,436	$16,380

Exhibit 3-17. MISO Total System Cost Comparison

Cost Type	Full RPS Energy Only ($M)	No RPS Energy Only ($M)	Full RPS w/Capital Cost ($M)	No RPS w/Capital Cost ($M)
Emergency Energy Costs	685	1,865	685	1,865
Purchase/Renewable Energy Cost	$6,641	$23	$6,641	$23
Steam Energy Cost	$16,455	$18,619	$16,455	$18,938
Turbine Energy Cost	$592	$813	$592	$1,136
Added Capital Cost	-	-	$13,552	$14,677
Total	$24,373	$21,320	$37,925	$36,639

Exhibit 3-18. PJM Total System Cost Comparison

Cost Type	Full RPS Energy Only ($M)	No RPS High Tech Energy Only ($M)	Full RPS High-Tech w/Capital Cost ($M)	No RPS High Tech w/Capital Cost ($M)
Purchase/Renewable Energy Cost	$8,890	$30	$8,890	$30
Steam Energy Cost	$12,691	$16,945	$12,691	$16,945
Turbine Energy Cost	$84	$104	$84	$104
Added Capital Cost			$3,679	$4,075
Total	$21,665	$17,079	$25,344	$21,154

These results show a higher system cost increase whether "Energy Only" costs or "Capital Cost" cases are considered. In CAISO and ERCOT, smaller systems with large renewable presences, the difference in costs with and without RPS is about $2 billion annually for each system; whereas, PJM and MISO have about $4.5 and $5 billion, respectively.

Expanding the analysis to include added capital costs for generators less than 20 years old, shows that the Full RPS case is a higher cost than the scenario using the best available technology, despite the higher cost of those technologies, except for in CAISO which is largely due to the declining cost assumptions for such a large amount of renewables in contrast with increasing costs for conventional generation used to replace renewables in the No RPS case. The results of this analysis depend heavily on the overnight costs used to calculate the added capital costs. Those used in this study were sourced from the EIA AEO 2016, and are in the Appendix.

Again, transmission costs and backup sources are not included in the Full RPS case, so there is a need to do a more detailed accounting of costs beyond what is shown here.

4 SUMMARY

The objective of this study was to answer the question: "would targeting a level demand profile and high baseload generation result in more efficient power systems?"

The measure used for efficiency is the COE, and the LCOE for renewable energy and new conventional generation was used to estimate the total annual costs in 2030 for power in the CAISO, MISO, PJM, and ERCOT power systems. Power system costs were estimated for two cases: 1) the systems as operated with the currently planned state RPS targets, and 2) the systems with No RPS targets, and thus no VRE as sought under state RPS programs. The system costs were obtained using ProMod™ to simulate the power systems using data provided by PJM and ABB.

In order to assess the degree to which adding VRE to meet RPS goals affected the level of variability in each system, two approaches were used. A new load variability index was used to measure daily variability, the LVI, and SLFs were used for assessing annual and quarterly variability. Both statistics showed that the NLP that remains when VRE are subtracted is less flat than the GLP that comprises the basic loads with no VRE. The NLP and GLP for each system was obtained from the ProMod™ model, which simulates the economic dispatch of all system generation after applying the solar and wind supply profiles, which were obtained from the NREL database of wind and solar supply profiles.

In all four RTOs, the annual system costs with VRE as stipulated by state RPS policies is estimated to be higher than the system costs with No RPS policies in place. This is generally consistent with results from a report completed by Trieu, et al. [17], although externalities were added in that study not included here.

Exhibit 4-1 shows the reduction in costs as found in the No RPS cases in 2030.

Exhibit 4-1. Study results summary

ISO/RTO	Foregone EBCL (GW)	Annual Benefits (Costs) of RPS (Millions $)
CAISO	13	**($811)**
ERCOT	14	**($1,953)**
MISO	18	**($3,053)**
PJM	16	**($4,580)**
Total	**61**	**($10,397)**

Another measure derived in this analysis is EBCL, which is defined as the minimum average 30-day demand divided by the expected capacity factor of baseload generation. For this study, an 85 percent capacity factor was used to obtain the EBCL in cases with and without RPS, and it was found that more level load demand can be served more efficiently by baseload generation because of the higher efficiency achieved when baseload generators operate continuously at a high capacity factor. Exhibit 4-1 summarizes the amount of EBCL circumvented due to the state

RPS resulting in a more volatile load, and the annual costs of not having that higher EBCL. These cost results are based on declining VRE resource costs through 2030, whereas dispatchable generation costs are assumed to be increasing.

Based on these results, it does appear that targeting a more level load, perhaps balancing VRE more with demand management efforts would lead to lower costs and a more efficient power system. Since CAISO and ERCOT have already met the RPS targets, there is little that can be done other than to develop a reimbursement to the system for imposing higher operational costs. The MISO and PJM RTOs could attempt to do the same, and by modifying the economic dispatch to be based on how generation costs require reimbursement of costs.

Variability measurements such as those used in this study could possibly be used to apply a cost for imposing variability in a power system when creating higher cost electricity supply conditions. This payment system could be designed by using the native, or GLP, as a starting point for measuring the efficiency of serving demand as efficiently as possible from a system approach rather than a single resource approach. Integrated resource planning applies this concept in planning, and given today's technology, it would seem possible to apply it in the economic dispatch algorithms used by RTOs.

