



Virginia Solar Pathways Project

Study 2: Solar PV Generation System Integration Impacts

Final Report

Prepared for:

Dominion Virginia Power



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Content of Report

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ABSTRACT

This report documents Navigant Consulting, Inc.'s ("Navigant") evaluation of the impact of solar photovoltaic ("PV") capacity on Dominion Virginia Power's ("DVP" or "Dominion")¹ interconnected grid, which was commissioned to support the Virginia Solar Pathways Project ("VA SPP"), award No. DE-EE0006914. In partnership with the Department of Energy ("DOE"), the VA SPP aims to develop a collaborative, utility-administered solar strategy for the Commonwealth of Virginia. The goals of the VA SPP are (i) to integrate existing solar programs with new options appropriate for Virginia's policy environment and broader economic development objectives; (ii) to promote wider deployment of solar within a low retail electric rate environment; and (iii) to serve as a replicable model for use by other states with similar policy environments, including but not limited to the entire Southeast region.

The project includes a core advisory team made up of a diverse group of stakeholders. The core advisory team consists of eight entities: Bay Electric Co., Inc., Virginia Department of Mines, Minerals, and Energy, Piedmont Environmental Council, Northern Virginia Community College, Old Dominion University Research Foundation, National Renewable Energy Laboratory, City of Virginia Beach, and Metro Washington Council of Governments. In addition to the core advisory team, DVP envisions providing additional opportunities to share information on project accomplishments with other interested stakeholders.

Navigant's study addresses two distinct topics relating to the integration of solar capacity: The first is a benchmarking and distribution analysis (Study 1: "Distributed Solar Generation Integration and Best Practices Review"), submitted under separate cover. The second study, and the subject of this report, is an evaluation of impacts of solar on the interconnected high-voltage grid (Study 2: "Solar PV Generation System Integration Impacts").

¹ Dominion is one of the nation's largest producers and transporters of energy, with a portfolio of approximately 24,600 megawatts of generation, 12,400 miles of natural gas transmission, gathering, and storage pipeline, and 6,455 miles of electric transmission lines.

LIST OF ACRONYMS

AEP	American Electric Power
AC	Alternating Current
BES	Bulk Electric System
CT	Combustion Turbine
DC	Direct Current
DG	Distributed Generation
DVP	Dominion Virginia Power
IRP	Integrated Resource Plan
LL	Light Load
MW	Megawatt
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation
O&M	Operations and Maintenance
PJM	PJM Interconnection
RAS	Remedial Action Scheme
SP	Summer Peak
SPS	Special Protection Scheme
USS	Utility-scale Solar
VA SPP	Virginia Solar Pathways Project

GLOSSARY

Contingency	The interruption or loss of a line, substation or generating resource that normally is in service. Contingency events may cause other unaffected lines or substation to experience overloads, over-, or under-voltage conditions following a contingency event. Generators may trip off line due to voltage or angular instability, among other potential conditions.
Curtailement	Intentional reduction on line loadings or generator output due to unacceptable or undesirable conditions on the electric power delivery grid. Curtailement may be achieved via automated controls or manual intervention by system operators.
Customer	Interconnecting customer versus DVP customers in service territory
Dynamic	A state variable that changes during small time steps. For the purposes of this report, this term applies to changes that occur in intervals of less than one minute.
Feeder	The distribution line coming from a substation and providing electricity to customers
Ferroresonance	A condition under which over-voltage may occur on transmission or distribution equipment such as power transformers due to single-phase switching or single-phase operation on a three-phase network.
Harmonics	Non-fundamental waveform (e.g. frequency other than 60 hertz) injected into the electric deliver network, caused by non-linear loads or devices, including solar inverters.
Hosting Capacity	The amount of distributed generation that can be connected to a distribution feeder before upgrades to the feeder configuration are required.
IEEE 1547	A standard of the IEEE that provides a set of criteria to interconnect distributed generation to the grid and specify requirements relevant to the performance, operation, testing, safety, and maintenance of the interconnected resources.
Interconnection Cost	A cost that is evaluated at the feeder level to achieve upgrades identified as necessary during the screening of a proposed interconnection resource. These costs are usually borne by the interconnecting customer.
Islanding	Refers to the ability of a distributed resource to energize sections of distribution circuits even after they are disconnected from its source of supply (e.g. after a contingency event). Islanding is a concern as the utility may not have control or monitoring of the distributed resource available to ensure safe operating conditions at the islanded point of the circuit.

Load Tap Changer	A mechanism that is associated with a power transformer to enable changes in the voltage output of the transformer.
Net Energy Metering	Net Energy Metering (NEM) is a utility billing practice for qualified renewable generators on the customer side of the meter. The practice allows qualified renewable generators to use the electric utility system to “bank” generation not used when generated and to receive a bill credit equal to the electricity generated, regardless of the time of the customer’s energy consumption. In Virginia, these distributed generation resources are 1 MW or below.
Overvoltage	Voltage that is sustained above the allowable safe operating threshold identified by the utility.
Radial Lines	Distribution lines where power flow is almost always in one direction, substation to customer load
Secondary Network Systems	Distribution lines that operate in a grid or network configuration, offering very high level of redundancy and reliability
STATCOM Devices	A power electronics voltage-source converter that can act as either a source or sink of reactive AC power
Steady-state	An assumption that holds that the examined system is not changing with time (i.e. it has reached a “steady” state).
Synergi	A software product developed by DNV GL that models and analyzes power distribution systems in a real world spatial environment.
System Upgrade Cost	Certain costs that are evaluated at the distribution system level for a utility that are assessed to be required to enable distributed generation technology to interconnect. As detailed in this document, these costs do not include interconnection, secondary line impacts, communication and control system costs. These costs potentially are borne by all ratepayers.
Transient	A state variable that changes during small time steps. For the purposes of this report, this term applies to changes that occur in intervals of less than one minute.

1. BACKGROUND AND SCOPE

This report presents Navigant's findings and conclusions relating to Virginia Solar Pathways Project ("VA SPP") objectives described in the Abstract and the following overview. It presents the study team's project approach and assumptions applied to derive the findings presented herein, and includes details of the analysis consistent with DVP project objectives.

1.1 Overview

The Solar PV Generation System Integration Impacts study provides a preliminary analysis and roadmap for Dominion Virginia Power ("DVP" or the "Company") to safely and reliably integrate increasing amounts of solar photovoltaics (PV) onto its interconnected transmission and generation system. It includes an evaluation of both Distributed Solar Generation ("DG") and Utility-Scale Solar ("USS"). The analysis and results presented herein address DVP's July 2015 Integrated Resource Plan² ("IRP") for two scenarios (Plans A and B, Solar and Co-Fired, respectively), each of which includes greater amounts of solar generation over a ten-year planning period than what is installed today. The analysis includes an evaluation of distributed and large-scale solar interconnected to DVP's power grid for Plans A and B over the 10-year period, 2015 to 2025. It also includes a determination of the amount of the amount of distributed and large-scale solar that can be installed before the grid reaches a state of criticality, defined as a condition for which solar impacts and the cost to mitigate these impacts become significant. Although theoretical, the analysis includes additional analysis on solar integration far above and beyond the amounts defined in the 2015 IRP.

1.2 Study Objectives and Scope

This study examines how large-scale solar DG penetration may affect grid stability, operability, and reliability for DVP's system. These limits are determined at the point where DVP's operational or planning standards or policies, or those under the jurisdiction of regional entities (such as the PJM and NERC) are violated. It includes detailed analyses of DVP's interconnected grid using state-of-the-art simulation tools to provide the greatest accuracy and consistency with methods DVP currently uses for its operational and planning studies. The study is designed to provide a framework under which Virginia and other regional utilities can evaluate solar impacts with a greater level of rigor and detail, particularly with regard to dynamic analysis of solar impacts, and their impact on net benefits and cost.

Commensurate with the above, this study seeks to support the key policy objectives of the VA SPP:

- Integrate existing solar programs with new options appropriate for Virginia's policy environment and broader economic development objectives
- Promote wider deployment of solar within a low retail electricity rate environment
- Serve as a replicable model for use by other states with similar policy environments including, but not limited to, the entire Southeast region.

While the study attempts to quantify the resulting cost impacts of increasing solar capacity on DVP's system, the cost figures reflected in the study exclude certain significant costs that may be beyond the

² *Integrated Resource Plan*, Dominion Virginia Power and Dominion North Carolina Power, filed with the Virginia State Corporation Commission and North Carolina Utilities Commission on July 15, 2015.

scope of this study, but nonetheless are essential to assessing the true cost impacts of integrating solar into DVP's transmission and generation systems. For the generation system, the development costs of installing and maintaining solar are excluded from the analysis, as only the impacts of the presence of solar were analyzed in this study. Among numerous other project costs, this does not assume the significant initial costs for building and permitting the solar sites, as well as costs to maintain these project sites, which must also be considered when addressing the cost analysis presented in this study.

Additionally, it is important to note that the results of this analysis provide theoretical production costs and production cost values associated with solar integration for the year 2025. Actual future production costs and production cost savings are unknown and unknowable at this time and could vary greatly, depending on actual impact of the relevant cost category inputs (including fuel, emissions, startup, variable operations and maintenance, emissions, and net imports) in 2025.

1.3 Guiding Principles and Assumptions

Navigant and the DVP project team reviewed study methods and assumptions to provide accurate and realistic results. To maintain independent analytical rigor, Navigant prepared the following set of principles to guide the team throughout all phases of the study.

1. The methodology should be consistent with prior state-of-the-art industry studies, but with additional detail and analytical rigor.
2. The methodology should also provide sufficient flexibility to update the analytical approach and results as new data become available (from both DVP and from industry).
3. Comprehensive, industry-accepted simulation models and methods should be applied to produce the most accurate results.
4. The study starts with the July 2015, DVP IRP, Plans A and B, as an underlying foundation.
5. Integration benefits and costs should be based on a realistic forecast of enabling solutions and commercially available technologies.
6. Study methods and results should be transparent and consistent with industry standards for solar technology assessment.
7. All assumptions, methods, and results are reviewed and vetted by a cross-section of DVP experts throughout the organization.

Detailed assumptions for the transmission and generation studies are presented in their respective sections of this report. Key overarching study assumptions are listed below.

- Reliability and performance must be maintained at current levels for both DVP's transmission and generation systems.
- The analysis includes evaluation of impacts of solar PV³ on DVP generation and transmission assets within DVP's service area, and on adjacent utility systems.
- For the transmission analysis, USS projects are modeled as connected to DVP's transmission system. DG is modeled as negative load to represent the capacity of the DG site on the distribution system.

³ Hereinafter, all solar DG and USS is assumed to be PV.

- All solar project development costs, capital, development, and interconnection costs, are not included in the analysis presented in the study.
- A potential benefit of transmission capacity deferral is not included in the benefits analysis due to the intermittent output of solar power and its limited ability to justify opportunities for investment deferral.
- Solutions to address constraints and violations for the base case studies are based on currently available and commercially viable technology.
- All solar capacities presented in the report are alternating current (“AC”) versus direct current (“DC”) rating.

Because solar DG and USS were distributed throughout DVP’s service territory, with the largest individual unit on any substation bus set at 25 MW, the impact of variances due to cloud cover or loss of individual solar unit(s) on transmission system performance is small compared to other contingencies studied (e.g., loss of individual lines or generators). Changes in assumptions to solar capacity growth rates and locations, including increased clustering of solar projects coupled with larger individual units, could yield greater transmission system impacts, both in transient and steady state.

Also, the transient analysis focused on a limited set of the most severe contingencies rather than all possible contingencies. A more comprehensive transient stability analysis will be necessary as solar capacity increases. Changes to the solar allocation and assumptions for the conventional generators would result in different findings, including the system upgrades and critical level of solar for each solar scenario.

1.4 Methodology

The following summarizes the methods and assumptions Navigant applied to conduct its evaluation of solar DG and USS on DVP’s interconnected transmission grid. It includes three sets of analytical studies: The first two analyze solar scenarios outlined in Plans A and B of DVP’s July 2015 IRP. The third identifies the amount of solar USS and DG that can be connected to the transmission and generation system, before it reaches criticality.

Generation and transmission impacts of solar DG and USS in DVP’s service territory include the following cost and performance metrics.

Generation

- Ancillary services (e.g., load following, operating reserves, reactive supply)
- Generation production costs
- Impact on existing generators due to ramping
- Impact on reserve margins

Transmission

- Transmission system voltages
- Power flows, and impact of reverse flows on the system
- Power quality issues originating in the distribution system
- Impact to transmission constraints

- Technical energy losses in the transmission and distribution systems
- Grid stability (e.g., impact of sudden loss of solar energy on grid stability)

This report is also designed to discuss the approach the study team applied to evaluate DG and USS impacts on DVP's generation and transmission systems.⁴

The following sections present Navigant's methodology and results for the transmission and generation studies. The first step in the evaluation is an allocation of solar DG and USS capacity throughout DVP's service territory.

Simulation analyses of DVP's transmission and generation system were performed for three solar scenarios: (1) DG-only; (2) USS; and (3) a Hybrid scenario comprised of equal amounts of DG and USS. The evaluation includes increasing the amount of solar capacity for each scenario in an effort to determine critical levels of solar as defined above.

Sections 1 and 2 of this report summarize VA SPP objectives and the approach for the Solar PV Generation System Integration Study (Study 2), as well as the methodology for allocation of solar DG and USS used in the transmission and generation analyses.

Sections 3 and 4 present Navigant's findings for the transmission and generation studies, including net benefits and costs for IRP Plans A and B, and a higher solar penetration case designed to determine critical levels of solar capacity. Sections 5 and 6 summarize future studies and analysis, and Navigant's findings and conclusions.

⁴ Grid impacts on the higher voltage transmission system include facilities rated above 69 kV. Distribution system impacts are addressed in Study 1.

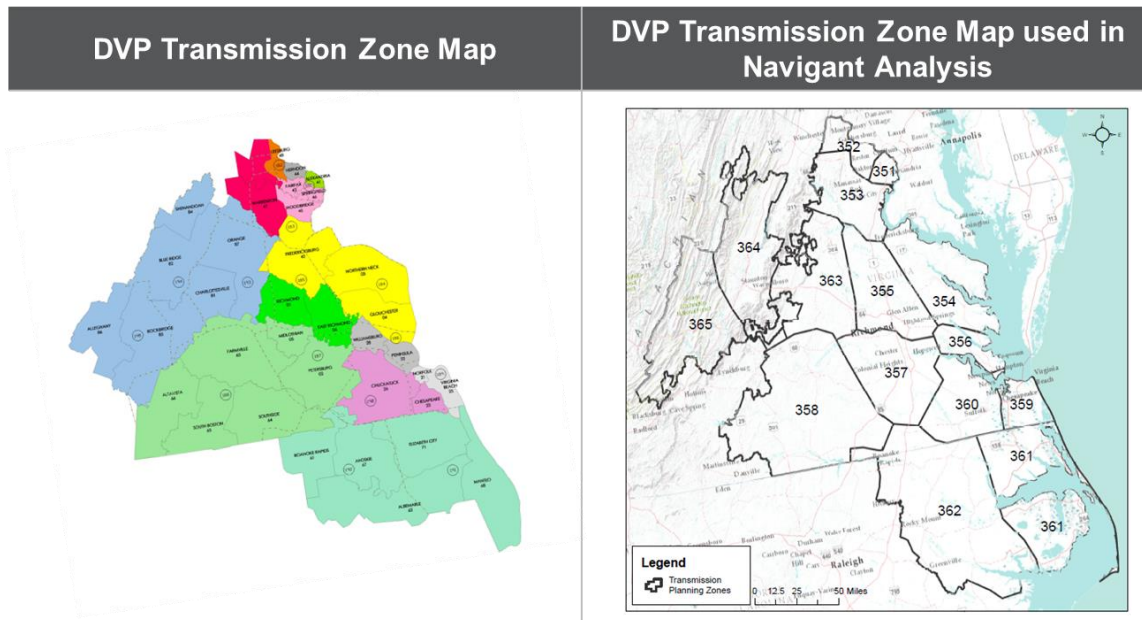
2. SOLAR CAPACITY LEVELS AND ALLOCATION

The allocation of solar PV capacity to locations throughout DVP’s service territory is an important part of the analysis, as the location of DG systems may not follow the same patterns as USS. Solar DG typically is a function of the number of customers in an area, adjusted to reflect economic drivers that promote or encourage the purchase of DG. The location of USS is driven by both land-use factors and economic factors.