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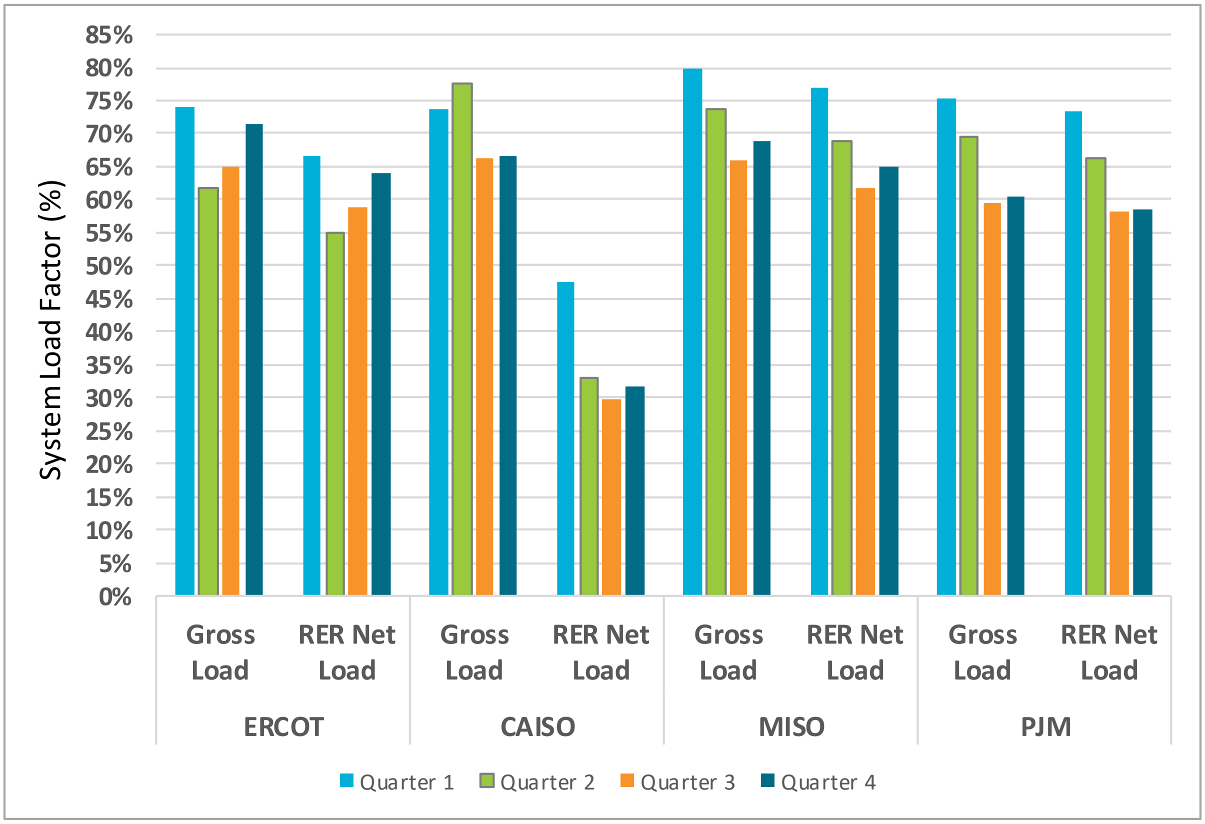
APPENDIX: ADDITIONAL ANALYSES

QUARTERLY SYSTEM LOAD FACTORS

Quarterly system load factors for the regions are shown in Exhibit A-1. The California Independent System Operator (CAISO) region has the largest percentage of renewables as installed capacity compared to all the regions in this study. The high VRE level in CAISO is reflected in the large percentage difference between the gross load and the net load case. This shows a much flatter load shape before renewable generation has been subtracted from the load, versus the full load. Note the small differences in the quarterly system load factors (SLFs) shown for the other regions. Also note that because of the use of quarterly peak demand and energy, the quarterly SLFs are higher than the annual SLFs in all systems.

Exhibit A-1. Quarterly SLF by region, gross and net loads (2030)



COEFFICIENT OF VARIATION

Another metric that measures variability, similar to SLFs, is the coefficient of variation (CoV), defined as the standard distribution of the sample data, normalized to the mean. Lower values of CoV indicate less variability around the average daily demand levels. The simple formula is:

$$\mathrm{CoV} = \frac{\sigma}{\mu}$$

where:

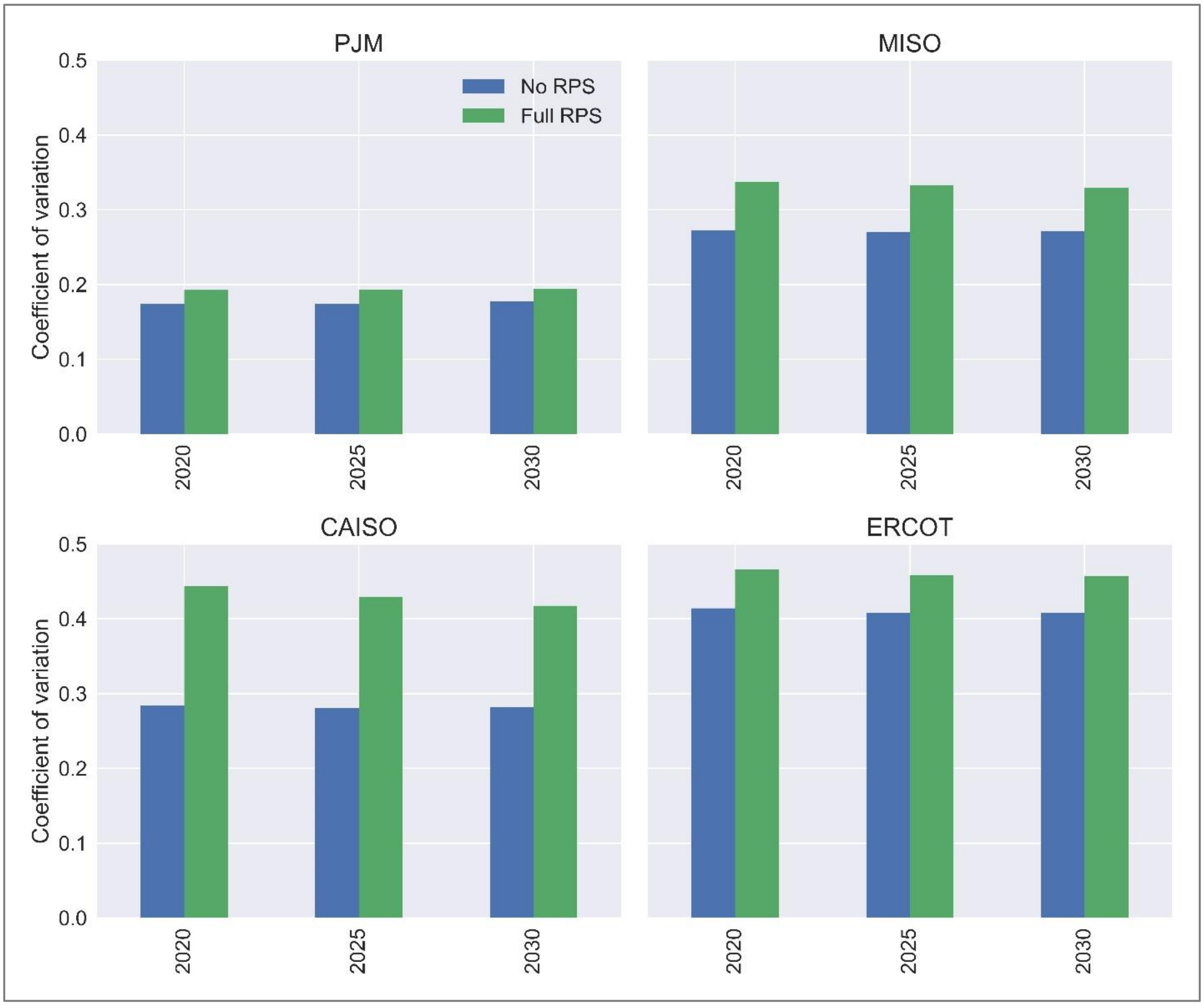
σ = the standard deviation

μ = the mean

Annual CoV values of net load for all ISOs/RTOs across different scenarios and over time are presented in Exhibit A-2.

Exhibit A-2. CoV of Net Load for all ISOs, All Scenarios

(No RPS, Full RPS) for different simulation years (2020, 2025, 2030).



From these results, it appears that PJM Interconnection (PJM) has the lowest variability in net load, while Electric Reliability Council of Texas (ERCOT) has the highest (which is determined by variability in gross load as well as renewables penetration). In general, the CoV of net load in scenarios with no renewable portfolio standards (RPS) are lower than the Full RPS scenarios. Assuming that CoV is one measurement of the variability in net load, this implies that the net loads are typically less variable in scenarios with lower renewables penetration (consistent with findings in the kurtosis results).

The largest difference between the Full RPS and No RPS scenario CoV values is seen in CAISO, likely due to the fact that there is a large difference in renewables penetration between the two scenarios, compared to the other ISOs/RTOs (i.e., CAISO adds more renewables in the RPS scenarios, compared to the other ISOs).

CAPITAL COST ACCOUNTING

The resource schedule for each region are in Capital costs calculations for generator units less than 20 years old were calculated using a CRF equation. Only the capital costs were added to the energy costs from ProMod™ as shown in the summary tables in the report. In other words, the levelized cost of capital was used.

The levelization formula for capital costs is:

$$\text{CRF} = \frac{WACC\ x\ (1+WACC)^{y}}{(1+WACC)^{y}-1}$$

where:

y = years of expected operation (coal 30, gas 20)

CRF = Capital recovery factor

WACC = nominal weighted average cost of capital

Exhibit A-3. ERCOT Resource Schedule Capital costs calculations for generator units less than 20 years old were calculated using a CRF equation. Only the capital costs were added to the energy costs from ProMod™ as shown in the summary tables in the report. In other words, the levelized cost of capital was used.

The levelization formula for capital costs is:

$$\text{CRF} = \frac{WACC\ x\ (1+WACC)^{y}}{(1+WACC)^{y}-1}$$

where:

y = years of expected operation (coal 30, gas 20)

CRF = Capital recovery factor

WACC = nominal weighted average cost of capital

Exhibit A-3 through Exhibit A-6. The category names in these tables use the values from the model. Internal Combustion (IC), Steam Turbine (ST), Combustion Turbine (CT), as well as "(Planned)" and "(Existing)" are being used to denote separate unit categories in the model. In the case of the No RPS models, the natural gas combined cycles and coal units were assumed to be high efficiency as expected by 2030; other generation was assumed replaced with the same technology.

Capital costs calculations for generator units less than 20 years old were calculated using a CRF equation. Only the capital costs were added to the energy costs from ProMod™ as shown in the summary tables in the report. In other words, the levelized cost of capital was used.

The levelization formula for capital costs is:

$$\text{CRF} = \frac{WACC\ x\ (1 + WACC)^{y}}{(1 + WACC)^{y} - 1}$$

where:

y = years of expected operation (coal 30, gas 20)

CRF = Capital recovery factor

WACC = nominal weighted average cost of capital

Exhibit A-3. ERCOT Resource Schedules – MWs Added

ERCOT No RPS Resource Schedule																							
Technology	**1**	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Combined Cycle (Existing)	2	1,363	611	-	-	1,979	694	-	2,650	1,647	-	230	-	-	-	-	-	-	-	-	-	-	9,173
Combined Cycle (Planned)	3	-	-	-	-	-	-	-	230	133	50	694	675	-	-	1,008	636	-	-	-	468	-	3,894
Conventional Hydro	4	-	-	-	-	-	24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24
CT Gas	5	369	34	-	88	-	373	667	699	230	-	-	-	-	-	-	-	-	-	-	-	-	2,461
CT Other	6	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11
IC Gas	7	203	-	-	-	-	-	271	-	-	-	-	-	-	-	-	-	-	-	-	-	-	474
IC Oil	8	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1
IC Renewable	9	12	6	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23
ST Coal	10	1,593	286	-	970	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,849
ST Coal (Planned)	11	-	-	-	-	-	-	-	-	-	706	-	-	706	706	706	706	706	706	706	1,412	-	7,060
ST Gas	12	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11
ST Renewable	13	-	44	105	-	15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	164
Total	15	3,540	994	105	1,058	2,008	1,091	938	3,579	2,010	756	924	675	706	706	1,714	1,342	706	706	706	1,880	-	26,144

ERCOT Full RPS Resource Schedule																							
Technology	1	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Combined Cycle (Existing)	2	1,363	611	-	-	1,979	694	-	2,650	1,647	-	230	-	-	-	-	-	-	-	-	-	-	9,173
Combined Cycle (Planned)	3	-	-	-	-	-	-	-	230	1,048	50	694	675	-	243	1,008	636	225	-	-	-	-	4,809
Conventional Hydro	4	-	-	-	-	-	24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24
CT Gas	5	369	34	-	88	-	373	667	699	230	-	-	-	-	-	-	-	-	-	-	-	-	2,461
CT Gas (Planned)	6	-	-	-	-	-	-	-	465	232	-	-	-	-	-	-	-	-	-	-	-	-	697
CT Other	7	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11
IC Gas	8	203	-	-	-	-	-	271	-	-	-	-	-	-	-	-	-	-	-	-	-	-	474
IC Oil	9	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1
IC Renewable	10	12	6	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23
Solar PV	11	14	33	30	51	124	106	562	314	300	-	182	-	-	115	-	115	115	-	115	115	-	2,289
ST Coal	12	1,593	286	-	970	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,849
ST Coal (Planned)	13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	706	-	706	-	706	-	-	2,118
ST Gas	14	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11
ST Renewable	15	-	44	105	-	15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	164
Wind	16	150	225	1,439	753	1,529	2,924	2,795	597	1,783	889	230	-	-	-	-	-	-	-	-	-	-	13,313
Wind (Planned)	17	-	-	-	-	-	-	1,288	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,288
Total	18	3,704	1,252	1,574	1,861	3,662	4,121	5,582	4,954	5,239	939	1,336	675	-	358	1,714	751	1,046	-	821	115	-	39,704