2.1 Solar Allocation Methodology

Solar capacity was allocated to the 15 transmission zones, as defined by DVP in their service territory, depicted in Figure 2-1.

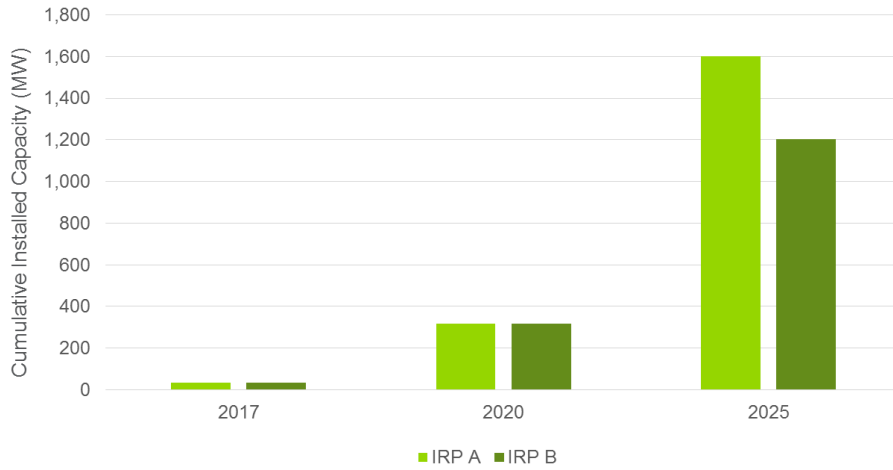
Figure 2-1. DVP Transmission Zones



Source: DVP (left); Navigant (right)

The total amount of DG and USS capacity allocated within each DVP zone is based on the solar levels contained in Plans A and B of the 2015 IRP. Figure 2-2 presents these levels for 2017, 2020 and 2025.

Figure 2-2. DVP IRP Solar Levels



Source: Navigant analysis of DVP IRP

The USS and DG allocation methodologies are somewhat different, which results in unique allocation percentages for USS and DG as shown in Table 2-1. These percentages were applied for all solar levels indicated in the report. The methods and processes used by Navigant to allocate DG and USS capacity to the DVP transmission zones are described in the following two subsections. Note that each column sums to 100% of the total DVP IRP forecasted solar capacity levels within each type of solar system.

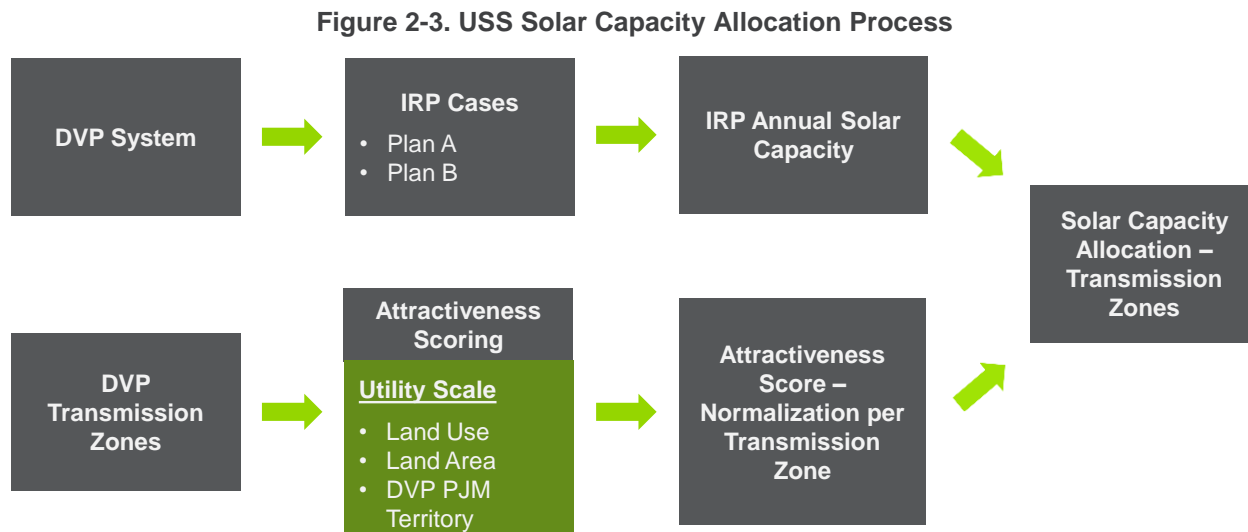
Table 2-1. Percentage Allocation for USS and DG Solar

Zone	USS Allocation	DG Allocation
351	1.9%	14.5%
352	3.4%	20.6%
353	6.0%	8.5%
354	4.7%	3.3%
355	7.0%	10.4%
356	2.0%	7.1%
357	7.7%	8.2%
358	18.2%	3.1%
359	3.5%	11.8%
360	4.9%	4.1%
361	4.5%	0.0%
362	15.2%	0.0%
363	8.0%	4.1%
364	8.4%	2.5%
365	4.6%	1.8%

Source: Navigant

2.2 Utility-Scale Solar Allocation to Transmission Zones

The allocation of USS capacity for IRP Plans A and B is based on “attractiveness” scores assigned to each DVP transmission zone. Figure 2-3 illustrates major steps undertaken in the allocation process.



Source: Navigant

The allocation of USS capacity is guided by the following criteria, each of which was a factor in areas where USS is likely to be located. The location and capacity of USS was based on attractiveness scoring based the following criteria:

- Restricting capacity additions to locations that are suitable for USS given topology, land availability, environmental factors, land-use restrictions, and other relevant criteria;
- Sites and substation interconnections within 5 to 10 miles of ocean shorelines are excluded, as the likelihood of suitable and available sites is limited; and
- Assigning attractiveness scores and weightings in areas where solar capacity provides support to the transmission system, including those within urban zones.

Navigant selected 15 USGS land cover classifications to define an attractiveness score for each zone. Each land cover classification was assigned a weight from 0-5 based on the suitability of the land type for utility scale solar development, with higher weights designating higher suitability. For example, the USGS category “Developed, Open Space” is highly suitable for development, and corresponds to a weight of 5.

Conversely, the USGS category “Woody Wetlands” is not suitable for development, and corresponds to a weight of 0. The land use categories and associated weightings are provided in Table 2-2

Table 2-2. Land Use Categories and USS Weighting

Land Use	USGS Code	USS Weighting
Open Water	11	0
Developed, Open Space	21	5
Developed, Low Intensity	22	5
Developed, Medium Intensity	23	3
Developed, High Intensity	24	2
Barren Land (Rock/ Sand/ Clay)	31	5
Deciduous Forest	41	0*
Evergreen Forest	42	0*
Mixed Forest	43	0*
Shrub/ Scrub	52	4
Grassland/ Herbaceous	71	5
Pasture/ Hay	81	3
Cultivated Crops	82	0*
Woody Wetlands	90	0
Emergent Herbaceous Wetlands	95	0

** Some land owners may be eligible to receive a payment for lumber production and may instead lease land for solar project development, or arable land could be converted to solar development.
Source: Navigant*

The results of the analysis defined areas suitable for utility-scale solar PV development within DVP's transmission zones. Table 2-3 provides the USS suitability score for USS by zone, derived by multiplying the weighting by the square miles of the land use category by zone.

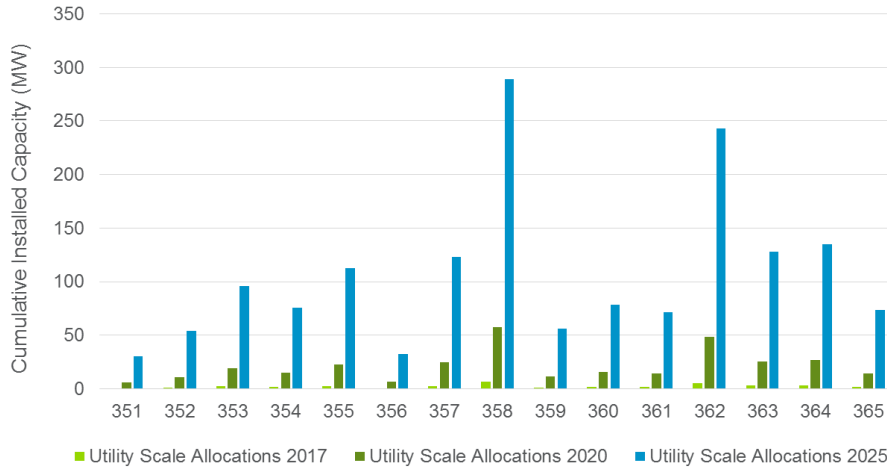
Table 2-3. USS Suitability Score by Zone

Zone	USS Suitability Score	Rank
351	762	15
352	1368	13
353	2419	7
354	1914	9
355	2842	6
356	818	14
357	3111	5
358	7298	1
359	1427	12
360	1989	8
361	1807	11
362	6146	2
363	3233	4
364	3404	3
365	1852	10

Source: Navigant's analysis incorporates ESRI, DeLorme, USGS, NPS, NOAA, Ventyx, and DVP data.

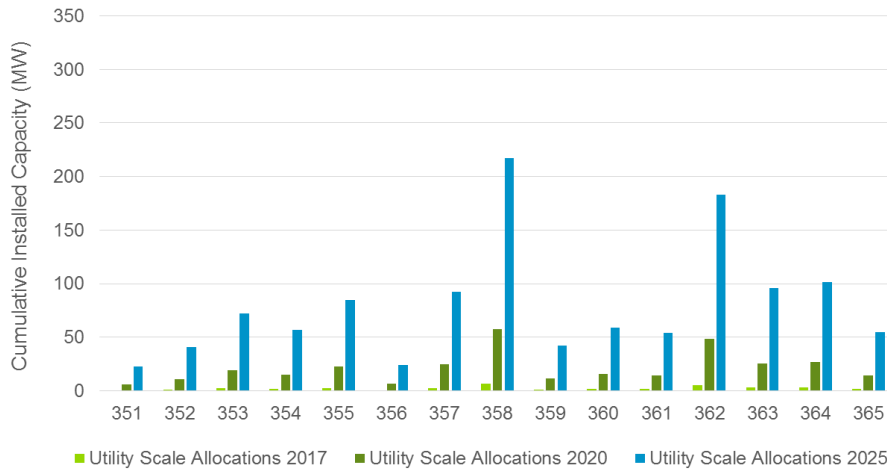
Figure 2-4 and Figure 2-5 present the results of the USS allocation for IRP Plans A and B, respectively. For USS, solar capacity tends to be more heavily clustered in rural areas in western and northern Virginia (e.g., Zone 358), with the lowest amounts in eastern areas, which are generally more urban and suburban.

Figure 2-4. DVP 2015 IRP Plan A: USS Capacity Allocation



Source: Navigant

Figure 2-5. DVP 2015 IRP Plan B: USS Capacity Allocation



Source: Navigant

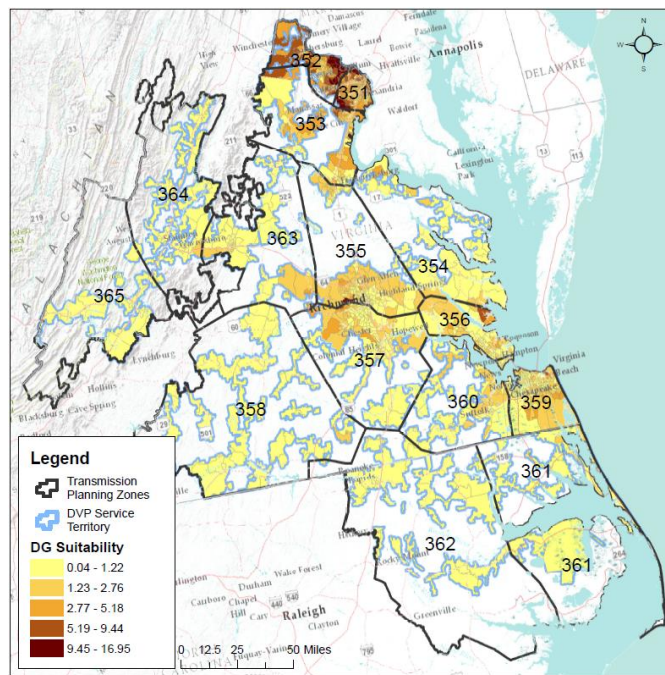
2.3 Distributed Solar Allocation to Transmission Zones

For distributed solar, a combination of residential load, commercial customer load, household income, and home values were used to allocate distributed solar capacity to each transmission zone. The U.S.

Census provides average income and housing values in each zone, for which each was equally weighted to develop attractiveness scores.

The use of customer load, and housing and income values, each with equal weighting, produced DG suitability scores for each census tract in each transmission zone for solar DG. Figure 2-6 illustrates the DVP distribution service territory and which areas are more likely than others to experience higher penetration of solar DG. The scores tend to be higher in areas with higher customer counts, and generally higher income and housing values, such as areas near Richmond and northern Virginia. These trends appear to match those presented in Figure 2-7 for existing net energy metering (NEM), particularly in northern Virginia, where housing value and income is up to twice the average compared to other parts of the state.

Figure 2-6. DG Suitability by Transmission Zone

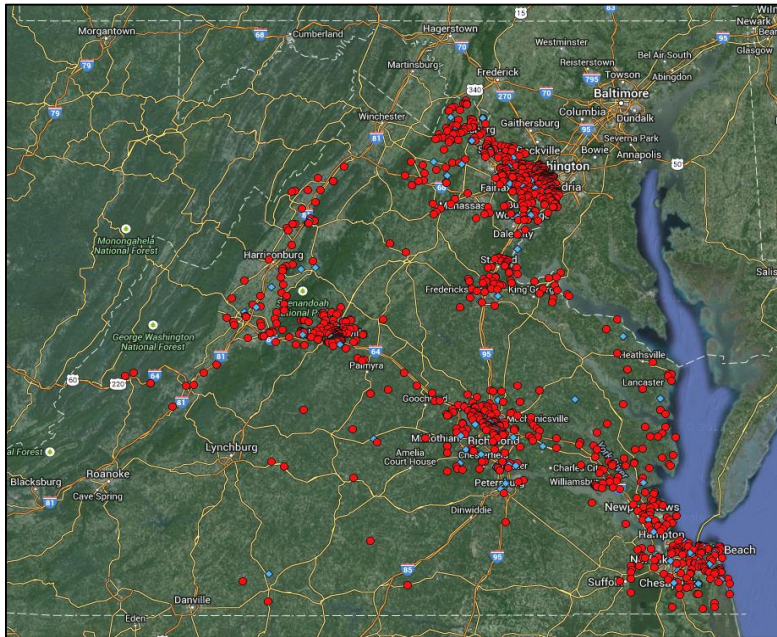


Source: Navigant's analysis incorporates ESRI, DeLorme, USGS, NPS, NOAA, Ventyx, and DVP data.

For comparison, allocations from Figure 2-6 are compared to existing NEM data. Currently, there are approximately 1,400 residential and commercial NEM customers in DVP's Virginia service territory with solar DG for a total of 10 MW of installed capacity. The vast majority of these installation are rated 10 kW

and below. Figure 2-7 illustrates the location of existing NEM, which confirms most are located in more populated urban areas.