Exhibit A-4 CAISO Resource Schedules – MWs Added

CAISO No RPS - Resource Schedule

Technology	**1**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Total**
Combined Cycle (Existing)	2	1,032	-	813	1,431	-	-	377	-	624	-	-	-	-	-	-	-	-	-	-	-	-	4,277
Combined Cycle (Planned)	3	-	-	-	-	-	-	-	-	-	-	7,434	1,515	1,515	1,515	1,515	1,515	1,515	1,515	1,515	1,515	1,515	22,582
Conventional Hydro	4	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	4
CT Gas	5	161	294	483	2,640	50	-	509	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,136
CT Renewable	6	7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7
Fuel Cell	7	-	1	4	5	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12
Fuel Cell (Planned)	8	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4
IC Gas	9	167	49	-	4	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	222
IC Oil	10	-	33	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	33
IC Other	11	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5
IC Renewable	12	11	11	-	9	38	-	32	-	-	-	-	-	-	-	-	-	-	-	-	-	-	101
IC Renewable (Planned)	13	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6
Pumped Storage Hydro	14	-	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21
ST Gas	15	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4
ST Renewable	16	-	-	18	-	-	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38
ST Renewable (Planned)	17	-	-	-	-	-	-	34	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34
Total		1,382	410	1,323	4,088	90	21	961	-	628	-	7,434	1,515	1,515	1,515	1,515	1,515	1,515	1,515	1,515	1,515	1,515	**31,485**

CAISO Full RPS - ResourceSchedule

Technology	**1**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Total**
Combined Cycle (Existing)	2	1,032	-	813	1,431	-	-	377	-	624	-	-	-	-	-	-	-	-	-	-	-	-	4,277
Combined Cycle (Planned)	3	-	-	-	-	-	-	-	-	-	-	7,434	-	-	-	-	-	-	-	-	2,073	-	9,507
Conventional Hydro	4	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	4
CT Gas	5	161	294	483	2,640	50	-	509	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,136
CT Renewable	6	7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7
Fuel Cell	7	-	1	4	5	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12
Fuel Cell (Planned)	8	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4
Geothermal	9	25	-	53	-	-	-	23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	101
Geothermal (Planned)	10	-	-	-	-	-	-	74	33	-	42	50	-	-	-	-	-	-	-	-	-	-	199
IC Gas	11	167	49	-	4	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	222
IC Oil	12	-	33	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	33
IC Other	13	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5
IC Renewable	14	11	11	-	9	38	-	32	-	-	-	-	-	-	-	-	-	-	-	-	-	-	101
IC Renewable (Planned)	15	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6
Pumped Storage Hydro	16	-	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21
Solar	17	-	-	-	-	-	-	19	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19
Solar PV	18	54	272	753	2,786	1,236	816	1,704	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7,619
Solar PV (Planned)	19	-	-	-	-	-	-	3,351	2,448	641	4,803	14,890	200	200	200	200	200	200	200	-	-	-	27,533
Solar Steam	20	-	30	-	642	286	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	958
Solar Steam (Planned)	21	-	-	-	-	-	-	646	450	-	-	-	-	-	-	-	-	-	-	-	-	-	1,096
ST Gas	22	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4
ST Renewable	23	-	-	18	-	-	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38
ST Renewable (Planned)	24	-	-	-	-	-	-	34	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34
Wind	25	1,652	362	925	-	1	365	152	88	-	-	-	-	-	-	-	-	-	-	-	-	-	3,545
Wind (Planned)	26	-	-	-	-	-	-	777	661	14	175	-	175	-	500	-	-	-	-	-	-	1,619	3,921
Total		**3,113**	**1,073**	**3,053**	**7,516**	**1,613**	**1,203**	**7,707**	**3,680**	**1,283**	**5,020**	**22,374**	**375**	**200**	**700**	**200**	**200**	**200**	**200**	**-**	**2,073**	**1,619**	**63,401**

Exhibit A-5 MISO Resource Schedules – MWs Added

MISO No RPS - Resource Schedule																							
Technology	**1**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Total**
Combined Cycle (Existing)	2	-	137	143	100	587	-	229	1,301	644	980	-	-	-	-	-	-	-	-	-	-	-	4,120
Combined Cycle (Planned)	3	-	-	-	-	-	-	-	-	-	1,907	1,907	1,907	1,907	1,907	1,907	1,907	1,907	1,907	1,907	1,907	1,907	22,884
Conventional Hydro	4	-	10	-	-	-	164	-	-	41	-	-	-	-	-	-	-	-	-	-	-	-	215
CT Gas	5	124	294	-	-	178	41	441	-	8	-	-	-	-	-	-	-	-	-	-	-	-	1,085
CT Renewable	6	13	-	-	27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40
IC Gas	7	3	17	-	-	-	-	77	-	-	165	-	-	-	-	-	-	-	-	-	-	-	262
IC Oil	8	17	82	24	25	9	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	158
IC Renewable	9	5	16	27	21	7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	76
IGCC (Existing)	10	-	-	-	618	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	618
Nuclear (Planned)	11	-	-	-	-	-	-	-	1,500	-	-	-	-	-	-	-	-	-	-	-	-	-	1,500
ST Coal	12	1,823	615	1,629	-	52	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,119
ST Coal (Planned)	13	-	-	-	-	-	-	-	-	-	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	23,326
ST Gas	14	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4
ST Other	15	78	-	-	28	1	-	15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	122
ST Renewable	16	-	19	35	60	47	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200
Total		2,062	1,188	1,859	879	885	246	762	2,801	693	4,996	3,851	3,851	3,851	3,851	3,851	3,851	3,851	3,851	3,851	3,851	3,851	58,730

MISO Full RPS - Resource Schedule																							
Technology	**1**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Total**
Combined Cycle (Existing)	2	-	137	143	100	587	-	229	1,301	644	980	-	-	-	-	-	-	-	-	-	-	-	4,120
Combined Cycle (Planned)	3	-	-	-	-	-	-	-	-	-	1,921	-	1,921	1,921	1,921	1,921	1,921	1,921	1,921	1,921	1,921	-	19,208
Conventional Hydro	4	-	10	-	-	-	164	-	-	41	-	-	-	-	-	-	-	-	-	-	-	-	215
CT Gas	5	124	294	-	-	178	41	441	-	8	-	-	-	-	-	-	-	-	-	-	-	-	1,085
CT Renewable	6	13	-	-	27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40
Geothermal	7	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6
IC Gas	8	3	17	-	-	-	-	77	-	-	165	-	-	-	-	-	-	-	-	-	-	-	262
IC Oil	9	17	82	24	25	9	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	158
IC Renewable	10	5	16	27	21	7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	76
IGCC (Existing)	11	-	-	-	618	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	618
Nuclear (Planned)	12	-	-	-	-	-	-	-	1,500	-	-	-	-	-	-	-	-	-	-	-	-	-	1,500
Solar PV	13	-	1	11	48	55	35	2	-	34	-	-	-	-	-	-	-	-	-	-	-	-	186
Solar PV (Planned)	14	-	-	-	-	-	-	175	20	-	146	-	146	146	146	146	146	146	146	146	146	146	1,797
ST Coal	15	1,823	615	1,629	-	52	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,119
ST Coal (Planned)	16	-	-	-	-	-	-	-	-	1,993	1,993	-	1,993	1,993	1,993	1,993	1,993	1,993	1,993	1,993	1,993	-	21,928
ST Gas	17	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4
ST Other	18	78	-	-	28	1	-	15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	122
ST Renewable	19	-	19	35	60	47	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200
Wind	20	1,122	1,800	2,308	207	886	576	153	538	823	2,187	-	-	-	-	-	-	-	-	225	-	-	10,825
Wind (Planned)	21	-	-	-	-	-	-	3,917	375	552	-	-	4,453	500	3,642	500	7,000	5,496	2,500	-	-	-	28,935
TOTAL		3,190	2,989	4,177	1,134	1,826	857	5,009	3,734	4,096	7,392	-	8,513	4,560	7,702	4,560	11,060	9,556	6,560	4,285	4,060	146	95,404

Exhibit A-6 PJM Resource Schedules – MWs Added

PJM No RPS - Resource Schedule

Technology	**1**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Total**
Combined Cycle (Existing)	**2**	-	2,014	570	59	2,136	1,614	3,609	2,992	2,233	-	-	-	-	-	-	-	-	-	-	-	-	15,226
Combined Cycle (Planned)	**3**	-	-	-	-	-	-	691	830	3,699	6,758	-	-	-	-	-	-	-	-	-	-	-	11,978
Conventional Hydro	**4**	-	-	-	-	-	177	23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	199
CT Gas	**5**	152	12	406	-	-	335	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	904
CT Gas (Planned)	**6**	-	-	-	-	-	-	200	577	233	-	97	-	-	-	-	-	-	-	-	-	-	1,107
CT Renewable	**7**	2	10	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19
Fuel Cell	**8**	-	-	3	24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	27
IC Gas	**9**	-	-	-	-	-	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21
IC Gas (Planned)	**10**	-	-	-	-	-	-	6	80	40	-	-	-	-	-	-	-	-	-	-	-	-	125
IC Oil	**11**	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2
IC Renewable	**12**	9	22	13	23	-	25	29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	121
IC Renewable (Planned)	**13**	-	-	-	-	-	-	36	3	5	-	-	-	-	-	-	-	-	-	-	-	-	44
ST Coal	**14**	-	-	1,326	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,336
ST Gas	**15**	-	-	-	-	-	262	2,776	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,038
ST Other	**16**	-	51	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	51
ST Renewable	**17**	30	-	-	47	-	238	63	-	-	-	-	-	-	-	-	-	-	-	-	-	-	378
ST Renewable (Planned)	**18**	-	-	-	-	-	-	-	-	80	-	-	-	-	-	-	-	-	-	-	-	-	80
Total		193	2,108	2,328	153	2,136	2,681	7,432	4,481	6,290	6,758	97	-	-	-	-	-	-	-	-	-	-	34,656

PJM Full RPS - Resource Schedule

Technology	**1**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Total**
Combined Cycle (Existing)	**2**	-	2,014	570	59	2,136	1,614	3,609	2,992	2,233	-	-	-	-	-	-	-	-	-	-	-	-	15,226
Combined Cycle (Planned)	**3**	-	-	-	-	-	-	691	830	3,222	3,385	-	-	-	-	-	-	-	-	-	-	-	8,128
Conventional Hydro	**4**	-	-	-	-	-	177	23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	199
CT Gas	**5**	152	12	406	-	-	335	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	904
CT Gas (Planned)	**6**	-	-	-	-	-	-	200	577	233	-	97	-	-	-	-	-	-	-	-	-	-	1,107
CT Renewable	**7**	2	10	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19
Fuel Cell	**8**	-	-	3	24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	27
IC Gas	**9**	-	-	-	-	-	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21
IC Gas (Planned)	**10**	-	-	-	-	-	-	6	80	40	-	-	-	-	-	-	-	-	-	-	-	-	125
IC Oil	**11**	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2
IC Renewable	**12**	9	22	13	23	-	25	29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	121
IC Renewable (Planned)	**13**	-	-	-	-	-	-	36	3	5	-	-	-	-	-	-	-	-	-	-	-	-	44
Solar PV	**14**	8	107	97	19	64	200	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	496
Solar PV (Planned)	**15**	-	-	-	-	-	23	927	273	523	246	-	-	-	-	-	-	-	-	-	-	-	1,993
ST Coal	**16**	-	-	1,326	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,336
ST Gas	**17**	-	-	-	-	-	262	2,776	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,038
ST Other	**18**	-	51	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	51
ST Renewable	**19**	30	-	-	47	-	238	63	-	-	-	-	-	-	-	-	-	-	-	-	-	-	378
ST Renewable (Planned)	**20**	-	-	-	-	-	-	-	-	80	-	-	-	-	-	-	-	-	-	-	-	-	80
Wind	**21**	401	975	1,170	-	240	255	-	250	-	-	-	-	-	-	-	-	-	-	-	-	-	3,290
Wind (Planned)	**22**	-	-	-	-	-	-	3,495	1,334	4,224	282	-	48	-	-	-	-	-	-	-	-	6,714	16,098
Total		601	3,189	3,594	172	2,440	3,159	11,857	6,338	10,561	3,913	97	48	-	-	-	-	-	-	-	-	6,714	52,682

Exhibits A-8 through Exhibit A-11 show calculations for the capital costs of units in the model. Units less than 20 years old had the capital costs shown in Exhibit 7 escalated to the year installed using a 2.0% inflation rate to inflate the overnight costs for the specific year the unit was built. A yearly specific CRF calculation was completed for all the units in the model, except for wind and solar. Wind and solar capital costs were calculated using the IHS Markit LCOEs for individual projects based on their on-line year, so one single LCOE does not apply each year across all projects, and therefore are not shown.