Figure 2-7. Existing NEM Locations in DVP’s Virginia Service Territory (2015)



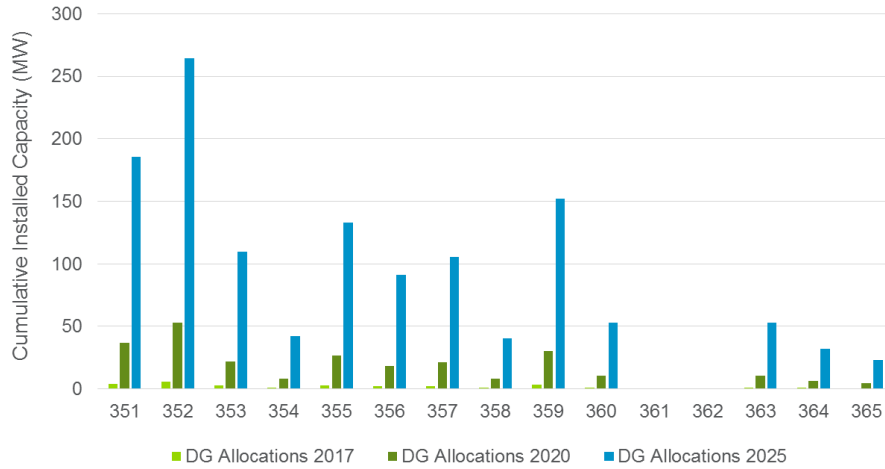
*Residential NEM in red; commercial installations in blue
Source: DVP*

The census data approach results in greater clustering of DG, which represents a more realistic outcome for NEM solar, based on nationwide trends. The most significant deviations typically occur in rural areas, due to lower average housing values and income. Existing NEM data, while limited within DVP’s service area, confirm that zones with higher average household income and greater average home values, such as in Richmond and northern Virginia, are likely to have greater DG capacity installed per customer.

Navigant applied the suitability scores, in combination with customer census data, to allocate total solar capacity forecast to individual zones. Figure 2-8 and Figure 2-9 present DVP’s IRP Plan A and B DG

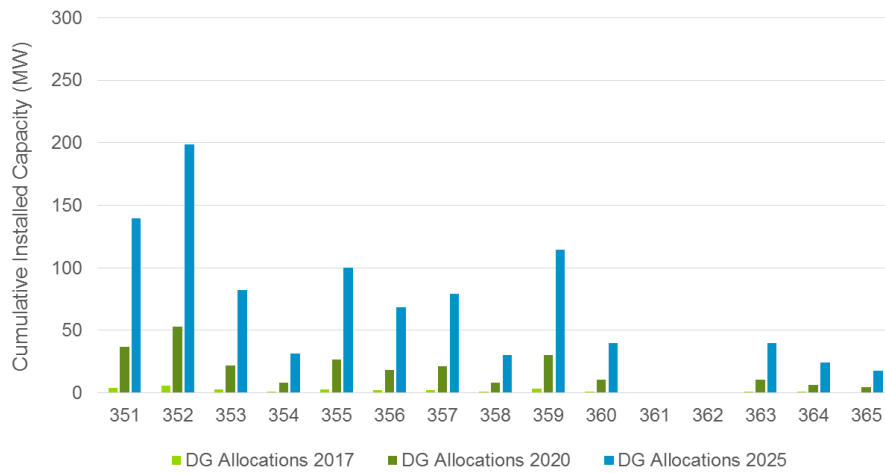
capacity allocations for 2017, 2020 and 2025. There is no DG assigned to in Zones 361 and 362, as each are predominantly in rural North Carolina.

Figure 2-8. DVP 2015 IRP Plan A: Solar DG Capacity Allocation



Source: Navigant

Figure 2-9. DVP 2015 IRP Plan B: Solar DG Capacity Allocation



Source: Navigant

The results presented above identify the amount of solar capacity allocated to the DVP transmission zones for 2015 IRP Plans A and B, respectively.

2.4 Solar Allocation to Busses

The USS capacity was allocated within a zone by sorting and prioritizing those busses which were the most lightly loaded. The USS capacity was first assigned to be connected to the most lightly loaded bus in the zone, and then the next most lightly loaded bus in each zone, until the accumulated amount of USS capacity in the zone reached the total amount allocated to the zone. The size of the USS capacity was

assumed to be 10 MW in zones 351, 352, 353, 354, 356, 359, and 360 because these areas are more urban/suburban in eastern zones. In the other DVP zones, the size of the USS capacity was assumed to be 25 MW.

The solar DG was allocated within a zone by prioritizing those buses which were more heavily loaded by proportionally allocating the DG in the same percentage as a bus's share of the zone's peak load.

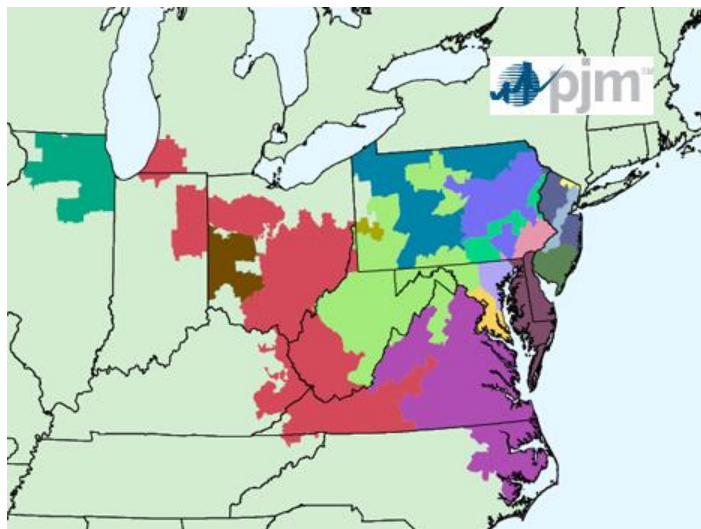
3. TRANSMISSION ANALYSIS

The impact of solar DG and USS on DVP’s transmission grid, and other utility systems with direct ties to DVP, is presented in this section. This analysis includes a determination of the state at which solar PV capacity creates significant impacts, referred to as the level of criticality, and possible mitigation solutions once the threshold is exceeded. Studies that identify optimum placement of large-scale solar are presented as an alternative solution to address impacts. System benefits, in the form of reduction in electric energy losses, are derived for each solar scenario.

Transmission study results presented in the following sections are based on steady-state and dynamic simulation analyses that provide a qualified perspective of the impact of solar generation on DVP’s interconnected grid. Transmission impacts resulting from high levels of solar PV capacity include those resulting under normal and contingency conditions. Results include shifts in line loadings, as well as shifts in post-contingency bus voltages, due to solar displacement of conventional generation. This is driven by the fact that USS sources are typically not in the same electrical vicinity where generator output has been displaced by solar. Large swings in solar PV output can create unacceptable voltages and power quality concerns.

Because DVP’s transmission system is interconnected with other key utilities in the Eastern Interconnection, most of Dominion’s high-voltage network (230 kV and greater) is impacted by bulk power flows from the Midwest into the mid-Atlantic load centers. Accordingly, the analysis identified impacts that may occur on transmission ties to adjacent utility networks, both within the PJM Interconnection (“PJM”)⁵ and for regions south of DVP’s service territory, such as ties to Duke Energy. Figure 3-1 illustrates the locations of DVP and other utility networks within the PJM system.

Figure 3-1. PJM Network



*DVP’s network is shown in purple (Central and Eastern Virginia and northeastern North Carolina)
Source: PJM*

⁵ PJM is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia.

3.1 Simulation Modeling

For each solar case, Navigant utilized the Siemens' Power System Simulator for Engineering (PSS/E) software model to execute transmission simulation analyses of the interconnected grid. The PSS/E model is the same transmission analysis tool used by DVP and other transmission entities throughout the PJM region. The network model includes neighboring regions to ensure potential impacts are identified; the key neighboring regions studied include adjacent utilities within and outside of PJM.⁶ For example, DVP borders American Electric Power (AEP) and Potomac Electric Power Company (Pepco) which are member companies in PJM. Accordingly, critical seams (i.e., major ties to adjacent systems) in the study were also addressed.

Key modeling assumptions and conventions applied in the study are highlighted below.

- Steady-state load flow analysis is performed for a 2020 case under summer peak and light load conditions.
- The analysis is based on transmission and generation expansion plans outlined in DVP's July 2015 IRP, including generation retirements and expansion plans as of 2020.
- Solar impacts are analyzed for sixteen zones within DVP's system for each of the following solar levels: 500 MW; 2,000 MW; 4,000 MW; and 6,000 MW; and for all DG, all USS, and a Hybrid scenario. These solar levels are theoretical and are used solely for purposes of analysis.
- USS is assumed to be connected directly to substation busses greater than 69 kV and less than 500 kV within each zone; interconnection facilities and costs are the responsibility of the USS generation facility developer and owner, and were excluded from consideration in this analysis.
- The solar allocation to each zone of DG and USS for each solar level and scenario is provided in Appendix A.
- The USS capacity was allocated within a zone by prioritizing those busses which were lightly loaded. The USS was assumed to be connected to the most lightly loaded bus in the zone, and then the next most lightly loaded bus in the zone until the amount of the USS in the zone reached the amount allocated to the zone. The size of the USS was assumed to be 10 MW in zones 351, 352, 353, 354, 356, 359, and 360 because these areas are more urban/suburban. In the other DVP zones the size of the USS was assumed to be 25 MW.
- The solar DG was allocated within a zone by prioritizing those buses which were more heavily loaded, by proportionally allocating the DG in the same percentage as a bus's share of the zone's peak load.
- USS is modeled as a generator with the power factor operating range of 0.95 lead and lag.⁷ DG is modeled as negative load to represent the capacity of the DG site on the distribution system. It is assumed that there is no reactive support from the solar DG.
- Contingency events analyzed via PSS/E align with those used by DVP in its own studies.
- PJM generation output levels are reduced based on a dispatch priority order for DVP generating units, in amounts equal to the amount of solar capacity installed.

⁶ However, solar generation and other non-committed third-party generators that are not included in PJM's most recent Regional Transmission Expansion Plan, but currently in the PJM queue, are omitted from the analysis.

⁷ USS is not currently required to provide reactive power, but it will become a requirement for any USS that entered the queue in May 2015 or later.

- Event files modified based upon monitored/contingency pairs from PSS/E studies are used to inform the power flow data used in the production simulation model (Promod) for generation studies in Section 4.
- Only normal conditions and single contingencies are deemed to create violations under the assumption that double contingencies are addressed by PJM authorized special protection or remedial action schemes (SPS or RAS)).
- Monitored busses include all DVP and AEP transmission 100 kV and higher, and all adjacent PJM and SERC transmission busses greater than 200 kV.
- Results from the steady-state contingency studies are used to inform dynamic system studies to identify areas and conditions under which the system is most susceptible to transient impacts.
- Study impacts and mitigation steps recognize and consider the flexibility of the pumped storage Bath County Facility, along with potential additional storage capacity to be added to the bulk power system.

Results from all studies, including maps, tables, and charts exclude any information or data that are deemed to be subject to Critical Energy Infrastructure Information (CEII) restrictions.⁸

3.2 Steady-State Analysis

Steady-state load flow studies were conducted for a reference case and three solar scenarios (subsequently defined) to determine the extent to which thermal loading or voltage violations occur for increasing amounts of solar PV capacity. Steady-state analyses were performed using a modified PJM 2020 PSS/E model, updated to include DVP generation and transmission expansion and retirement plans, as outlined in DVP's July 2015 IRP, as of 2020.⁹

Steady-state transmission studies include evaluation of increasing amounts of solar capacity for the following reference case and solar scenarios.

1. A "reference" scenario for which no new solar generation capacity is modeled
2. 100% USS
3. 100% DG
4. 50% DG and 50% USS (Hybrid)

Specific impacts investigated include:

- Line and transformer thermal overloads (normal and post-contingency);
- Steady-state voltage (normal and post-contingency);
- Inertie power transfers (real and reactive);
- Impact of reverse flows on the bulk electric system (BES); for example, east to west flows back towards the west, if applicable; and

⁸ CEII is specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure (physical or virtual) that relates details about the production, generation, transmission, or distribution of energy, and is exempt from mandatory disclosure under the Freedom of Information Act.

⁹ Generation additions for the 2020 case include Brunswick County and Greenville County Combined Cycle units; and retirements include Chesapeake CT 1, 2; Chesterfield 3, 4; Gravel Neck 1; Lowmoor CT; Mecklenburg 1,2; Mount Storm CT; Northern Neck CT; Yorktown 1, 2, 3 from DVP's IRP (unit ratings appear in Table D-4).

- Avoided/additional losses on the transmission systems.

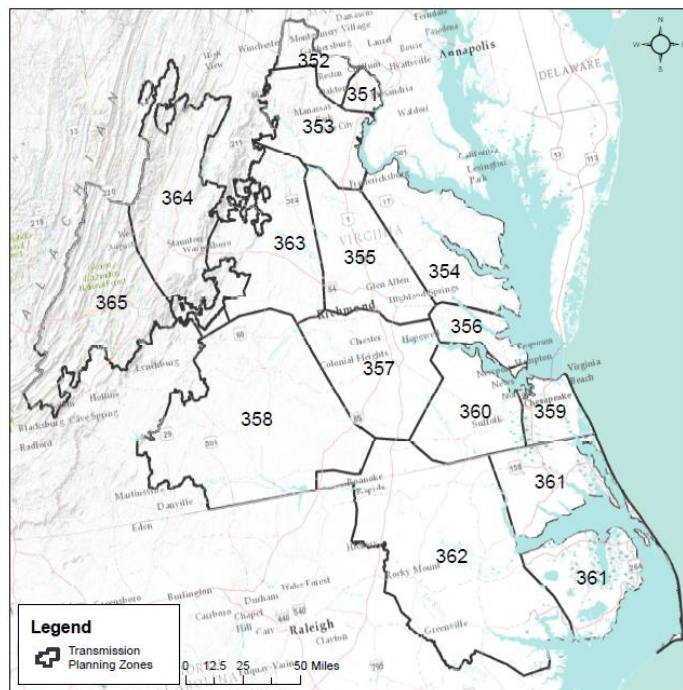
Where violations or constraints are identified, upgrades or mitigation options were selected based on least-cost solutions. Candidate mitigation options include system upgrades or additions, reactive support or controls (e.g., Static VAR Compensation), generation run-back, and special protection schemes, where applicable and agreed upon by DVP’s Transmission Planning department.

Changes in the assumptions for the zonal allocation, allocation to busses, and the size of the solar facilities as described in Section 2 could yield greater transmission system impacts. For example, larger USS project sizes, or increased clustering of these facilities, would likely yield greater transmission system impacts. Similarly, changes to assumptions for the conventional generators or customer demand would result in different findings.

3.2.1 DVP Transmission Zones

The capability of DVP’s transmission system to accommodate higher levels of solar PV capacity varies according to location, and is a function of the amount of load, robustness of the interconnected grid, and amount of generation within or near each zone. Figure 3-2 presents DVP’s transmission zones (15) for Virginia and North Carolina. Both states are illustrated because USS may be owned by DVP or third parties and located outside of Virginia, whereas the DG assessment focuses solely on facilities owned and operated by DVP customers in Virginia.

Figure 3-2. DVP Transmission Zones



Source: Navigant’s analysis incorporates ESRI, DeLorme, USGS, NPS, NOAA, Ventyx, and DVP data.

The steady-state analysis examines the impact of solar DG and USS on DVP and adjacent systems within and outside PJM’s footprint for 2020. Solar impacts are evaluated via PSS/E analysis under normal

and contingency conditions, consistent with assumptions and evaluations conducted by DVP and PJM. All analyses are performed by comparing solar penetration case results to a reference case with no future solar to quantify incremental solar impacts. Results from the reference case provide a baseline for assessing solar impacts, as some transmission lines and substation transformers may be near their maximum operational capacity, for which a small amount of incremental solar PV can readily breach the threshold.

Recognizing that small amounts of solar can create minor violations, (e.g., bus voltages one percent above normal maximum of 1.05 per unit), voltage and thermal thresholds were established such that violations must exceed reference case levels by 1% and 3%, respectively, to constitute a reportable violation. This avoids the reporting of numerous inconsequential violations, most of which can be corrected by operator or automated action, such as switching capacitor banks or adjusting generating output.¹⁰ The upper and lower thermal and voltage thresholds listed in Table 3-1 identify states at which material normal or contingency violations are assigned (applies to both summer peak and light load cases).

Table 3-1. Steady-State Limits (Per Unit)

Violation Category	Lower Limit	Upper Limit	Minimum Difference*
Thermal (<500 kV)	N/A	0.94	3%
Thermal (500 kV)	N/A	0.94	6%
Voltage (<300 kV)	0.93	1.05	1%
Voltage (≥300 kV)	1.01	1.08	1%

**Difference between post-contingency loadings of solar versus reference (no solar) case results
Source: DVP*

3.2.2 Summer Peak Analysis

The following two sections present thermal and voltage violations for the summer peak cases. This includes the number of contingencies causing violations, by voltage, for each DVP zone and tie line to adjacent systems. To analyze impacts of solar penetration, 12 cases were created. There include three solar scenarios, DG, USS, and Hybrid, and four penetration levels, 500 MW, 2,000 MW, 4,000 MW, and 6,000 MW. An AC contingency analysis was performed for each case, along with the reference case, using the same set of PSS/E parameters. The results of the contingency analysis were compared to reference case results to determine the number and severity of thermal and voltage violations. The real and reactive reserves for each case are included in Appendix B.