Exhibit A-7. Capital Costs

Technology	2016 $/kW	Life	crf
Combined Cycle (Existing)	$1,104	20	0.1003
Combined Cycle (Planned)	$1,104	20	0.1003
Conventional Hydro	$3,123	20	0.1003
CT Gas	$678	20	0.1003
CT Gas (Planned)	$678	20	0.1003
CT Other	$978	20	0.1003
CT Renewable	$978	20	0.1003
Geothermal	$2,805	30	0.0872
Geothermal (Planned)	$2,805	30	0.0872
Fuel Cell	$7,111	20	0.1003
Fuel Cell (Planned)	$7,111	20	0.1003
IC Gas	$818	20	0.1003
IC Oil	$818	20	0.1003
IC Other	$978	20	0.1003
IC Renewable	$4,129	20	0.1003
IC Renewable (Planned)	$4,129	20	0.1003
IGCC (Planned)	$4,026	20	0.1003
Nuclear	$5,883	30	0.0872
Pumped Storage Hydro	$5,626	30	0.0872
ST Coal	$3,636	30	0.0872
ST Coal (Planned)	$3,636	30	0.0872
ST Gas	$1,101	20	0.1003
ST Other	$1,101	20	0.1003
ST Renewable	$1,101	20	0.1003
ST Renewable (Planned)	$1,101	20	0.1003

Note: crf = capital recovery factor

Exhibit A-8. ERCOT Capital Cost Calculations

LEVELIZED CAPITAL COSTS: ERCOT No RPS Resource Schedule ($000s)

	Escalation:	0.888	0.906	0.924	0.942	0.961	0.980	1	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22	1.24	1.27	1.29	1.32	**2010-2030**
Technology	**CRF**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Total**
Combined Cycle (Existing)	0.100341	$134,093	$61,304	$0	$0	$210,671	$75,350	$0	$299,429	$189,762	$0	$27,579	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$998,188
Combined Cycle (Planned)	0.100341	$0	$0	$0	$0	$0	$0	$0	$25,988	$15,328	$5,878	$83,216	$82,557	$0	$0	$130,831	$84,199	$0	$0	$0	$67,065	$0	$495,062
Conventional Hydro	0.100341	$0	$0	$0	$0	$0	$7,373	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,373
CT Gas	0.100341	$22,291	$2,101	$0	$5,641	$0	$24,905	$45,377	$48,505	$16,279	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$165,100
CT Other	0.100341	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
IC Gas	0.100341	$0	$0	$0	$0	$828	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$828
IC Oil	0.100341	$14,760	$0	$0	$0	$0	$0	$22,260	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$37,020
IC Renewable	0.100341	$0	$525	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$525
ST Coal	0.087157	$3,446	$1,837	$0	$0	$1,340	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,623
ST Coal (Planned)	0.087157	$0	$0	$0	$0	$0	$0	$0	$0	$0	$237,427	$0	$0	$251,959	$256,998	$262,138	$267,381	$272,729	$278,183	$283,747	$578,844	$0	$2,689,407
ST Gas	0.100341	$0	$1,101	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,101
ST Renewable	0.100341	$0	$4,403	$10,717	$0	$1,572	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$16,691
Total		$174,590	$71,271	$10,717	$5,641	$214,411	$107,628	$67,637	$373,922	$221,370	$243,305	$110,795	$82,557	$251,959	$256,998	$392,969	$351,580	$272,729	$278,183	$283,747	$645,909	$0	$4,417,918

LEVELIZED CAPITAL COSTS: ERCOT Full RPS Resource Schedule ($000s)

	Escalation:	0.888	0.906	0.924	0.942	0.961	0.980	1	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22	1.24	1.27	1.29	1.32	**2010-2030**
Technology	**CRF**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Total**
Combined Cycle (Existing)	0.100341	$134,093	$61,304	$0	$0	$210,671	$75,350	$0	$299,429	$189,762	$0	$27,579	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$998,188
Combined Cycle (Planned)	0.100341	$0	$0	$0	$0	$0	$0	$0	$25,988	$120,784	$5,878	$83,216	$82,557	$0	$30,921	$130,831	$84,199	$30,383	$0	$0	$0	$0	$594,757
Conventional Hydro	0.100341	$0	$0	$0	$0	$0	$7,373	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,373
CT Gas	0.100341	$22,291	$2,101	$0	$5,641	$0	$24,905	$45,377	$48,505	$16,279	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$165,100
CT Gas (Planned)	0.100341	$0	$0	$0	$0	$0	$0	$0	$32,267	$16,421	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$48,688
CT Other	0.100341	$0	$0	$0	$0	$990	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$990
IC Gas	0.100341	$14,760	$0	$0	$0	$0	$0	$22,260	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$37,020
IC Oil	0.100341	$0	$104	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$104
IC Renewable	0.100341	$4,505	$2,402	$0	$0	$1,752	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,659
Solar PV	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ST Coal	0.087157	$448,270	$82,147	$0	$289,665	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$820,082
ST Coal (Planned)	0.087157	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$262,138	$0	$272,729	$0	$283,747	$0	$0	$818,614
ST Gas	0.100341	$0	$1,101	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,101
ST Renewable	0.100341	$0	$4,403	$10,717	$0	$1,572	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$16,691
Wind	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Wind (Planned)	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total		$623,919	$153,561	$10,717	$295,306	$214,985	$107,628	$67,637	$406,189	$343,246	$5,878	$110,795	$82,557	$0	$30,921	$392,969	$84,199	$303,112	$0	$283,747	$0	$0	$3,517,366

Exhibit A-9. CAISO Capital Cost Calculations

LEVELIZED CAPITAL COSTS: CAISO No RPS Resource Schedule

No RPS - Schedule - $000s	**Escalation**	0.888	0.906	0.924	0.942	0.961	0.980	1	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22	1.24	1.27	1.29	1.32	**2010-2030**
Technology		**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Total**
Combined Cycle (Existing)	0.100341	$101,546	$0	$83,182	$149,357	$0	$0	$41,763	$0	$71,917	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$447,765
Combined Cycle (Planned)	0.100341	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$293,992	$299,871	$305,869	$0	$318,226	$324,591	$331,082	$337,704	$0	$351,347	$358,374	$2,921,056
Conventional Hydro	0.100341	$0	$0	$0	$0	$0	$0	$0	$0	$1,304	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,304
CT Gas	0.100341	$9,726	$18,116	$30,356	$169,211	$3,251	$0	$34,594	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$265,253
CT Renewable	0.100341	$606	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$606
Fuel Cell	0.100341	$0	$646	$2,769	$3,026	$1,783	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,224
Fuel Cell (Planned)	0.100341	$0	$0	$0	$0	$0	$0	$2,854	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,854
IC Gas	0.100341	$12,172	$3,658	$0	$336	$0	$97	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$16,262
IC Oil	0.100341	$0	$2,453	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,453
IC Other	0.100341	$0	$0	$453	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$453
IC Renewable	0.100341	$3,929	$4,303	$0	$3,529	$15,152	$0	$13,175	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$40,088
IC Renewable (Planned)	0.100341	$0	$0	$0	$0	$0	$0	$2,486	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,486
Pumped Storage Hydro	0.0871567	$0	$9,327	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$9,327
ST Gas	0.100341	$383	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$383
ST Renewable	0.100341	$0	$0	$1,817	$0	$0	$2,166	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,983
ST Renewable (Planned)	0.100341	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL		$128,361	$38,502	$118,577	$325,460	$20,186	$2,263	$94,872	$0	$73,221	$0	$293,992	$299,871	$305,869	$0	$318,226	$324,591	$331,082	$337,704	$0	$351,347	$358,374	$3,722,498

LEVELIZED CAPITAL COSTS: CAISO RPS Cost Schedule

RPS Costs Schedule- $000s	Escalation	0.888	0.906	0.924	0.942	0.961	0.980	1	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22	1.24	1.27	1.29	1.32	**2010-2030**
Technology		**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Total**
Combined Cycle (Existing)	0.100341	$101,546	$0	$83,182	$149,357	$0	$0	$41,763	$0	$71,917	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$447,765
Combined Cycle (Planned)	0.100341	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$103,145	$105,208	$107,312	$64,613	$111,647	$113,880	$116,158	$118,481	$0	$123,268	$125,733	$1,089,446
Conventional Hydro	0.100341	$0	$0	$0	$0	$0	$0	$0	$0	$1,304	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,304
CT Gas	0.100341	$9,726	$18,116	$30,356	$169,211	$3,251	$0	$34,594	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$265,253
CT Renewable	0.100341	$606	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$606
Fuel Cell	0.100341	$0	$646	$2,769	$3,026	$1,783	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,224
Fuel Cell (Planned)	0.100341	$0	$0	$0	$0	$0	$0	$2,854	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,854
Geothermal	0.0871567	$5,427	$0	$12,004	$0	$0	$0	$5,501	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$22,932
Geothermal (Planned)	0.0871567	$0	$0	$0	$0	$0	$0	$18,091	$8,229	$0	$10,896	$13,205	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$50,421
IC Gas	0.100341	$12,172	$3,658	$0	$336	$0	$97	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$16,262
IC Oil	0.100341	$0	$2,453	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,453
IC Other	0.100341	$0	$0	$453	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$453
IC Renewable	0.100341	$3,929	$4,303	$0	$3,529	$15,152	$0	$13,175	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$40,088
IC Renewable (Planned)	0.100341	$0	$0	$0	$0	$0	$0	$2,486	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,486
Pumped Storage Hydro	0.0871567	$0	$9,327	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$9,327
Solar	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Solar PV	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Solar PV (Planned)	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Solar Steam	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Solar Steam (Planned)	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ST Gas	0.100341	$383	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$383
ST Renewable	0.100341	$0	$0	$1,817	$0	$0	$2,166	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,983
ST Renewable (Planned)	0.100341	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Wind	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Wind (Planned)	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL		$133,788	$38,502	$130,581	$325,460	$20,186	$2,263	$118,463	$8,229	$73,221	$10,896	$116,350	$105,208	$107,312	$64,613	$111,647	$113,880	$116,158	$118,481	$0	$123,268	$125,733	$1,964,241

Exhibit A-10. MISO Capital Cost Calculations

LEVELIZED CAPITAL COSTS: MISO No RPS - Resource Schedule ($000s)

Technology	Escalation: CRF	0.888 2010	0.906 2011	0.924 2012	0.942 2013	0.961 2014	0.980 2015	1 2016	1.02 2017	1.04 2018	1.06 2019	1.08 2020	1.10 2021	1.13 2022	1.15 2023	1.17 2024	1.20 2025	1.22 2026	1.24 2027	1.27 2028	1.29 2029	1.32 2030	2010-2030 Total
Combined Cycle (Existing)	0.100341	$0	$13,746	$14,584	$10,439	$62,501	$0	$25,368	$146,980	$74,222	$115,206	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$463,045
Combined Cycle (Planned)	0.100341	$0	$0	$0	$0	$0	$0	$0	$0	$0	$224,178	$228,662	$233,235	$237,900	$242,658	$247,511	$252,461	$257,510	$262,661	$267,914	$273,272	$278,738	$3,006,700
Conventional Hydro	0.100341	$0	$2,725	$0	$0	$0	$50,323	$0	$0	$13,432	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$66,480
CT Gas	0.100341	$7,491	$18,085	$0	$0	$11,639	$2,721	$30,022	$0	$552	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$70,511
CT Renewable	0.100341	$1,124	$0	$0	$2,497	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,621
IC Gas	0.100341	$204	$1,264	$0	$0	$0	$0	$6,326	$0	$0	$14,346	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$22,140
IC Oil	0.100341	$1,217	$6,076	$1,845	$1,965	$726	$89	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11,917
IC Renewable	0.100341	$1,803	$5,854	$10,493	$8,201	$2,906	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$29,257
IGCC (Existing)	0.100341	$0	$0	$0	$235,256	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$235,256
Nuclear (Planned)	0.0871567	$0	$0	$0	$0	$0	$0	$0	$784,496	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$784,496
ST Coal	0.0871567	$512,992	$176,522	$476,919	$0	$15,839	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,182,272
ST Coal (Planned)	0.0871567	$0	$0	$0	$0	$0	$0	$0	$0	$0	$653,717	$666,791	$680,127	$693,729	$707,604	$721,756	$736,191	$750,915	$765,933	$781,252	$796,877	$812,815	$8,767,707
ST Gas	0.100341	$0	$0	$0	$0	$452	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$452
ST Other	0.100341	$7,637	$0	$0	$2,915	$106	$0	$1,638	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,296
ST Renewable	0.100341	$0	$1,851	$3,604	$6,246	$4,938	$4,332	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$20,971
Total		$532,467	$226,122	$507,444	$267,518	$99,107	$57,465	$63,354	$931,476	$88,207	$1,007,447	$895,453	$913,362	$931,629	$950,262	$969,267	$988,652	$1,008,426	$1,028,594	$1,049,166	$1,070,149	$1,091,552	$14,677,121

LEVELIZED CAPITAL COSTS: MISO Full RPS - Resource Schedule ($000s)