¹⁰ For unsolved solar reference cases, Navigant manually adjusted transformer taps, shunts, and generator settings to bring voltages or loadings within limits.

3.2.2.1 Thermal Violations

Table 3-2 presents thermal violation results for each of the three solar capacity scenarios by voltage level for the summer peak cases.

Table 3-2. Steady-State Thermal Violations (Summer Peak, 2020)*

Voltage		115/138 kV		230 kV		500 kV	
Scenario	Case (MW)	No. of Contingencies	No. of Violations	No. of Contingencies	No. of Violations	No. of Contingencies	No. of Violations
DG	500	No Violations at this Level					
DG	2,000	No Violations at this Level					
DG	4,000	0	0	1	1	0	0
DG	6,000	No Violations at this Level					
Hybrid	500	No Violations at this Level					
Hybrid	2,000	0	0	0	0	1	1
Hybrid	4,000	0	0	1	1	1	1
Hybrid	6,000	32	1	9	3	1	1
USS	500	0	0	0	0	1	1
USS	2,000	0	0	0	0	1	1
USS	4,000	45	1	9	3	1	1
USS	6,000	45	8	150	5	1	1

*A column for 345 kV lines does not appear as there are no lines rated at 345 kV in DVP's service territory, and there are no violations detected on other utility systems.

Source: Navigant

Table 3-3 presents thermal violations reported in Table 3-2 for each zone displayed in Figure 3-2, obtained from PSS/E 2020 load flow results. (Only zones where violations are detected appear in the table.) Zone 366 contains only lines rated 500 kV in areas designated 355-357, which are intra-zonal lines between the Richmond (Zone 355) and Chesterfield (Zone 357) zones. The installation of USS in the

Richmond and Chesterfield areas, coupled with Chesterfield Power Station’s generation output, each contribute to line overloads cited above.

Table 3-3. Thermal Violations by Zone (Summer Peak, 2020)*

Scenario	Case (MW)	353	355	357	358	362	366	355-357
DG	500	No Violations at this Level						
DG	2,000	No Violations at this Level						
DG	4,000	1	0	0	0	0	0	0
DG	6,000	No Violations at this Level						
Hybrid	500	No Violations at this Level						
Hybrid	2,000	0	0	0	0	0	1	0
Hybrid	4,000	1	0	0	0	0	1	0
Hybrid	6,000	1	1	0	0	1	1	1
USS	500	0	0	0	0	0	1	0
USS	2,000	0	0	0	0	0	1	0
USS	4,000	1	1	0	0	1	1	1
USS	6,000	1	2	1	1	7	1	1

*Zone locations appear in Figure 3-2
 Source: Navigant

Table 3-4 presents maximum thermal overloads for each zone displayed in Figure 2-1 from PSS/E 2020 load flow results. All values are percent of normal line rating; dashes indicate no violation was detected. All DG scenarios up to 2,000 MW show no overloads, and for Hybrid and USS scenarios, violations occur only on a 500 kV line.¹¹ The highest number and level of overloads occur for the Hybrid and USS cases, with a maximum overload of 24% in Zone 357 (i.e., 118% minus 94% threshold). Zone 362 (North

¹¹ Contingency overload violations on the same 500 kV line also occur for the reference case (no solar). Therefore, only violations that exceed the 3% threshold proscribed in Table 3-1 appear in Table 3-4.

Carolina) has among the highest percentages of USS capacity (Table 2-1), while violations in Zone 355 (Richmond) are due to Chesterfield Power Station generation (swing bus), and overloads in the region.

Table 3-4. Maximum Thermal Violations by Zone (Summer Peak, 2020)

Solar Scenario	Case (MW)	353	355	357	358	362	366	355-357
DG	500	No Violations at this Level						
DG	2,000	No Violations at this Level						
DG	4,000	98.5	-	-	-	-	-	-
DG	6,000	No Violations at this Level						
Hybrid	500	No Violations at this Level						
Hybrid	2,000	-	-	-	-	-	98.8	-
Hybrid	4,000	102.8	-	-	-	-	99.6	-
Hybrid	6,000	96.1	102.4	-	-	99.2	101.7	102.8
USS	500	-	-	-	-	-	96.9	-
USS	2,000	-	-	-	-	-	100.9	-
USS	4,000	105.8	-	96.6	-	99.2	103.1	97.0
USS	6,000	104.1	115.4	117.6	102.7	103.4	106.4	118.1

Source: Navigant

3.2.2.2 Voltage Violations

Table 3-5 presents the voltage violations for each of the three solar capacity scenarios for the summer peak cases. Results indicate very few violations occur for low solar capacities (500 MW to 2,000 MW); of these, most are on transmission lines and busses rated 115 kV and 138 kV.

Table 3-5. Steady-State Voltage Violations (Summer Peak, 2020)

Voltage		115/138 kV		230 kV		500 kV	
Solar Scenario	Case (MW)	No. of Contingencies	No. of Violations	No. of Contingencies	No. of Violations	No. of Contingencies	No. of Violations
DG	500	No Violations at this Level					
DG	2,000	6	6	0	0	0	0
DG	4,000	44	17	0	0	0	0
DG	6,000	79	32	9	6	0	0
Hybrid	500	No Violations at this Level					
Hybrid	2,000	7	7	0	0	0	0
Hybrid	4,000	20	16	0	0	0	0
Hybrid	6,000	21	16	0	0	0	0
USS	500	No Violations at this Level					
USS	2,000	3	3	0	0	0	0
USS	4,000	7	7	0	0	0	0
USS	6,000	5	5	0	0	0	0

Source: Navigant

Most violations are high bus voltages, a condition commonly encountered by Navigant in solar integration studies. The only low voltage violation occurs for higher solar penetration at busses where adjacent lines to the bus are out of service due to a contingency. The low voltage condition is caused, in part, by the reduction in conventional generation output via solar displacement. There are relatively few violations on 230 kV busses, and these occurred only in the DG and Hybrid cases. There are no violations on the 500 kV system.

There are fewer voltage violations for the USS than for the DG scenario, particularly at higher solar penetration levels, as USS provides post-contingency reactive support. The ability to adjust power factor on USS generation avoids many high-voltage violations as reactive power is either supplied or absorbed, depending on system conditions. Further, violations in the Hybrid and USS scenarios can be mitigated by adjusting fixed capacitor banks via installation of switches and controls, as reactive support from these banks is replaced by USS sources. Also, the decrease in the number of voltage violations in the 4,000 MW to 6,000 MW USS scenarios is caused by the removal of generation. The capability to adjust power factor to mitigate high voltage is not an option for DG; hence, controllable reactive devices must be installed or other measures undertaken when high voltages occur for the DG cases.

Table 3-6 presents maximum overvoltages for each zone displayed in Figure 2-1.

Table 3-6. Maximum Voltage Violations by Zone (Summer Peak, 2020)

Solar Scenario	Case (MW)	351	355	356	358	360	362	365
DG	500	No Violations at this Level						
DG	2,000	-	1.0598	-	-	1.0637	-	-
DG	4,000	-	1.0645	-	-	1.0741	-	-
DG	6,000	1.0502	1.0606	1.0517	1.0857	1.0792	1.0506	-
Hybrid	500	No Violations at this Level						
Hybrid	2,000	-	1.0609	-	-	1.066	-	1.0548
Hybrid	4,000	-	1.0575	-	-	1.0703	-	1.0581
Hybrid	6,000	-	1.0594	-	-	1.0757	-	1.0563
USS	500	No Violations at this Level						
USS	2,000	-	1.0596	-	-	-	-	1.0572
USS	4,000	-	1.0519	-	-	1.0702	-	1.0559
USS	6,000	-	-	-	-	1.0669	-	1.0545

Source: Navigant

3.2.3 Light Load Analysis

The following two sections present thermal and voltage violations for the light load cases. Similar to the summer peak analysis, the number of contingencies causing violations and the number of violations are presented by voltage, and for each DVP transmission zone and tie lines to adjacent systems. The real and reactive reserves for each case are included in Appendix B.

3.2.3.1 Thermal Violations

Table 3-7 presents thermal violation results for each of the three solar capacity scenarios for the light load cases by voltage level. The case studies include solar capacities ranging from 500 MW to 6,000 MW. There are no thermal violations in the DG scenario and only one violation (115 kV) in the Hybrid scenario. More violations occur in the 4,000 MW and 6,000 MW USS cases. Also, most thermal violations occur for USS cases on the 115/138 kV system, as the majority of USS is interconnected at these voltages.

Table 3-7. Steady-State Thermal Violations (Light Load, 2020)

Voltage		115/138 kV		230 kV		500 kV	
Solar Scenario	Case (MW)	No. of Contingencies	No. of Violations	No. of Contingencies	No. of Violations	No. of Contingencies	No. of Violations
DG	500	No Violations at this Level					
DG	2,000	No Violations at this Level					
DG	4,000	No Violations at this Level					
DG	6,000	No Violations at this Level					
Hybrid	500	No Violations at this Level					
Hybrid	2,000	No Violations at this Level					
Hybrid	4,000	No Violations at this Level					
Hybrid	6,000	1	1	0	0	0	0
USS	500	No Violations at this Level					
USS	2,000	No Violations at this Level					
USS	4,000	27	3	0	0	0	0
USS	6,000	36	8	4	3	0	0

Source: Navigant

Table 3-8 presents thermal violations reported in Table 3-2 for each zone displayed in Figure 2-1, derived from PSS/E 2020 load flow results. (Only zones where violations are detected appear in the table.) Zones 355-357 indicate intra-zonal lines between Richmond (Zone 355) and Chesterfield (Zone 357) and 315-362 are lines between Duke Energy’s Carolina Power and Light – East (Zone 315) and DVP’s Carolina (Zone 362).

Table 3-8. Thermal Violations by Zone (Light Load, 2020)*

Solar Scenario	Case (MW)	355	357	358	362	365	355-357	315-362
DG	500	No Violations at this Level						
DG	2,000	No Violations at this Level						
DG	4,000	No Violations at this Level						
DG	6,000	No Violations at this Level						
Hybrid	500	No Violations at this Level						
Hybrid	2,000	No Violations at this Level						
Hybrid	4,000	No Violations at this Level						
Hybrid	6,000	0	0	0	1	0	0	0
USS	500	No Violations at this Level						
USS	2,000	0	0	0	1	0	0	0
USS	4,000	0	0	1	1	1	0	0
USS	6,000	1	1	3	4	0	1	1

*Zone locations appear in Figure 3-2

Source: Navigant

Table 3-9 presents maximum thermal overloads for each zone displayed in Figure 2-1 from PSS/E 2020 load flow results. All values are percent of normal line rating; dashes indicate no violation was detected.

Table 3-9. Maximum Thermal Violations by Zone (Light Load, 2020)

Solar Scenario	Case (MW)	355	357	358	362	365	355-357	362-315
DG	500	No Violations at this Level						
DG	2,000	No Violations at this Level						
DG	4,000	No Violations at this Level						
DG	6,000	No Violations at this Level						
Hybrid	500	No Violations at this Level						
Hybrid	2,000	No Violations at this Level						
Hybrid	4,000	No Violations at this Level						
Hybrid	6,000	-	-	-	98.7	-	-	-
USS	500	No Violations at this Level						
USS	2,000	No Violations at this Level						
USS	4,000	-	-	-	104.1	94.6	-	-
USS	6,000	100.8	96.8	109.2	106.2	-	101.2	109.3

Source: Navigant

3.2.3.2 Voltage Violations

Table 3-10 presents the voltage violations, by voltage level, for each of the three solar capacity scenarios for the light load cases. Similar to thermal analysis, case studies include solar capacities ranging from 500 MW to 6,000 MW. Results indicate very few violations occur at all solar capacity levels above 500 MW, each of which is an overvoltage condition—i.e., there are no low voltage violations at any solar capacity level. Most violations occur for the DG cases, as the offset of real power load from unity power DG output increases the net reactive load on the transmission system.

Table 3-10. Steady-State Voltage Violations (Light Load, 2020)

Voltage		115/138 kV		230 kV		500 kV	
Solar Scenario	Case (MW)	No. of Contingencies	No. of Violations	No. of Contingencies	No. of Violations	No. of Contingencies	No. of Violations
DG	500	No Violations at this Level					
DG	2,000	No Violations at this Level					
DG	4,000	0	0	4	4	1	1
DG	6,000	18	2	3	3	8	8
Hybrid	500	No Violations at this Level					
Hybrid	2,000	No Violations at this Level					
Hybrid	4,000	No Violations at this Level					
Hybrid	6,000	6	2	0	0	1	1
USS	500	0	0	0	0	3	3
USS	2,000	No Violations at this Level					
USS	4,000	No Violations at this Level					
USS	6,000	6	2	0	0	2	2

Source: Navigant

Notably, there are fewer voltage violations for USS than for DG cases, particularly at higher solar penetration levels, as the study assumes USS provides post-contingency reactive support.¹² The ability to adjust power factor on USS generation avoids many high-voltage violations as reactive power is either supplied or absorbed, depending on the system condition or contingency.

¹² USS is not currently required to provide reactive power, but it will become a requirement for any USS that entered the PJM queue in May 2015 or later.

Table 3-11 presents the maximum overvoltages in each zone. All values are percent of normal line rating; dashes indicate no violation was detected. The 500 kV system (Zone 366) has the only voltage violations in the Hybrid and USS scenarios.

Table 3-11. Maximum Voltage Violations by Zone (Light Load, 2020)

Solar Scenario	Case (MW)	351	366	315
DG	500	No Violations at this Level		
DG	2,000	No Violations at this Level		
DG	4,000	1.0515	1.0885	1.0513
DG	6,000	1.0515	1.0905	1.0526
Hybrid	500	No Violations at this Level		
Hybrid	2,000	No Violations at this Level		
Hybrid	4,000	-	1.0860	-
Hybrid	6,000	-	1.0859	-
USS	500	No Violations at this Level		
USS	2,000	No Violations at this Level		
USS	4,000	-	1.0767	-
USS	6,000	-	1.0837	-

Source: Navigant

3.2.4 Mitigation Options

Mitigation options can include transmission line, substation transformer, and reactive support upgrades and enhancements based on commercially viable technologies and practices currently deployed by DVP and PJM. The following sections present solutions and associated 2015 costs to mitigate thermal and voltage violations presented in prior sections under summer peak and light load conditions for the DG, Hybrid, and USS scenarios.

3.2.4.1 Thermal Violations

Table 3-12 presents proposed solutions to mitigate thermal violations for each of the 4,000 MW solar scenarios for both summer peak and light load cases (designated as SP and LL, respectively)—no thermal violations were detected for up to 2,000 MW of solar.

Table 3-12. Thermal Violations (4,000 MW scenario)

Zone	Voltage (kV)	Cases	Mitigation	DG	Hybrid	USS
353	230	SP	Increase Line Rating	X	X	X
355	230	SP	Increase Line Rating			X
355-357	230	SP	Increase Line Rating			X
366	500	SP	Increase Line Rating		X	X
362	115	LL & SP	Increase Line Rating			X

Source: Navigant

Proposed solutions to mitigate overloads of 6,000 MW solar scenarios listed in Table 3-3 and Table 3-8 are presented in Table 3-13.

Table 3-13. Thermal Violations (6,000 MW scenario)

Zone	Voltage (kV)	Cases	Mitigation	DG	Hybrid	USS
362-315	115	LL	Increase Line Rating	-	-	X
362	115-230	SP	Increase Line Rating	-	-	X
362	115	LL & SP	Increase Line Rating	-	-	X
362	115	SP	Increase Line Rating	-	-	X
362	115	SP	Increase Line Rating	-	-	X
358	115	LL	Increase Line Rating	-	-	X
358	115	LL	Increase Line Rating	-	-	X
358	115	SP	Increase Line Rating	-	-	X
362	115	LL & SP	Increase Line Rating	-	-	X
362	115	LL & SP	Increase Line Rating	-	-	X
362	115	LL & SP	Increase Line Rating	-	X	X
357	230	LL & SP	Increase Line Rating	-	-	X
355	230	SP	Increase Line Rating	-	-	X
355	230	LL & SP	Increase Line Rating	-	X	X
355-357	230	LL & SP	Increase Line Rating	-	X	X
353	230	SP	Increase Line Rating	-	X	X
366	500	SP	Increase Line Rating	-	X	X

Source: Navigant

3.2.4.2 Voltage Violations

Table 3-14 presents proposed mitigation options to address post-contingency voltage violations. Violations were identified at solar capacity levels at 2,000 MW and above, and at all transmission voltages. Most violations are modest increases in voltage caused by displacement of load by solar DG operating at unity power factor. The impact of the higher, net reactive demand (e.g., lower system power factor) causes post-contingency voltages, including those on the 500 kV system, to increase above DVP thresholds. Notably, most voltage violations marginally exceed DVP limits; only a few instances of post-contingency low voltages were identified (92 to 93% of nominal), and these did not require mitigation as voltages are above DVP lower voltage thresholds. As previously discussed, there are fewer voltage violations for USS than for DG cases, particularly at higher solar penetration levels, as the study assumes USS provides post-contingency reactive support.¹³ The ability to adjust power factor on USS generation avoids many high-voltage violations as reactive power is either supplied or absorbed, depending on the system condition or contingency.

Table 3-14. Summer Peak Mitigation—Voltage Violations

Solar Scenario (MW)	Zone with Contingency	Mitigation	DG	Hybrid	USS
2,000	362	Install Switch on Capacitor Bank	X		
2,000	362	Included Above	X		
2,000	355	Install Switch on Capacitor Bank	X		
2,000	360	Install Switch on Capacitor Bank	X		
4,000/6,000	358	Install Switch on Capacitor Bank	X	X	
4,000/6,000	358	Included Above	X	X	
4,000/6,000	360	Install Switches on Capacitor Banks	X	X	
4,000/6,000	360	Included Above	X	X	
4,000/6,000	361	Install Switches on Capacitor Banks	X	X	
4,000/6,000	362	Install Switches on Capacitor Banks	X	X	
4,000/6,000	360	Install Switch on Capacitor Bank	X	X	
4,000/6,000	360	Included Above	X	X	X
4,000/6,000	360	Included Above	X	X	X
4,000/6,000	361	Install Switch on Capacitor Bank & 100 MVAR Shunt Reactor	X	X	X
4,000/6,000	361	Included Above	X	X	X
6,000	356	Install Switch on Capacitor Bank & 100 MVAR Shunt Reactor	X	X	X
6,000	356	Included Above	X	X	X

Source: Navigant

Mitigation options that address high-voltage violations include installation of switches at existing fixed capacitor banks at lower solar penetration levels, and the installation of shunt reactors at high solar

¹³ USS is not currently required to provide reactive power, but it will become a requirement for any USS that entered the PJM queue in May 2015 or later.

penetration levels. Table 3-5 includes a large number of voltage violations for the summer peak cases. For minor violations, overvoltage conditions are addressed by adjusting settings on existing equipment, such as minor adjustments to transformer tap settings at DVP’s transmission substations. Mitigation options include installation of switches on fixed shunt capacitor banks. This measure was applied mostly to DG scenarios, as the ability to adjust reactive output from USS eliminates overvoltages for the USS and Hybrid cases. Further, the addition of switches on existing capacitor banks and shunt reactors to manage bus voltages at substations is a lower cost solution compared to higher cost mitigation steps such as building new lines or pursuing significant system upgrades.

Table 3-15 presents proposed mitigation options to address post-contingency, high bus voltages outlined in prior sections. Most violations are for modest increases in voltage caused by displacement of load by solar DG operating at unity power factor. The impact of the higher net reactive demand (e.g., lower system power factor) causes post-contingency voltages, mostly on the 500 kV system, to increase above DVP thresholds.

Table 3-15. Light Load Mitigation—Voltage Violations

Solar (MW)	Zone with Contingency	Mitigation Strategy	DG	Hybrid	USS
4,000/6,000	366	150 MVAR Shunt Reactor	X		
4,000/6,000	366	150 MVAR Shunt Reactor	X		
6,000	366	150 MVAR Shunt Reactor	X	X	
6,000	351	100 MVAR Shunt Reactor	X	X	X

Source: Navigant

3.3 Transient Analysis

This section presents the results of transient studies for high capacity solar cases using the dynamic module of PSS/E. The power flow base cases from the steady-state analysis informed the dynamic analysis, as it highlights areas most susceptible to instability. Existing dynamic models and associated files needed for dynamic stability simulations were obtained from PJM. A list of dynamic simulation contingencies were provided by DVP. The analysis excludes potential ferroresonance conditions, harmonics and flicker, including those that may be caused by USS larger than the 25 MW at any single bus.

Navigant also developed dynamic models for new generation added to the initial power flow base cases beyond those in the PJM model, based on available data from solar manufacturers and other sources. The objective was to determine potential voltage and generation instability, and other transient conditions, that can harm equipment, degrade reliability (via spurious tripping of protection devices) or create certain, undesirable power quality impacts. Eight contingencies were evaluated for 6,000 MW of USS under light load because these were deemed to be the most significant events.

Preliminary results indicate the amount of solar capacity DVP’s transmission system can integrate before upgrades are needed is not limited by instability; however, sufficient generation needs to be on line under light load conditions, to ensure stability is not compromised (i.e., at or above 6,000 MW).¹⁴ Navigant expects additional stability impacts associated with other solar scenarios, including increased clustering of solar, new solar generators on other non-DVP systems, and as generator status changes over time

¹⁴ The list of generators that must be on line is omitted due to security and confidentiality considerations.

within DVP, PJM and other operating regions. Additional study is recommended to address the above, which could include detailed fault studies, frequency response and additional analysis of generator performance under transient conditions

3.4 Optimal Solar Locations

The steady-state and dynamic studies described in Sections 3.2 and 3.3 evaluate the capability of the transmission system to accommodate solar capacity. The number of violations can be reduced by siting USS to minimize its impact to the transmission system. The analysis is limited to USS, as net metering rules and customer preferences reduce the likelihood that DVP will be able to limit DG capacity in zones where impacts are highest.

Navigant analyzed the 6,000 MW USS case to determine a potential optimal siting by shifting the location of solar capacity in each zone to other substation busses within the same zone (i.e., intra-zonal transfers) to avoid violations. The re-allocation of the USS is conducted by analyzing thermal and voltage violations identified in the summer peak and light loads conditions based on the AC Contingency analysis. In addition, the area surrounding the buses with a violation was assessed to identify the direction of the flow on the lines, and to understand the contributing factors for each violation. For instance for the overload on a 115 kV circuit, we evaluated the flows upstream of the constraint. As a result of this review, we mitigated this constraint by shifting the USS to a bus that is downstream of the constraint. This was then found to alleviate the violation in both light load and summer peak cases.

By adjusting the location of 355 MW of USS by transferring the solar capacity to other busses within the same zone, 10 thermal violations which would have required system upgrades are eliminated. The remaining violations could be eliminated by transfers of USS to other zones which are able to accommodate additional solar capacity. The ability of intra-zonal solar transfers to mitigate voltage violations was less successful, as these violations tend to occur at several busses within the regional high-voltage network. For voltage violations in this case, solar transfers would need to occur on an inter-zonal basis to mitigate impacts.

There is significant complexity in determining the “optimal” locations for solar. This analysis sought to optimize solar by reducing the observed violations. However, the number and type of violations was based on a certain set of assumptions about the initial allocation of solar and other transmission system conditions. Therefore, further analysis would need to determine the optimal or preferred placement of solar facilities.

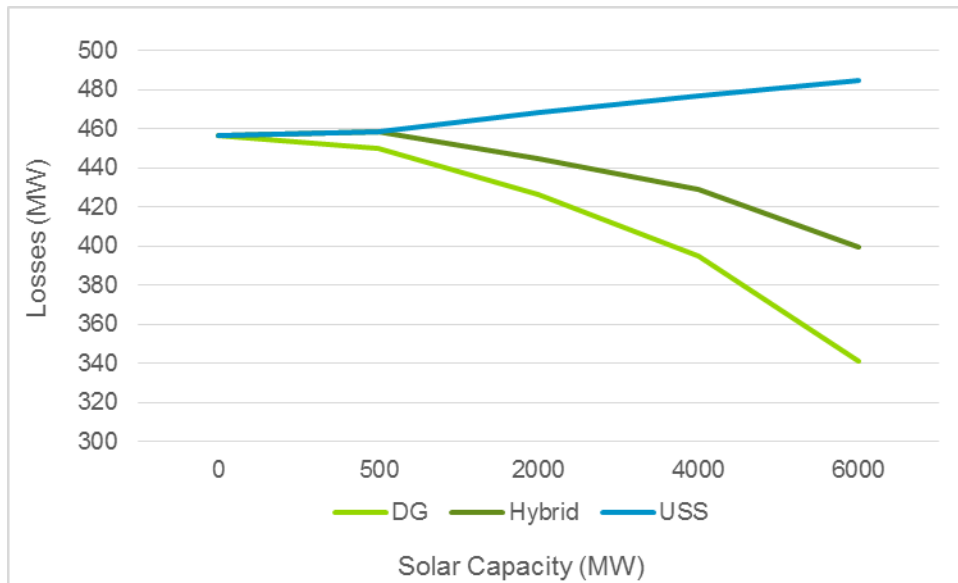
3.5 Transmission Losses

This section presents transmission loss reductions (or increases) for each of the solar scenarios. Results appear in Figure 3-3 for the summer peak case and in Figure 3-4 for the light load case. (Loss summaries appear in Appendix C.)

Results indicate a reduction in summer peak demand losses as solar capacity increases for the DG and Hybrid cases; losses increase for each of the USS cases. Loss reduction is highest for the DG cases, as DG reduces local behind-the-meter load, and highest for net loading onto the transmission network. DG is also located closer to load centers, and DG is more concentrated in areas with higher load density. Summer peak losses decrease by 30 MW (7%) for the 2,000 MW DG case and 115 MW (33%) for 6,000 MW of DG.

In contrast, losses increase for all USS summer peak cases, from 2 MW (1%) for the 2,000 MW USS case to 29 MW (6%) for 6,000 MW of USS. The USS cases produce higher losses, as USS is modeled as a generation resource, with larger amounts injected directly onto the transmission grid. This is typically in areas where loss reduction potential is lower or where incremental line loadings from injection of solar output causes losses to increase. The Hybrid cases indicate net loss reductions at all solar levels, but at lower amounts than the DG-only cases.

Figure 3-3. Transmission Losses (Summer Peak)

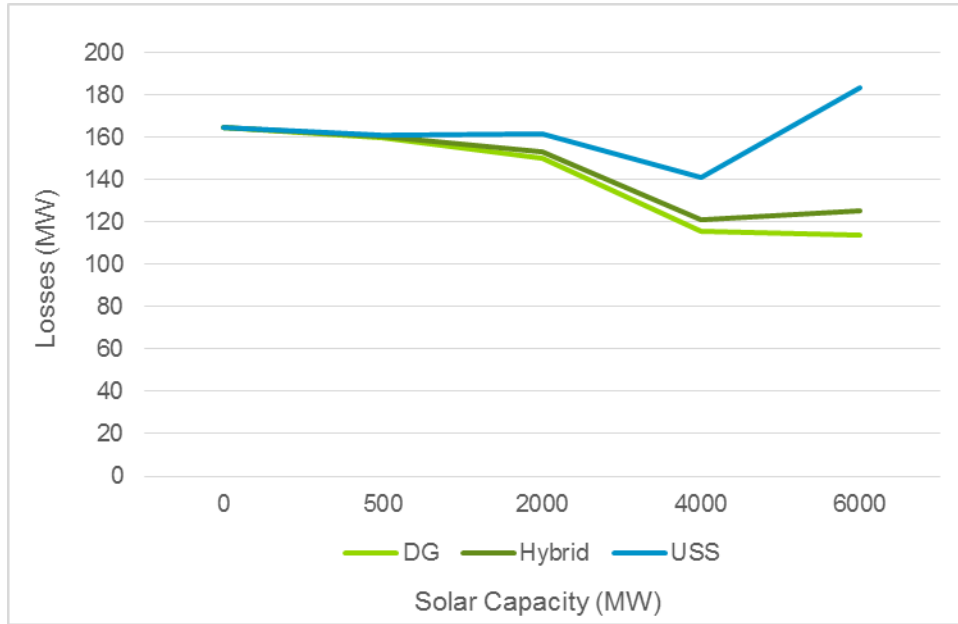


Source: Navigant

Light load losses show similar trends to the summer peak, but to a lesser degree as the net change in losses is lower. However, the percent change is sometimes greater for the light load case; for example, the maximum DG loss reduction (6,000 MW) is 52 MW, a reduction of 51%. Further, unlike the summer

where losses increase for all USS cases, losses are slightly lower for the USS scenario at capacities of 4,000 MW and lower.

Figure 3-4. Transmission Losses (Light Load)



Source: Navigant

3.6 Critical Level of Solar Capacity

The point of solar criticality depends, to a degree, on the total and relative amount of DG and USS. For the solar scenarios studied, upgrades are needed to relieve line overloads and overvoltage conditions as aggregate solar capacity reaches and exceeds 2,000 MW. The preceding analysis was based on a steady-state analysis of summer peak and light load cases. Although initial analysis is preliminary, the level of criticality may be assumed to range between 2,000 and 4,000 MW based on steady-state transmission impacts. This critical level of solar is greatly dependent on the assumptions laid out in Section 2, and further dynamic and power quality analyses will need to be completed to more precisely estimate the level of solar criticality under different solar allocation, load and conventional generation assumptions.

4. GENERATION ANALYSIS

Similar to transmission, detailed models capable of rigorously simulating generating system operations are essential to predict system impacts and energy savings. Navigant selected Promod IV (“Promod”), a power production simulation model deemed to be among the most accurate and comprehensive industry tools, to model solar on DVP’s generation system and predict energy cost savings. The applicability of Promod for solar integration evaluation has been proven in prior studies, and is the same model DVP uses for internal generation studies for a wide range of applications. More than anything, this analysis creates a process for modeling the impacts of solar on DVP’s generation system, that can be updated annually as assumptions and projections change. It is important to note that the results of this analysis provide theoretical production costs and production cost values for the year 2025. Actual future production costs and production cost savings are unknown and unknowable at this time and could vary greatly depending on actual impact of the cost category inputs (fuel, emissions, startup, variable operations and maintenance, emissions, and net imports) at that time.

4.1 Generation Model

Navigant updated the most recent version of its regional Promod model database for DVP’s generating units, and non-DVP units within its service territory, using data obtained from DVP’s internal data and Ventyx’s¹⁵ NERC 9.9 database. It includes adjustments to DVP unit parameters such as capacity ratings, minimum run, minimum load, ramp rates, unit availability, maintenance schedules, generator status, and other Promod data required to conduct the analysis. Navigant also revised generating unit ratings, variable operations and maintenance cost, and heat rate data for all major units outside DVP’s territory in PJM and in North Carolina. Other model updates included fuel and emission price forecasts, and peak demand and energy projections based on DVP estimates. Navigant then modified model databases to reflect generation additions and retirements from Plans A and B of DVP’s July 2015 IRP. Generation additions and retirements for IRP Plans A and B appear in Appendix D.¹⁶ Annual growth for peak demand and energy is 1.5% and 1.3%, respectively, over the 10-year planning horizon. This section of the analysis does not include solar development costs or impacts of upgrading the Transmission and Distribution systems.

4.1.1 Modeling Approach

Navigant evaluated solar impacts via Promod simulation studies, first by creating baseline results with no incremental DG or USS¹⁷, and then comparing the difference in cost between the no solar case versus each solar scenario. The results presented in Section 4 are snapshots for 2020 and 2025. The specific generation output and costs that Navigant compared to predict solar impacts and energy savings include assessing the impact of solar generation on the following:

- Generation unit efficiency (i.e., heat rate), emissions, operations and maintenance, and number of unit starts resulting from the displacement of conventional generation with solar;
- Generator ramping requirements associated with variable solar output;

¹⁵ Ventyx is the developer of the Promod model and various databases described herein.