Technology	Escalation: CRF	0.888 2010	0.906 2011	0.924 2012	0.942 2013	0.961 2014	0.980 2015	1 2016	1.02 2017	1.04 2018	1.06 2019	1.08 2020	1.10 2021	1.13 2022	1.15 2023	1.17 2024	1.20 2025	1.22 2026	1.24 2027	1.27 2028	1.29 2029	1.32 2030	2010-2030 Total
Combined Cycle (Existing)	0.100341	$0	$13,746	$14,584	$10,439	$62,501	$0	$25,368	$146,980	$74,222	$115,206	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$463,045
Combined Cycle (Planned)	0.100341	$0	$0	$0	$0	$0	$0	$0	$0	$0	$225,802	$0	$234,925	$239,623	$244,416	$249,304	$254,290	$259,376	$264,563	$269,855	$275,252	$0	$2,517,406
Conventional Hydro	0.100341	$0	$2,725	$0	$0	$0	$50,323	$0	$0	$13,432	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$66,480
CT Gas	0.100341	$7,491	$18,085	$0	$0	$11,639	$2,721	$30,022	$0	$552	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$70,511
CT Renewable	0.100341	$1,124	$0	$0	$2,497	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,621
Geothermal	0.0871567	$1,211	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,211
IC Gas	0.100341	$204	$1,264	$0	$0	$0	$0	$6,326	$0	$0	$14,346	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$22,140
IC Oil	0.100341	$1,217	$6,076	$1,845	$1,965	$726	$89	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11,917
IC Renewable	0.100341	$1,803	$5,854	$10,493	$8,201	$2,906	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$29,257
IGCC (Existing)	0.100341	$0	$0	$0	$235,256	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$235,256
Nuclear (Planned)	0.0871567	$0	$0	$0	$0	$0	$0	$0	$784,496	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$784,496
Solar PV	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Solar PV (Planned)	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ST Coal	0.0871567	$512,992	$176,522	$476,919	$0	$15,839	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,182,272
ST Coal (Planned)	0.0871567	$0	$0	$0	$0	$0	$0	$0	$0	$657,246	$670,391	$0	$697,474	$711,424	$725,652	$740,165	$754,969	$770,068	$785,469	$801,179	$817,202	$0	$8,131,240
ST Gas	0.100341	$0	$0	$0	$0	$452	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$452
ST Other	0.100341	$7,637	$0	$0	$2,915	$106	$0	$1,638	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,296
ST Renewable	0.100341	$0	$1,851	$3,604	$6,246	$4,938	$4,332	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$20,971
Wind	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Wind (Planned)	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total		$533,679	$226,122	$507,444	$267,518	$99,107	$57,465	$63,354	$931,476	$745,452	$1,025,745	$0	$932,399	$951,047	$970,068	$989,469	$1,009,259	$1,029,444	$1,050,033	$1,071,034	$1,092,454	$0	$13,552,570

Exhibit A-11. PJM Capital Cost Calculations

LEVELIZED CAPITAL COSTS: PJM No RPS Resource Schedule - ($000s)

	Escalation	0.888	0.906	0.924	0.942	0.961	0.980	1	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22	1.24	1.27	1.29	1.32	2010-2030
Technology	**CRF**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Total**
Combined Cycle (Existing)	0.100341	$0	$202,032	$58,303	$6,180	$227,430	$175,288	$399,748	$338,072	$257,357	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,664,411
Combined Cycle (Planned)	0.100341	$0	$0	$0	$0	$0	$0	$76,558	$93,783	$426,317	$794,450	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,391,107
Conventional Hydro	0.100341	$0	$0	$0	$0	$0	$54,224	$7,113	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$61,338
CT Gas	0.100341	$9,182	$709	$25,511	$0	$0	$22,344	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$57,745
CT Gas (Planned)	0.100341	$0	$0	$0	$0	$0	$0	$13,593	$40,011	$16,520	$0	$7,143	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$77,267
CT Other	0.100341	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CT Renewable	0.100341	$148	$862	$725	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,736
IC Gas	0.100341	$0	$0	$0	$0	$0	$1,682	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,682
IC Oil	0.100341	$0	$0	$152	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$152
IC Renewable	0.100341	$3,385	$8,331	$5,091	$8,815	$0	$10,033	$11,849	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$47,503
IGCC (Planned)	0.100341	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Nuclear	0.0871567	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Solar PV	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ST Coal	0.0871567	$0	$0	$388,211	$0	$0	$3,107	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$391,317
ST Gas	0.100341	$0	$0	$0	$0	$0	$28,377	$306,658	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$335,035
ST Other	0.100341	$0	$5,053	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,053
ST Renewable	0.100341	$2,943	$0	$0	$4,935	$0	$25,723	$6,960	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$40,561
Wind	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Wind (Planned)	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total		$15,658	$216,986	$477,992	$19,930	$227,430	$320,778	$822,479	$471,867	$700,194	$794,450	$7,143	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,074,907

LEVELIZED CAPITAL COSTS: PJM Full RPS - Resource Schedule ($000s)

	Escalation	0.888	0.906	0.924	0.942	0.961	0.980	1	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22	1.24	1.27	1.29	1.32	2010-2030
Technology	**CRF**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**Total**
Combined Cycle (Existing)	0.100341	$0	$202,032	$58,303	$6,180	$227,430	$175,288	$399,748	$338,072	$257,357	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,664,411
Combined Cycle (Planned)	0.100341	$0	$0	$0	$0	$0	$0	$76,558	$93,783	$371,342	$397,930	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$939,613
Conventional Hydro	0.100341	$0	$0	$0	$0	$0	$54,224	$7,113	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$61,338
CT Gas	0.100341	$9,182	$709	$25,511	$0	$0	$22,344	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$57,745
CT Gas (Planned)	0.100341	$0	$0	$0	$0	$0	$0	$13,593	$40,011	$16,520	$0	$7,143	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$77,267
CT Renewable	0.100341	$148	$862	$725	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,736
Fuel Cell	0.100341	$0	$0	$1,846	$16,002	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,848
IC Gas	0.100341	$0	$0	$0	$0	$0	$1,682	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,682
IC Gas (Planned)	0.100341	$0	$0	$0	$0	$0	$0	$492	$6,664	$3,399	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,555
IC Oil	0.100341	$0	$0	$152	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$152
IC Renewable	0.100341	$3,385	$8,331	$5,091	$8,815	$0	$10,033	$11,849	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$47,503
IC Renewable (Planned)	0.100341	$0	$0	$0	$0	$0	$0	$14,915	$1,352	$2,069	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$18,336
Solar PV	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Solar PV (Planned)	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ST Coal	0.0871567	$0	$0	$388,211	$0	$0	$3,107	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$391,317
ST Gas	0.100341	$0	$0	$0	$0	$0	$28,377	$306,658	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$335,035
ST Other	0.100341	$0	$5,053	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,053
ST Renewable	0.100341	$2,943	$0	$0	$4,935	$0	$25,723	$6,960	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$40,561
ST Renewable (Planned)	0.100341	$0	$0	$0	$0	$0	$0	$0	$0	$9,195	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$9,195
Wind	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Wind (Planned)	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total		$15,658	$216,986	$479,838	$35,932	$227,430	$320,778	$837,886	$479,883	$659,882	$397,930	$7,143	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,679,347

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