¹⁶ Navigant’s analysis excludes the July 2015 DVP IRP assumption that a solar-paired CT is added for each 1,000 MW of solar.

¹⁷ The baseline, or reference case, includes 1,398 GWh of solar generation by 2025 in the DVP zone.

- Generation unit commitment schedules, economic dispatch, and online reserve requirements;
- Must-run generation resulting from solar displacement of load and variable solar output;
- Minimum loading violations that could result in “curtailed power” scenarios during hours with high solar output and low load; and
- Additional capacity needed to meet increased operating reserve requirements and to mitigate potential violation of operating limits.

The production simulation studies include upward adjustments to operating reserves and generation schedules associated with the displacement of load and conventional generating sources from variable solar output.¹⁸ Navigant independently estimated the additional operating reserves and fast-response generation that may be needed for ramping and to maintain sufficient regulating reserves. Because the impact of solar generation on generation operations is highly dependent on the amount of solar generation versus total load, Navigant conducted production simulations under two conditions: the first set of simulation analyses evaluates solar impacts on a PJM-wide basis; the second is based on DVP operating as its own balancing area in a standalone mode.¹⁹ The second set of simulations recognizes limitations of PJM model databases, which do not include solar capacity scenarios comparable to those included in this study for DVP.²⁰

4.1.2 Benefits and Costs

Similar to transmission, the simulation studies described above are used to estimate integration costs and benefits associated with integrating solar PV onto the system over the study horizon (to 2025). For generation, each scenario will include an assessment of costs and benefits presented in Table 4-1, subject to data availability and model capability:

Table 4-1. Generation Benefits and Costs

Benefits	Costs
Avoided generator fixed O&M	Higher average fuel costs (due to system upgrades)
Avoided generator capital replacement	Increased O&M (e.g., due to greater cycling)
Avoided generation variable O&M	System fuel penalty
Avoided generator fuel	Increased spinning reserves
Avoided generator emissions	Increased reliance on peaker plants in transition

Source: Navigant

¹⁸ All solar capacity, DG and USS, is modeled as a load modifier in Promod, where hourly load profiles are adjusted downward based on solar output. This approach contrasts dispatchable or must-run generating capacity, whose output can vary based on energy costs, or unit or system operational constraints.

¹⁹ The PJM-Wide analysis reflects how PJM and DVP systems operate today, where all generating sources within PJM are centrally dispatched, subject to transmission tie constraints and other factors such as must-run generation. The DVP standalone analysis assumes for purposes of this study that DVP operates as its own system (i.e. balancing area) with generators dispatched, including solar, and load served is wholly within DVP’s service territory. The latter includes non-DVP load and generation that are served by DVP’s transmission lines.

²⁰ The effect of excluding solar penetration scenarios for other PJM utilities is a potential bias in assessing costs and benefits of solar, particularly for increases in solar capacity within DVP’s service territory. Solar output displaces higher cost generating sources. If adjacent systems exclude solar, the marginal cost between respective systems increase, resulting in large tie transfers that otherwise would not occur if solar capacity were to increase at comparable rates among other PJM utilities.

The above list includes increases in average fuel costs due to units operating less efficiently. In addition, the installed solar may also replace less efficient power generation peaking units during daytime peak periods (versus early evening) by shifting the dispatch to lower cost generation. These are significant factors, sometimes overlooked, that are important to recognize in cost-benefits studies.

In addition to assessing the costs associated with solar PV penetration on DVP's current system (given the most 2015 IRP plan for integration), additional levels of penetration are analyzed to determine what levels of penetration the system can absorb.

4.2 Solar Impact Analysis

Production simulation analyses were conducted for three solar scenarios: (1) DG-only; (2) USS; and (3) a 50/50% DG/USS Hybrid scenario for increasing amounts of solar capacity. The results shown in this report are for the Hybrid scenario. Production simulation studies were completed for years 2020 and 2025 to determine how impacts and savings change over time. The scenarios are based on DVP solar forecasts from Plans A and B from its July 2015 IRP: 1,600 MW and 1,200 MW, respectively in 2025. In addition to solar capacities outlined in the IRP, Navigant evaluated larger amounts of solar, up to 12,000 MW in 2025.

The selection of a wide range of solar capacities is designed to assess production cost savings as a function of solar capacity, and to identify the level at which solar capacity reaches a level at which DVP's generation mix is incapable of meeting reserve, ramping, and/or unit operating limits.

The production simulation studies include two set of analyses to assess solar impacts, described below:

1. **PJM System Analysis:** The PJM studies are based on a centralized, system-wide generation commitment and economic dispatch that reflects the manner in which PJM operates today. It recognizes transmission constraints and economy transfers among utilities within PJM (see Figure 3-1) based on a centralized dispatch. Total 2015 PJM peak load is approximately 160,000 MW, of which about 20,000 MW is located within the DVP subzone.²¹ The PJM-wide approach better reflects actual generation dispatch and transmission constraints. However, it excludes solar growth for utilities other than DVP, thereby potentially overstating intertie sales from DVP to other utilities and creating congestion that otherwise would not be present if solar forecasts for other utilities were at comparable levels to the DVP forecasts applied in this study.²² It would be unlikely for DVP to increase solar penetration in isolation, so a DVP System Zonal Analysis was also conducted.
2. **DVP System Zonal Analysis:** The Zonal studies assume DVP operates as its own balancing area with no transmission intertie flows to adjacent utility systems. The benefit of the DVP only analysis, while theoretical, is that it more accurately reflects DVP generation impacts from solar if other PJM utilities were to install solar in amounts somewhat comparable to the solar scenarios evaluated in this study. Under the PJM approach, both DVP and other PJM generation can easily absorb IRP Plan A and B solar output (1,600 MW and 1,200 MW in 2025, respectively), as each represents less than 2% of total PJM load. In contrast, the impact of variable solar output on DVP's generation mix is far more significant, as it represents up to 10% or more of load under light load conditions, and even greater for the high penetration cases. Thus, the DVP Zonal

²¹ Approximately 2,000 MW of load within the DVP zone is municipal and cooperative load interconnected to DVP's transmission system.

²² Long-term solar forecasts for other PJM utilities similar to those used in this study for DVP do not appear in PJM Regional Transmission Expansion Plans or databases.

analysis may be deemed a better proxy of how the DVP and PJM systems would be impacted by solar displacement of conventional generation.

The results of each set of studies appears in Sections 4.2.3 and 4.2.4.

4.2.1 Solar Model

In Promod, solar capacity is modeled as an hourly load modifier for both DG and USS, with monthly adjustments for changes in average hourly output. For USS, over 80 solar units were developed for Plan A and interconnected to the busses studied in the transmission analysis. For Plan B, about 70 solar units were created and connected to the appropriate transmission busses. For DG, 125 solar units were created, but were interconnected to over 350 busses as studied in the distribution analysis, corresponding to solar capacity aggregated at individual substation busses across the state. Promod is then run with increasing amounts of solar capacity for each scenario, and impacts and costs are compared to the base, non-solar case to derive impacts for the following categories:

- Fuel
- Emissions
- Startup
- Variable O&M
- Solar Curtailment

In addition, monthly online operating reserves are increased above base case levels to meet additional ramping and regulation associated with variable solar output in the DVP system zonal analysis.²³ Navigant's approach and generation reserve adjustments are described below.

4.2.2 Modeling of Variable Solar Output

To account for variable solar output, Navigant estimated the maximum reduction or increase in solar output that would likely occur due to cloud cover, inadvertent tripping of lines connecting solar, or a solar eclipse (worst-case condition) to estimate the amount of additional online reserves needed to meet BES reliability requirements.²⁴ Navigant also relied on prior studies it performed and other industry studies, to inform its selection of incremental operating reserves.²⁵

The solar allocations presented in Section 2 indicate the maximum amount of solar or DG in each of DVP's transmission zones for Plan A (1,600 MW in 2025) is about 300 MW. The physical size of each zone varies significantly; however, the maximum amount of solar assigned to any individual transmission substation is about 100 MW, which is consistent with large solar additions outlined in DVP's July 2015

²³ In the DVP zonal analysis, operating reserve was assumed to be the largest contingency in DVP (1,710 MW in plan A and B) per the utility industry's normal practice.

²⁴ BES reserve requirements are based on North American Electric Reliability Corporation (NERC) Control Area Performance Standards (CPS), which set forth minimum requirements to ensure sufficient generation is available within a balancing area (BA) to comply with frequency and area reliability standards.

²⁵ For example, (1) *Large PV Integration Study* for NV Energy, July 2011, Navigant Consulting, Sandia Laboratories and Pacific Northwest National Laboratory; and (2) U.S. Department of Energy, Pacific Northwest National Laboratory, *Duke Energy Photovoltaic Integration Study, Carolina Service Territory*, DOE/PNNL-23226, March 2014. In the latter study, DOE/PNNL confirmed the applicability of Navigant's approach used for NV Energy and applied herein.

IRP for year 2020. Assuming total solar capacity at any individual substation was interrupted (e.g., less than one minute), the percent shift in total solar output over the entire DVP grid would be approximately 5% of total installed capacity (100 MW of 1,600 MW total). Results indicate the average maximum shift in solar output is no greater than 5%. This finding is consistent with results from prior industry studies cited above.

Accordingly, for production simulation studies, additional online reserves in the amount of 5% of installed solar capacity for each scenario are added to the 1,710 MW reserve requirement in the DVP zonal analysis. These additional reserves are assigned to meet regulation (frequency) requirements to account for fast-response ramping that cannot be met by day-ahead or intraday committed generation. This results from variable solar output due to rapid cloud cover movement and line contingencies and to account for day-ahead forecast error. The additional, online reserves for regulation are in addition to incremental generation committed to respond to increases (or decreases) in hourly ramping. The incremental committed generation is not a defined input, but is accounted for in the production simulation model logic, which commits units based on the net load (native load minus solar output). Figure 4-1 and Figure 4-2 illustrate the intraday hourly loads shifts associated with solar output.

4.2.3 PJM System Analysis

To determine the change in energy cost savings as a function of solar capacity, production simulation analyses were completed for a reference case comprised of existing solar capacity and non-solar expansion from DVP’s July 2015 IRP, and solar capacity up to 12,000 MW. Table 4-2 presents total DVP production costs based on the centralized PJM dispatch of regional generation resources, including DVP. All cost categories decline as solar capacity increases, with net imports dropping significantly in proportion to other categories. The significant decline in net imports for the 12 GW scenario reflects DVP’s decreased reliance on PJM capacity due to displacement of load by mid-day solar output; load that otherwise would be supplied by lower cost generation (relative to DVP capacity) from PJM.

Table 4-2. 2025 Projected Production Costs—PJM Dispatch (Hybrid)

Cost Category	Reference (\$ Millions)	Plan A (\$ Millions)	4 GW (\$ Millions)	8 GW (\$ Millions)	12 GW (\$ Millions)
Fuel	\$3,374	\$3,338	\$3,268	\$3,142	\$2,981
Startup	\$30	\$31	\$30	\$29	\$29
Variable O&M	\$209	\$208	\$204	\$197	\$187
Emissions	\$728	\$717	\$698	\$666	\$626
Net Imports	\$1,017	\$852	\$583	\$237	\$43
Total	\$5,357	\$5,145	\$4,784	\$4,271	\$3,864

Note: These costs do not include solar capital, development, or interconnection costs, do not reflect associated distribution and transmission costs, and the costs associated with the variability of solar.

Source: Navigant

The incremental savings associated with increasing amounts of solar is derived by comparing the total reduction in production cost by the total amount of solar energy output. Table 4-3 presents 2025 energy cost savings for each solar capacity state. Savings for Plan A (1,600 MW) is \$212 million, with

incremental energy savings of \$75 per MWh of solar output.²⁶ Incremental savings decline with increasing levels of solar, with savings dropping to \$63 per MWh of solar output for the 12,000 MW case. The cost of DVP thermal generation also declines as solar output increases, from \$53.2 per MWh for the reference case to \$42.0 per MWh for 12,000 MW of solar.

Table 4-3 also presents net changes in production cost from each successive capacity state, as a function of solar energy output (second column from right). The incremental production cost savings decline at a greater rate when measured as a function of the change in cost versus incremental solar output, from one capacity state to the next.

Table 4-3. 2025 Projected Production Cost Savings—PJM Dispatch (Hybrid)

Scenario	Production Cost (\$ Millions)	Cost Savings (\$ Millions)	Percent Savings	Solar Generation (GWh)	Savings (\$/MWh of Solar)
Reference	\$5,357	-	-	1,398	-
Plan A	\$5,145	\$212	4%	4,243	\$74.6
4 GW	\$4,784	\$574	11%	9,292	\$72.7
8 GW	\$4,271	\$1,086	20%	17,186	\$68.8
12 GW	\$3,864	\$1,493	28%	25,080	\$63.0

Note: These costs do not include solar capital, development, or interconnection costs, do not reflect associated distribution and transmission costs, and the costs associated with the variability of solar. Also, solar capacity cases, particularly those above 6 GW, assume appropriate mitigation, actions or system upgrades are undertaken to address potential instability, harmonics, ferroresonance conditions that could arise for high penetration solar, which would result in additional costs not indicated in the table. Source: Navigant

4.2.4 DVP Zonal Analysis

To determine the change in energy cost savings as a function of solar capacity under the assumption that DVP would operate on a standalone basis (i.e., as its own balancing area), production simulation analyses were completed by assuming no intertie transfers between DVP and other PJM utilities. Similar to the PJM area analysis, production simulation analyses were completed for a reference case, and solar capacity up to 12,000 MW. Table 4-4 presents total DVP production costs based on a zonal dispatch of generation resources within the DVP zone. All cost categories decline as solar capacity increases, but not at the same rate as the central PJM dispatch case results. The zero value for net imports reflects the DVP zonal assumption of standalone operation and no intertie exchanges with adjacent systems.

²⁶ All energy cost savings are for year 2025, which is based on escalated fuel and other energy cost components. Current avoided costs are much lower than values presented in this report.

Table 4-4. 2025 Projected Production Costs—DVP Zonal Dispatch (Hybrid)

Cost Category	Reference (\$ Millions)	Plan A (\$ Millions)	4 GW (\$ Millions)	8 GW (\$ Millions)	12 GW (\$ Millions)
Fuel	\$4,053	\$3,921	\$3,704	\$3,424	\$3,193
Startup	\$52	\$55	\$57	\$101	\$159
Variable O&M	\$235	\$229	\$215	\$201	\$186
Emissions	\$964	\$922	\$863	\$792	\$739
Net Imports	\$0	\$0	\$0	\$0	\$0
Total	\$5,305	\$5,127	\$4,838	\$4,517	\$4,278

Note: These costs do not include solar capital, development, or interconnection costs, do not reflect associated distribution and transmission costs, and the costs associated with the variability of solar.

Source: Navigant

The incremental energy cost savings for increasing amounts of solar 2025 energy cost savings is presented in Table 4-5 for each solar capacity state. Savings for Plan A (1,600 MW) is \$178 million (versus \$212 million for the PJM case), with incremental energy savings of \$63 (versus \$75 for the PJM case) per MWh of solar output.²⁷ Incremental savings decline with increasing levels of solar, with savings dropping to \$43 (versus \$63 for the PJM case) per MWh of solar output for the 12,000 MW case. The cost of DVP thermal generation also declines as solar output increases, but not to the same extent as the centralized PJM dispatch, from \$46.1 per MWh for the reference case to \$45.8 per MWh for 12,000 MW of solar. The incremental value of solar also declines at a greater rate than the PJM case, from \$62.5 for the reference case to \$30.4 per MWh of solar output for the 12,000 MW case.

Table 4-5. 2025 Projected Production Cost Savings—DVP Zonal Dispatch (Hybrid)

Scenario	Production Cost (\$ Millions)	Cost Savings (\$ Millions)	Percent Savings	Solar Generation (GWh)	Savings (\$/MWh of Solar)
Reference	\$5,305			1,398	
Plan A	\$5,127	\$178	3%	4,243	\$62.5
4 GW	\$4,838	\$466	9%	9,292	\$59.1
8 GW	\$4,517	\$788	15%	17,186	\$49.9
12 GW	\$4,278	\$1,027	19%	25,080	\$43.4

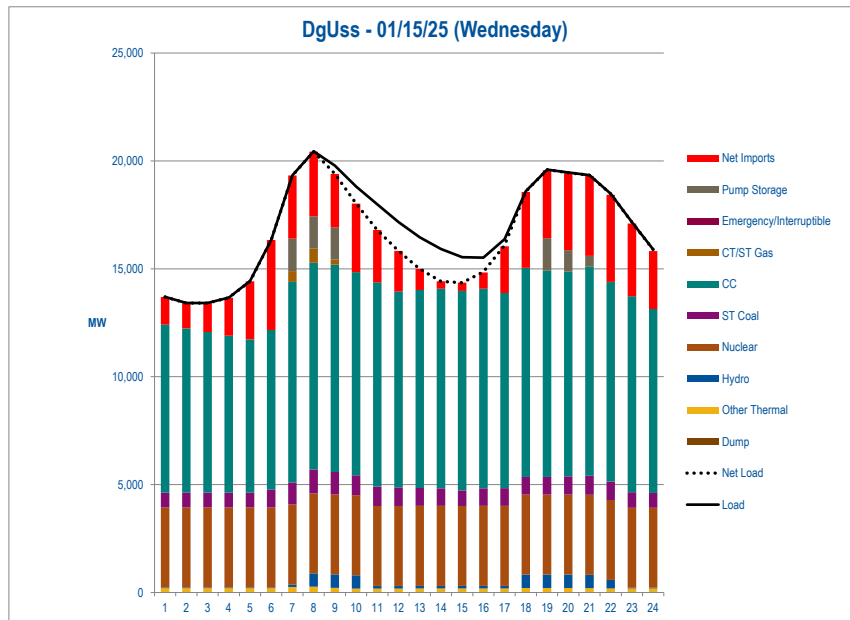
Note: These costs do not include solar capital, development, or interconnection costs, do not reflect associated distribution and transmission costs, and the costs associated with the variability of solar. Also, solar capacity cases, particularly those above 6 GW, assume appropriate mitigation, actions or system upgrades are undertaken to address potential instability, harmonics, ferroresonance conditions that could arise for high penetration solar, which would result in additional costs not indicated in the table.

Source: Navigant

At lower solar capacities, mid-day displacement of load and generation is modest, illustrated in Figure 4-1 for Plan A for a peak winter day (load net of solar is represented by the dashed line). The chart indicates mid-day loads drop slightly, with fewer imports for the PJM case.

²⁷ All energy cost savings are for year 2025, which is based on escalated fuel and other energy cost components. Current avoided costs are much lower than values presented in this report.

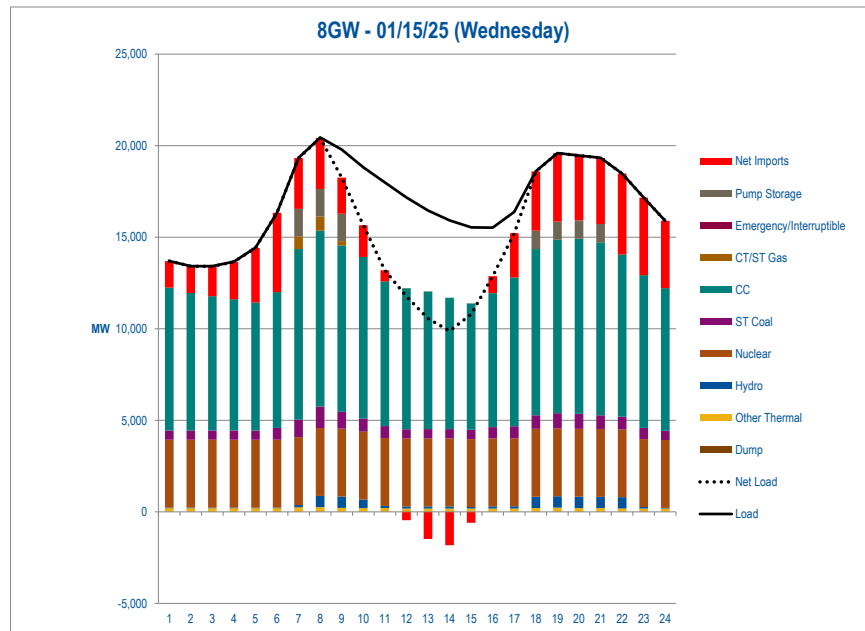
Figure 4-1. Solar Displacement: Peak Winter Day (Plan A Hybrid)



Source: Navigant

However, at higher solar penetration, there is a significant decrease in energy savings for higher solar penetrations in Table 4-5 caused by solar displacement of lower cost DVP thermal resources. Figure 4-2 illustrates a much deeper reduction in net load for the 8 GW case, confirming lower cost generation is displaced when solar displacement of load is large.

Figure 4-2. Solar Displacement: Peak Winter Day (8 GW Hybrid)



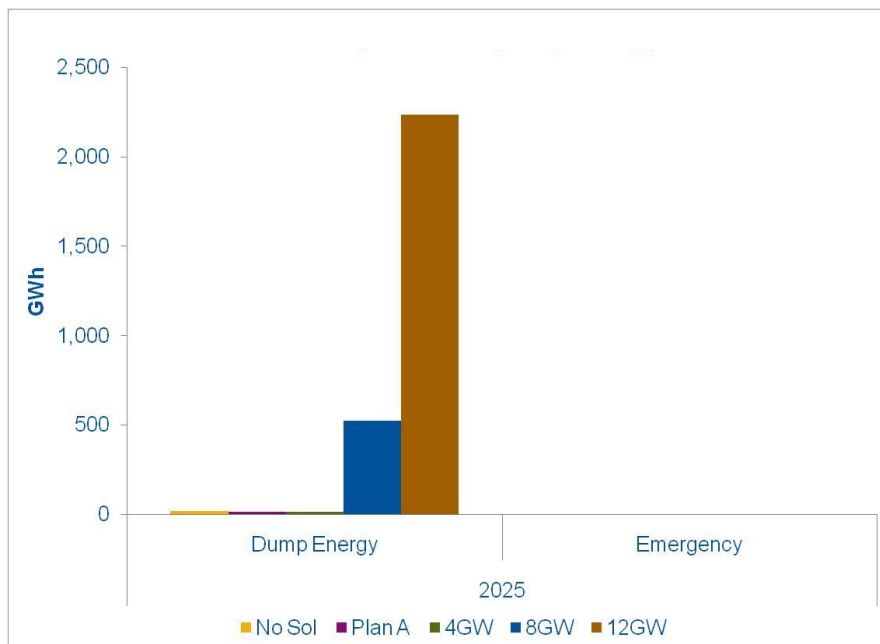
Source: Navigant

4.3 Critical Level of Solar Capacity

In addition to DVP 2015 IRP Plans A and B, which include defined levels of solar capacity additions, Navigant increased the amount of solar capacity to determine the state at which additional solar causes DVP’s system to reach criticality. For generation, criticality is defined as a condition at which fuel and operating cost savings significantly decline or when solar displacement of conventional generation causes violations of generating operating limits. The latter includes a state where NERC Control-Area Performance Standards (CPS) are not met; or when new generating capacity is needed to mitigate these impacts.

Figure 4-3 presents the amount of solar that is curtailed in the production simulation analyses for solar capacities up to 12,000 MW for the DVP zonal analysis. At lower capacities, virtually no solar is curtailed. However, at 8,000 MW and higher, curtailment increases significantly—up to 10% of total solar energy must be curtailed in the 12,000 MW case. These results suggest solar criticality, when evaluated on the basis of DVP standalone operation, is reached as solar capacity exceeds 8,000 MW or about 40 to 50% of the DVP zonal peak. This finding is supported by solar energy values in Table 4-5, where the production cost savings decline by \$10 per MWh as solar capacity increases from 8,000 MW to 12,000 MW. Based on these findings and the findings from Section 3.6, the DVP system reaches a critical level based on transmission constraints rather than generation constraints.

Figure 4-3. Solar Curtailment (DVP Zonal Analysis)



Source: Navigant

5. CONSIDERATIONS AND FUTURE ANALYSIS

As noted in Section 1.3, a number of key principles and assumptions were developed to frame this study and provide context for the findings and conclusions that were drawn and specified in prior sections. Naturally, there will be changes to these key assumptions over time, as DVP incorporates further additions of solar PV capacity within its service territory and further considers external developments in the overall solar industry, including solar additions outside DVP's serviced territory. Additional assumptions regarding the solar scenarios may also be developed and modelled, such as the inclusion of community-based solar systems, to reflect changes in future IRP assumptions.

Incremental to the defined scope of this study, additional areas for further analysis could include, but are not limited to, the following:

1. Increased clustering of DG and USS capacity within and across DVP zones, for both steady state and stability impact analyses, including further analysis of project developer/cost impacts and sensitivities;
2. Increasing the size of USS beyond 25 MW at individual busses;
3. Expanding solar scenarios to reflect current IRP expansion plans, including the addition of community-scale solar systems that are growing in others parts of the U.S.;
4. Refining the estimates of transmission interconnection and mitigation costs, including incremental costs for DVP associated with installing and operating system-wide telecommunications networks, increased distributed automation and sensors, and related software and hardware systems, training, operating and administrative costs;
5. More extensive analysis of dynamic and stability factors, including impacts associated with power system harmonics, ferroresonance, and other power quality metrics of interest to DVP; and
6. Assessment and modeling of the integration of wind, solar PV, energy storage, and other related forms of distributed and utility-scale energy resources.

6. FINDINGS AND CONCLUSIONS

This report presents Navigant's independent assessment of solar DG and USS estimated benefits and costs for DVP's Virginia service territory. This research effort is based on resource plans outlined in DVP's July 2015 IRP, focusing on Plans A and B up to year 2025. Solar capacity for Plans A and B, respectively, is 1,600 MW and 1,200 MW. The study includes evaluation of higher solar capacities to determine the level at which a state of criticality is reached, defined as a condition for which solar impacts and the estimated costs to mitigate these impacts become significant. All results were prepared using simulation tools and methods consistent with leading industry practices.

This study made several important assumption about how DG and USS could be allocated across DVP's service territory. Varying the size of individual USS projects or increased clustering of solar coupled with larger individual units could yield greater transmission system impacts, both transient and steady state. Also, the transient analysis focused on a limited set of contingencies rather than all possible contingencies. A more comprehensive transient stability analysis would further inform the true costs of solar integration. Changes to the solar allocation and assumptions for the conventional generators would result in different findings, including the system upgrades and critical level of solar for each solar scenario.

Because this study assumes that solar DG and USS were relatively uniformly distributed throughout DVP's service territory, with the largest individual unit on any substation bus set at 25 MW, the impact of variances due to cloud cover or loss of individual solar unit(s) on transmission system performance is small compared to other contingencies studied (e.g. loss of individual lines or generators). If an individual USS project is significantly larger, or more USS is clustered, the variability of solar output may have a more significant impact on DVP's transmission system when compared to findings presented herein. A study of the variability of solar output was not explicitly evaluated in the transmission analysis, but should be considered in future research efforts.

A key preliminary study finding is the determination that DVP may be able to integrate projected solar capacity (as outlined in Plan A and B up to year 2025) with few system upgrades on its transmission and generation system. However, the cost of connecting solar, including protection, communications and controls, may be substantial even where system upgrade costs are low. Distribution upgrades also may be required, depending on DG size and location, as many feeders on DVP's distribution system can accommodate modest amounts of DG capacity without system upgrades. Above 2,000 MW, solar impacts increase and net benefits decline; mitigation investment is also required to integrate increasing amounts of solar capacity.

Based on this analysis, the following findings and conclusions can be drawn:

1. The location of new solar capacity is highly dependent upon whether new solar PV is in the form of DG or USS:
 - A. USS is more likely to be installed in rural areas most suitable for large, ground-based solar, including western areas of Virginia.
 - B. DG is more likely to be installed in areas with higher incomes and housing values, such as Richmond, Norfolk, and northern Virginia.
2. Based on the study assumptions, steady-state transmission studies indicate that few, if any, thermal and voltage violations occur for Plans A and B of DVP's July 2015 IRP. Additional findings include:

- A. The amount of solar capacity, 1,600 MW and 1,200 MW for IRP Plans A and B respectively, is relatively small compared to total DVP zonal peak load (above 20,000 MW).
- B. Many violations at these levels can be addressed by adjusting equipment settings or making modest investments in voltage controls.
3. Significant, steady-state transmission violations occur once solar capacity exceeds 2,000 MW. Additional findings include:
 - A. DG impacts are mostly due to high-voltage violations, many of which can be mitigated by installation of switches on fixed capacitor banks. At higher solar levels, the addition of shunt reactors is needed to mitigate high voltages, including the 500 kV system, where violations were detected at several bus locations.
 - B. Thermal overloads occur on several lines for the 6,000 MW Hybrid case, which is mitigated by upgrading or installing new transmission lines.
 - C. The amount of solar capacity in DVP's transmission system that can be integrated, before upgrades are required, is not reduced due to potential instability; however, sufficient generation needs to be online under light load conditions when solar capacity is high, to improve stability (i.e., this condition occurs when solar capacity is at or above 6,000 MW).
 - D. Most transmission upgrades can be avoided for the USS scenario by optimally encouraging the siting of solar projects in zones and locations where impacts are low or non-existent; however, numerous factors unrelated to integration impacts also affect where solar facilities will be sited.
4. Based on Navigant's production cost modeling, average energy cost savings in 2025 achieved by solar displacement of conventional generation is \$75 per MWh, when solar capacity is 2,000 MW or lower.²⁸ Additional findings include:
 - A. Net savings in 2025 declines to about \$70 as capacity increases to 6,000 MW.
 - B. Net savings in 2025 are lower, \$63 per MWh at 2,000 MW, and the net benefit declines more sharply (\$54 at 6,000 MW), when the DVP system is evaluated on a zonal basis; that is, when DVP is dispatched on a standalone basis with no intertie transactions with adjacent systems.
 - C. The standalone DVP zonal dispatch case, although theoretical, represents a potential proxy of how the net benefits in 2025 may vary if other PJM utilities experience the same relative level of total solar capacity as evaluated in this study.
5. Navigant recommends additional research to address scenarios and issues documented in Section 5 and other areas of the report that may alter findings and results cited above.

²⁸ All energy cost savings are for year 2025, which is based on escalated fuel and other energy cost components. Current avoided costs are much lower than values presented in this report.

APPENDIX A. SOLAR ALLOCATION BY CASE AND ZONE

Table A-1. Solar Allocation by Case and Zone (MW)

Solar Scenario	Case (MW)	Solar Type	351	352	353	354	355	356	357	358	359	360	361	362	363	364	365
DG	500	DG	73	103	43	17	52	36	41	16	59	21	0	0	21	13	9
DG	2,000	DG	290	412	170	66	208	142	164	62	236	82	0	0	82	50	36
DG	4,000	DG	580	824	340	132	416	284	328	124	472	164	0	0	164	100	72
DG	6,000	DG	870	1236	510	198	624	426	492	186	708	246	0	0	246	150	108
Hybrid	500	DG	36	52	21	8	26	18	21	8	30	10	0	0	10	6	5
		USS	5	9	15	12	18	5	19	46	9	12	11	38	20	21	12
Hybrid	2,000	DG	145	206	85	33	104	71	82	31	118	41	0	0	41	25	18
		USS	19	34	60	47	70	20	77	182	35	49	45	152	80	84	46
Hybrid	4,000	DG	290	412	170	66	208	142	164	62	236	82	0	0	82	50	36
		USS	38	68	120	94	140	40	154	364	70	98	90	304	160	168	92
Hybrid	6,000	DG	435	618	255	99	312	213	246	93	354	123	0	0	123	75	54
		USS	57	102	180	141	210	60	231	546	105	147	135	456	240	252	138
USS	500	USS	10	17	30	24	35	10	39	91	18	25	23	76	40	42	23
USS	2,000	USS	38	68	120	94	140	40	154	364	70	98	90	304	160	168	92
USS	4,000	USS	76	136	240	188	280	80	308	728	140	196	180	608	320	336	184
USS	6,000	USS	114	204	360	282	420	120	462	1092	210	294	270	912	480	504	276

APPENDIX B. REAL AND REACTIVE RESERVES

Table B-2. Real and Reactive Reserves (Summer Peak and Light Load)

Model	Solar Scenario	Case (MW)	P_Reserve	Q_Reserve_MIN	Qreserve_MAX
SP	DG	500	3,528	-1,799	2,214
SP	DG	2,000	3,045	-1,471	2,026
SP	DG	4,000	2,736	-1,171	1,604
SP	DG	6,000	2,478	-903	1,351
SP	Hybrid	500	3,583	-1,860	2,132
SP	Hybrid	2,000	3,008	-1,639	2,030
SP	Hybrid	4,000	2,836	-1,292	1,794
SP	Hybrid	6,000	2,492	-1,379	1,198
SP	USS	500	3,528	-1,955	2,153
SP	USS	2,000	3,008	-1,787	2,117
SP	USS	4,000	2,771	-1,846	1,613
SP	USS	6,000	2,524	-1,703	1,502
LL	DG	500	2,000	-706	1,700
LL	DG	2,000	1,998	-633	1,587
LL	DG	4,000	2,369	-922	1,023
LL	DG	6,000	1,995	-941	1,076
LL	Hybrid	500	2,000	-710	1,718
LL	Hybrid	2,000	2,006	-657	1,601
LL	Hybrid	4,000	2,327	-570	1,575
LL	Hybrid	6,000	2,596	-595	1,726
LL	USS	500	2,000	-721	1,740
LL	USS	2,000	1,998	-762	1,525
LL	USS	4,000	2,239	-754	1,428
LL	USS	6,000	1,975	-687	1,615

Source: Navigant

APPENDIX C. TRANSMISSION LOSSES

Table C-3. Transmission Losses (Summer Peak and Light Load)

Scenario	Solar (MW)	Summer Peak			Light Load		
		Losses (MW)	Net Reduction (MW)	Percent (Reduction) / Increase	Losses (MW)	Net Reduction (MW)	Percent (Reduction) / Increase
Base	0	456.4	0.0	0.0%	164.6	0.0	0.0%
DG	500	450.0	-6.4	-1.4%	159.7	-4.9	-3.1%
DG	2,000	426.4	-30.0	-7.0%	150.3	-14.3	-9.5%
DG	4,000	394.8	-61.6	-15.6%	115.6	-49.0	-42.4%
DG	6,000	341.0	-115.4	-33.8%	113.5	-51.1	-45.0%
Hybrid	500	458.6	2.2	0.5%	160.3	-4.3	-2.7%
Hybrid	2,000	444.7	-11.7	-2.6%	153.3	-11.3	-7.4%
Hybrid	4,000	429.2	-27.2	-6.3%	121.0	-43.6	-36.0%
Hybrid	6,000	399.3	-57.1	-14.3%	125.4	-39.2	-31.3%
USS	500	458.8	2.4	0.5%	160.8	-3.8	-2.4%
USS	2,000	468.4	12.0	2.6%	161.3	-3.3	-2.0%
USS	4,000	476.7	20.3	4.3%	141.2	-23.4	-16.6%
USS	6,000	485.0	28.6	5.9%	183.1	18.5	10.1%

Source: Navigant

APPENDIX D. INTEGRATED RESOURCE PLANS A & B

The transmission and generation studies in Sections 3 and 4 include resource additions and retirement outlined in DVP's July 2015 IRP Integrated Resource Plan (IRP). Generation additions and retirements for Plans A and B are summarized in Table D-4.

Table D-4. July 2015 IRP Capacity Additions and Retirements

Resource Description	Plan A: Focus on New Solar Capacity	Plan B: Co-Fire Existing Generation with Nat Gas
Demand-Side Resources	611 MW by 2030 via current and future programs	611 MW by 2030 via current and future programs
Generation under Construction	1,368 MW in 2016 (Brunswick County CC)	1,368 MW in 2016 (Brunswick County CC)
Generation under Development	1,585 MW in 2019 (Greensville County CC)	1,585 MW in 2019 (Greensville County CC)
Solar under Construction	16 MW of distributed solar by 2016	16 MW of distributed solar by 2016
Solar in Development	400 MW by 2020, including 20 MW in 2016	400 MW by 2020, including 20 MW in 2016
Solar by Non-Utility Generators	400 MW solar (178 MW firm) by 2017	400 MW solar (178 MW firm) by 2017
Retrofit	786 MW Possum Point Unit 5 SNCR retrofit: 2018	786 MW Possum Point Unit 5 SNCR retrofit: 2018
Retirements	1) 323 MW Yorktown Units 1 and 2 by 2016 and 790 MW Unit 3 in 2020 2) 261 MW Chesterfield Units 3 and 4 and 138 MW Mecklenberg Units 1 and 2 in 2020	323 MW Yorktown Units 1 and 2 by 2016 and 790 MW Unit 3 in 2020
Repower (Coal-to Natural Gas-Fired)		1,267 MW - Chesterfield Units 3, 4, 5, and 6; 439 MW - Clover Units 1 and 2 138 MW - Mecklenberg Units 1 and 2
Offshore Wind	12 MW of offshore wind by 2019	12 MW of offshore wind by 2019
New Potential Generation	1) Two CC units, totaling 3,170 MW and one CT plant of 457 MW 2) 3,000 MW DVP-owned solar Solar-paired CT added for each GW of solar	1) Two CC units, totaling 3,170 MW and one CT plant of 457 MW 2) 1,600 MW DVP-owned solar Solar-paired CT added for each GW of solar

Source: Navigant analysis of DVP July 2015 IRP

APPENDIX E. PRODUCTION MODELING RESULTS

The charts in Figure E-1 through Figure E-5 below present production simulation results for each of the major energy cost categories for increasing amounts of solar capacity. The charts display changes in generation output, capacity factor, heat rates, NOx emissions, unit starts, and solar energy curtailment for 2025.

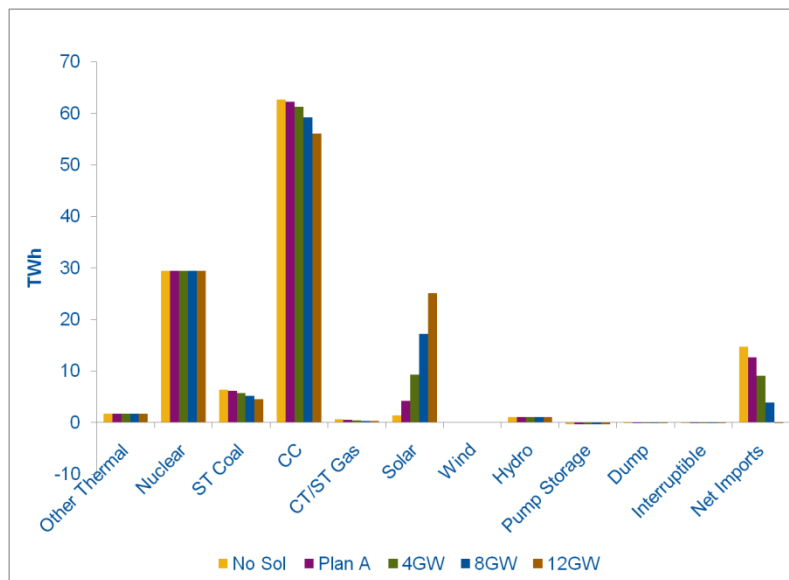
E.1 2020 Solar Scenarios Results

The trends in 2020 production cost results are very similar to those for 2025, but to a slightly lesser degree. Therefore, only charts for 2025 are presented except for energy curtailment, for which differences between 2020 and 2025 are significant.

E.2 2025 Solar Scenarios Results

The 2025 solar scenario includes capacity additions of up to 12,000 MW in 2025 for a combination of DG, USS, and a single Hybrid DG-USS scenario. Figure E-1 summarizes the amount of energy production of the DVP zone in terawatt-hours (TWh) for each generation category for increasing amounts of solar capacity for the Hybrid scenario under the centralized PJM commitment and dispatch.²⁹ Results indicate virtually all generation displaced by solar is combined cycle generation, an expected outcome as combined cycle capacity is typically the marginal unit in DVP’s dispatch schedule. Net imports vary slightly and are later adjusted to confirm that a high or low amount of intertie transaction does not bias results with regard to energy costs.

Figure E-1. Hybrid Scenario—Generation by Category in 2025

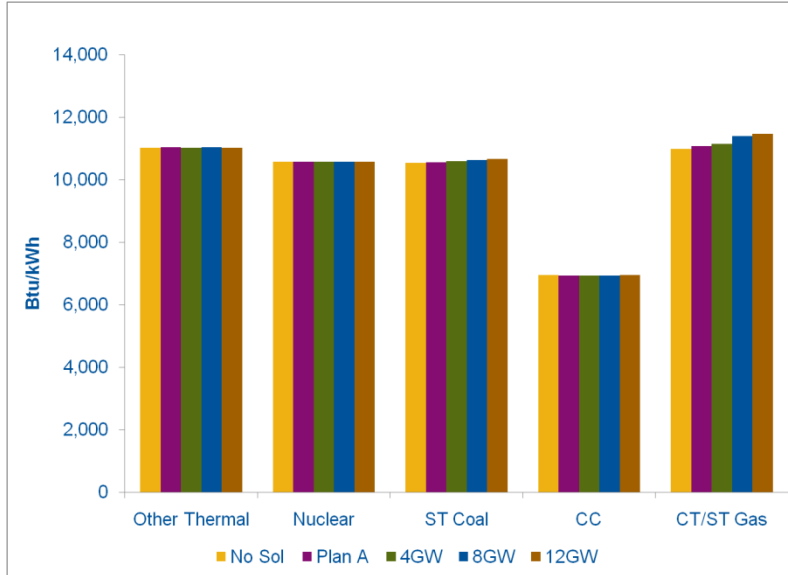


Source: Navigant

²⁹ Figure E-1 and charts that follow present results for Hybrid cases. Results for DG and USS scenarios are comparable to the Hybrid scenario results for each of the production cost categories.

Figure E-2 illustrates the change in unit heat rates for each generation category for increasing amounts of solar capacity. Heat rates for coal and other gas-fired generation show a slight increase, indicating less efficient partial loading at higher solar penetration levels.

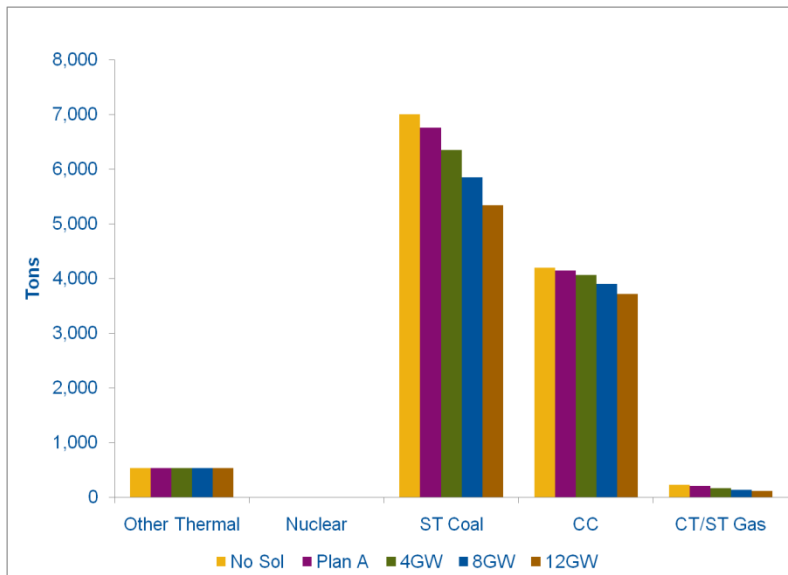
Figure E-2. Hybrid Scenario—Heat Rates in 2025



Source: Navigant

Figure E-3 confirms significant NOx emission reductions due to solar displacement, both for combined cycle and coal-fired generation. The trends show a clear correlation in NOx emissions reductions and increases in solar capacity. There are similar reductions in CO₂ and SO_x emissions as solar capacity increases. There is a small reduction in emissions reduction for other thermal generation, due to the relatively small amount of oil-fired generation on DVP’s system and low capacity factors.

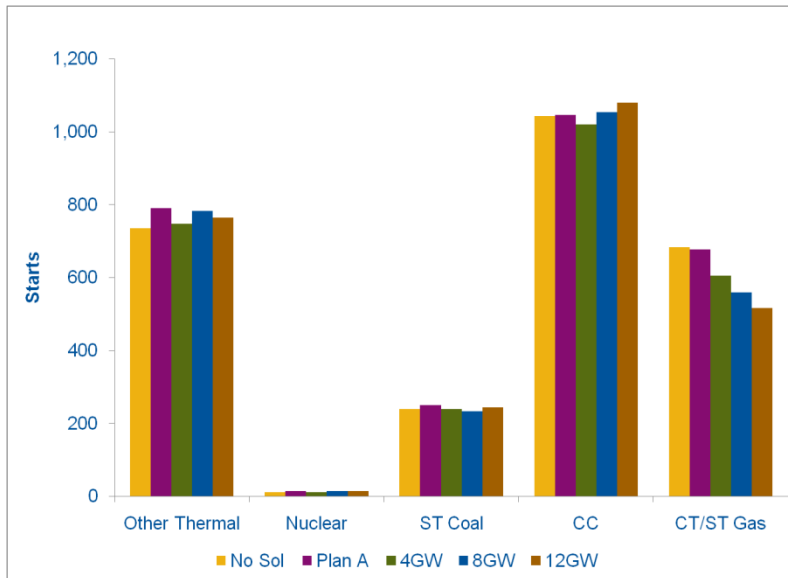
Figure E-3. Hybrid Scenario—NOx Emissions in 2025



Source: Navigant

Figure E-4 indicates the number of starts for most units decline for solar capacities up to 4,000 MW. These results suggest fewer units are committed for operation for lower capacity, an expected outcome as solar flattens mid-day loads from solar displacement. Most units with fewer starts are combined cycle units, as these units typically operate at the margin. Above 8,000 MW, the number of combined cycle starts begin to increase to meet higher ramping associated with solar displacement of load and reduced output from conventional generators.

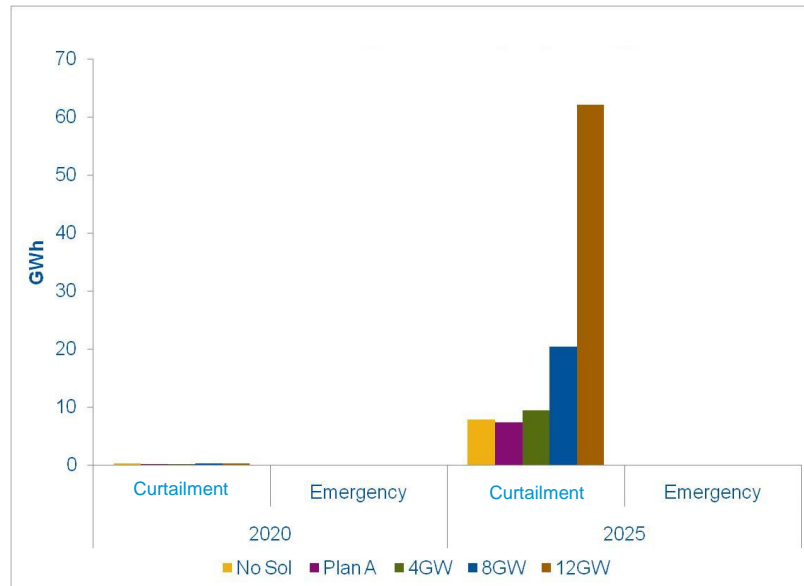
Figure E-4. Hybrid Scenario—Unit Starts in 2025



Source: Navigant

Figure E-5 presents energy curtailment for increasing amounts of solar capacity in 2020 and 2025. Curtailment in 2020 is barely visible. In 2025, curtailment is relatively low for capacities up to 4,000 MW, with a modest increase for the 8,000 MW Hybrid case; further, when compared to total energy output, all curtailments are low compared to total energy production in Figure E-1. This finding indicates that relatively few generating violations occur due to solar displacement at lower capacities, in part due to the additional reserves available from DVP’s generation mix to respond to higher ramping requirements.

Figure E-5. Hybrid Scenario—Energy Curtailment in 2020 and 2025



Source: Navigant